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Bringing energy to your door

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Sent by email to: RIIO2@ofgem.gov.uk

30 September 2020

Dear Jonathan

RIIO-ED2 Sector Methodology consultation

Electricity North West welcomes this important consultation as part of the framework development for RIIO-ED2 along with Ofgem's acknowledgement of the key role for DNOs in delivering decarbonisation, now enshrined in law and Government policy. We welcome the tone and openness of the consultation that is seeking to move the sector towards enabling the delivery of Net Zero. We support the development of a timely and appropriate framework for RIIO-ED2 that meets the challenges and changes that are occurring in our sector and that continues to deliver the essential needs of our consumers and stakeholders.

Electricity North West provide detailed responses to all aspects of the consultation in detailed appendices, but in this covering letter I want to focus on a small number of key points. I will return to the important and persistent issue of financing at the end of this letter. First of all <u>my **top five suggestions** for you to consider are:</u>

1. Innovation and incentives have been central to the successes achieved for customers in RIIO-ED1. We are pleased to see that the cornerstones of RIIO are a prominent part of the consultation. Ofgem in RIIO-1, and RIIO-ED1 specifically, set a framework that is balanced and achieved excellent outcomes for customers and stakeholders. This has been exemplified by what Electricity North West (ENWL) has achieved in many areas during RIIO-ED1 so far, such as reducing power cut occurrences by almost a quarter, shortening them when they do occur by nearly a fifth whilst making real improvements in customer service to levels on a par or better than household names like Amazon and John Lewis**. I suggest that these regulatory tools can deliver the transformational changes required in RIIO-ED2, if the incentive and innovation properties of the RIIO framework are now turned up the drive for Net Zero and the strengths of these elements are maintained.**
2. Getting to Net Zero requires an agile regulatory framework that can respond to changing priorities with pace. We support the use of reopener uncertainty mechanisms in a targeted and transparent way, but recognise they can reduce the responsiveness of the sector to changing customer and

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stakeholder needs. They work best for large, one-off projects, such as those found in Electricity Transmission but are less suited to the myriad of smaller network interventions that Electricity Distributors must continue to make across their complex networks. Here, automatic mechanisms such as volume drivers and providing sufficient upfront allowances that can be mechanistically modified will best serve customers in this rapidly changing environment. **I suggest that this approach with an enabling baseline and well-designed volume drivers will serve Ofgem well in its discussions with government to demonstrate how Ofgem is enabling Net Zero.** Providing sufficient upfront allowances, as well as automatic mechanisms such as volume drivers, will best serve customers. Predictability in the level of investment is important as it underpins the supply chain investment in its capacity to deliver. Should Ofgem become the gate keeper to regionally driven decarbonisation enablement, my team and I are ready to work with you to develop new agile decision making processes that can operate in uncertainty and take decisions based on imperfect information.

3. Return Adjustment Mechanisms (RAMs) proposed at 300 basis points (bps) on return on regulatory equity (RoRE) is too restrictive and would undermine the legitimate strength of incentives when these are considered as a collective package, potentially curbing a company's ambition to drive outcomes for consumers. However, I recognise Ofgem needs to provide extra confidence to stakeholders if companies are successful in delivering what customers value across several incentives and therefore some extra mechanism is required. **I suggest that if returns exceed the 300 basis point threshold a company report demonstrating that customers are receiving the benefits intended by the incentives is published <u>AND</u> that companies contribute 1 in every 10 bps over this threshold to a fund that will support customers in vulnerable circumstances in their region.** Something like this will enable Ofgem to increase the full RAMs trigger point to 500 basis points with confidence that legitimacy will be secured. Our stakeholders in the North West have made it very clear through our business plan engagement that additional support for those in vulnerable circumstances and those in poverty is required. Furthermore, Ofgem must include finance and tax within RAMs as this will protect customers and consumers from inappropriate returns in RIIO-2 earned by companies for example by just being lucky in the timing of their financing.

4. It is essential that Ofgem visibly demonstrates that the RIIO-ED2 regulatory framework protects customers in vulnerable circumstances and, as we recover from the economic effects of the COVID-19 lockdown, is helping those least able to pay their electricity bills. **I suggest that our innovative Smart Street technology is a key example, lowering customers energy bills by up to £70 each per annum, and that Ofgem require that a wider roll-out of the benefits of Smart Street to be included in all DNO business plan submissions targeted at areas of high fuel poverty.** Ofgem should specify this through the business plan guidance.

5. The integrity of the RIIO-ED2 framework lies in its ability to respond to legitimate regional stakeholder requirements. **I suggest that Ofgem puts regional customer and stakeholder views as a central part of the framework and assessment of DNO business plans.** We have been engaging directly with our customers and stakeholders to ensure their views are at the heart of our plan for the period of RIIO-ED2 and beyond and this is continually scrutinised by our challenging customer engagement group (CEG) of key experts. **I am also providing a copy of this letter to Andy Burnham (Greater Manchester Mayor), Angie Ridgwell and Katherine Fairclough the respective leaders of the Lancashire and Cumbria County Councils as part of our engagement with them.** Our CEG is also actively involved in assessing the RIIO-ED2 regulatory developments and we also share all our regulatory correspondence transparently with them. Local/regional bespoke service offerings and how these interact with the proposed limitations on bespoke Output Delivery Incentives (ODIs), Price Control Deliverables (PCDs) and wider interaction with the process of cost assessment must be considered carefully. Companies should not be inadvertently penalised for committing to deliverables that are valued/prioritised by customer and stakeholder engagement or have other regions deliverables imposed on their customers.

ENWL welcomes the following key initiatives proposed by Ofgem:

1. We welcome the opportunity to transition towards DSO in RIIO-ED2 and will deliver what customers need given a supportive regulatory framework. We are well on with our transformation towards DSO, including our significant and industry-leading investments in the next generation of Network Management Systems. **Ofgem should consider the impact on the outcome for customers and not just what is perceived as the leading standard. Tailoring for each DNO is the right way to ensure the optimal benefit for all consumers and stakeholders to go at the right pace for each region.** It is important that we as a DNO can continue to deliver our core services which underpin the transition to DSO in ED2 and the framework should not lose sight of this. ED2 is not time to consider separation, ED3 should review delivery, fully informed by the learning in ED2.
2. Particularly with respect to DSO, data and use of data is key and we agree this is a key enabler in a changing energy environment. **We are making substantial progress in making more of our data open and continue to support the principles and recommendations of the Energy Data Task Force (EDTF) and associated working groups, as well as actively readying ourselves as part of our preparations for RIIO-ED2.**
3. We welcome Ofgem's continued considerations of how efficiently incurred embedded debt costs should be addressed in the RIIO-ED2 framework and the potential that a special company premium may be appropriate for specific circumstances.
4. Additional clarity and guidance proposed as part of the evolution of the Business Plan Incentive (BPI) and Consumer Value Proposition (CVP) process for RIIO-ED2 is welcome. **Care should be given to not stifle DNOs ambition by being overly prescriptive in CVP guidance, areas such as Smart Street and leading decarbonisation should be included in the list of areas that can be included.** It must be clear that if a handful of strong propositions to benefit customers are put forward, Ofgem will not dismiss or penalise the company because the CVP item doesn't immediately fit the guidance area. We understand and support Ofgem's provision of further guidance, but do not want it to restrict consumer value.

ENWL seeks **further advice** from Ofgem on specific process issues:

1. Given the recognition that ED is at the forefront of Net Zero **we support Ofgem having a Net Zero Advisory Group (NZAG) and the Net Zero Innovation Board**. DNOs have a strong track record of leadership on decarbonisation and collaboration with Ofgem (recent examples include COVID-19 responses), so our trusted voices should not be ignored in the establishment of these two bodies. **There is a need for greater transparency and detail about these two bodies and the defined role they will play** and further development and publication of group scope, terms of reference (ToR) and work schedule should be a priority and cognisant of the wider RIIO-2 process. As an example, the Net Zero Innovation Board as a replacement for the existing Energy Innovation Board only has its ToR published. No minutes have been published and it is unclear what this Board has undertaken since creation in late 2016.
2. We acknowledge and welcome the engagement we have had with Ofgem to date and look forward to the continuation of this and urge that this happen at pace. **The importance of progress in working groups to meet the December decision is crucial as well as the key dependency on the Access and Charging Significant Code Review which cannot be allowed to slip.** We look forward to working with Ofgem and other stakeholders over the coming period to further develop and shape the framework for RIIO-ED2.

We note that many financing details aren't being consulted on as part of this sector specific methodology consultation, but we agree that "*underinvesting in the network now could put Net Zero targets at risk*" in turn worsening outcomes for current and future customers. **We urge that Ofgem take further stock of financial issues and adopt a more balanced approach than Ofgem appears to be taking in RIIO-2 so far.** This includes not making arbitrary adjustments through aiming down (AvE) and more balanced use of values towards the mid-points in ranges when the decisions are taken at the appropriate time. It should also consider the characteristics of RIIO-ED2 specifically and the needs to attract long term investment, with parity between both debt and equity holders.

In the low return world of RIIO-ED2 companies will not have the ability to support underfunded debt allowances with equity any longer. Therefore, our position on financeability and the inclusion of derivatives has not changed, and we will continue our dialogue on these matters with your team. If structurally companies are to receive different equity returns because of past luck in financing decisions this will have a material impact on financeability and result in a different level of Net Zero progress in unlucky regions. Financing and tax costs must be addressed by the regulatory framework in a similar manner to all other totex costs with company specific factors being included in their assessment and the implications of under or over performance included in RAMs mechanisms. We are keen to ensure that financeability is assessed on a licensee basis to ensure that whole regions are not left behind in the drive to zero carbon because investment is not available to them.

Ofgem has stated that RIIO-2 should be a lower risk, lower returns price control. However, we consider that proposals which increase the breadth of ex-post reviews, rely on a number of less clear reopener mechanisms and also reopeners that only Ofgem can trigger will **change the nature of the regulatory relationship into one of permanent and perpetual price control discussion**. This is a fundamental change to the nature of the regulatory framework, one that was recognised in your presentation of RIIO-2 to investors. **Our investors tell us that this represents a substantial increase in the risk associated with the regulatory framework.**

We are pleased to see Ofgem recognises that "*the electricity distribution networks will be at the forefront of the changes needed to support Net Zero*". It is crucial that the development of the framework for RIIO-ED2 recognise this and the unique circumstances that DNOs will be operating in in ED2 and into future price controls. **I strongly recommend Ofgem extends the timeframe for considering financing issues to the end of February 2021 and uses this extra time to commission an authoritative, academic, evidence-based report as part of the RIIO-ED2 development process.** This report should consider the effect on equity risk of the proposed RIIO-ED2 regulatory framework bearing in mind that these are complex businesses facing massive change. Additionally, I urge that Ofgem should include within this report a review of the different levels of equity risk for Electricity Distribution, comparing Electricity Distribution to Water, Transmission and Gas distribution to identify differences in risk and required investor reward.

Our detailed response to the RIIO-ED2 Sector Methodology consultation and the accompanying topic specific materials is provided in five appendices to this letter. This response should also be read in light of previous correspondence in relation to RIIO-2 and our response to the Draft Determinations submitted 4 September 2020.

If you have any questions on any elements 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

Encs:
Annex 1: Overview
Annex 2: Delivering value for money services for consumers
Annex 3: Keeping bills low for consumer
Annex 4: Finance
Annex 5: Transaction Cost Premium for Infrequent Debt Issuers

electricity north west

Bringing energy to your door

Sector Specific Methodology Consultation response

Annex 1: Overview

September 2020

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1 Stakeholder Engagement

Our RIIO-ED2 engagement has been ongoing with stakeholders and customers for a considerable time now, the output of which continues to shape our thoughts and business plan development as we gain deeper and richer insights into the role of electricity in our customers' lives and better understand our stakeholders' priorities as we continue the energy system transition.

In the past weeks we have also engaged specifically on this RIIO-ED2 methodology consultation, to directly flag the Ofgem consultation, met with our independently chaired stakeholder panels, and also held a series of regional stakeholder workshops in our three main geographical areas of Greater Manchester, Lancashire and Cumbria. The insights gained through this recent engagement have helped shape our response and have been included in our responses within this Overview document, along with the other annexes on Keeping Bills Low and Value for Money services.

We also publish our responses provided to Ofgem on our website.

2 The RIIO-ED2 process

Q1 Do you have any views on our proposal to include a statement of policy in Final Determinations that in appropriate circumstances, we will carry out a post appeals review and potentially revisit wider aspects of RIIO-2 in the event of a successful appeal to the CMA that had material knock on consequences for the price control settlement?

We have responded to this question as part of our submission to the GD/T Draft Determinations (DDs) as we consider this a principle issue that extends wider than each individual price control. Ofgem is undermining the established process of the CMA.

We understand that Ofgem's position is that "in appropriate circumstances, we will consider whether to review wider aspects of the price control settlement following the conclusion of a successful appeal to the CMA. The aim of such a review would be to ensure a coherent regulatory settlement is maintained in the event the CMA's decision has material knock on consequences for the wider price control settlement."[1]

Ofgem gives two examples of where it envisages a post appeals review may be carried out. These are:

- "The CMA quashes the decision(s) appealed and remits to Ofgem for reconsideration with a direction that Ofgem reconsider the decision and consider interlinkages; or
- The CMA quashes the decision(s) appealed, retakes the decision itself but directs Ofgem to consider interlinkages."[2]

Ofgem suggests this is not an exhaustive list, as it is difficult to set out possible future scenarios. The key issue from our perspective is whether Ofgem is intending to leave open the possibility of post appeals reviews in circumstances where it has not been specifically directed to (re)consider a matter by the CMA.

[1] Draft Determinations: Core document, table below paragraph 11.30, Ofgem
[2] Draft Determinations: Core document, paragraph 11.32, Ofgem

If Ofgem is clarifying that it will do as directed, then we do not consider that any policy statement needs to be made. A policy statement setting out that Ofgem would comply with the binding directions of the CMA is otiose.

If Ofgem is intending to leave open the possibility of further post appeals reviews, Ofgem should be explicit about its intentions, to allow parties to engage meaningfully. That said, if this is Ofgem's intention, the comments provided by ENWL in its March 2019 response to Ofgem's Cross-sector questions would continue to apply. We elaborate on those points below, similarly to our DD response for GD/T2.

- 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. The CMA is able to consider interlinkages in the appeals process. 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.
- In circumstances where, further to a decision on appeal by the CMA, Ofgem reopened and reconsidered an aspect that it was not directed to by the CMA, it is highly likely that the parties subject to any further changes would appeal this decision. It cannot be in anyone's interests – least of all consumers – for repeated adjustments to be made to price control settlements. Ofgem would also, in that scenario, need to be aware of the deleterious effect on regulatory certainty, which would increase the risk associated with investing in regulated companies (and so increase licensees' cost of equity).

In practical terms, the perceived threat (that matters will be reopened after an appeal) will mean that the consideration of interlinkages in any appeal process will be vital. Ofgem will need to set these interlinkages out at an appropriate point in the process. This process rightly begins with the regulator explaining interlinkages in its considerations and especially any decisions. Ofgem should not seek to reserve to itself the possibility of considering interlinkages other than those raised in its decision or considered in the appeals process. The threat to coherence of a regulatory settlement would only arise if Ofgem does not properly document relevant interlinkages and/or fails to raise them in an appeals processes.

Q2 Do you have any views on the proposed pre-action correspondence, including on the proposed timing for sending such to Ofgem?

We have responded to this question as part of our submission to the DDs. For ease of reference we have provided the same response in this sector methodology consultation below.

Ofgem's position is that it "expect[s] any prospective appellant to send pre-action correspondence at a sufficiently early stage after the publication of Final Determinations and ahead of the deadline for making an application for permission to appeal."[3] Ofgem makes reference to the view of the CMA, which we consider is a helpful starting point. The CMA stated:

> "We wish to encourage this pre-appeal conduct [of early, active engagement] as good practice. Where it appears that appellants have acted in a way which, without good reason, makes case management more difficult, for example appellants who fail to engage with the appropriate regulators and notify us and update us about their potential intentions to appeal, this could be reflected in our assessment of their conduct when allocating costs at the end of the appeal, even when such appeals are successful. Ideally, we would prefer such pre-notification to include the potential scope of any appeal, rather than be limited to notification of the potential existence of an appeal."[4]

While we appreciate that early and positive engagement with the regulator about appeals is a practice to be encouraged, we would be surprised if Ofgem was unaware of the likely grounds of dispute given the degree of engagement during the price control process. Moreover, there are practical reasons why it may be difficult or inappropriate to engage early. In particular, Ofgem will appreciate that deciding to bring an appeal to the CMA is often a finely-balanced decision and companies will want to see the final outcome of the price control process before deciding whether to appeal or not. Ofgem's position, that such pre-action correspondence is "expected" is not clear as to the legal effect envisaged, and it would be helpful if Ofgem clarified its position.

To the extent Ofgem is seeking to make pre-action correspondence compulsory, we would note that the process for appeals to the CMA is well-established, and laid down in legislation, supplemented by the CMA's rules on energy licence modification appeals (CMA70). Companies should adhere to the requirements of the appeal process. This process has been designed to be fair and workable to both appellants and the regulator. Prospective appellants can decide what, if any, further information they share with Ofgem beyond that which is legally required. It is not for Ofgem to add to or amend the CMA's rules or the statutory process.

To the extent Ofgem is seeking to position the lack of pre-action correspondence as a matter that the CMA should take account of in allocating costs at the end of an appeal, we would note that this too is a matter for the CMA. It cannot be for one party to an appeal to determine the terms on which costs are allocated between parties. In contrast, the CMA's view appears not to place an "expectation" of pre-action correspondence on appellants.

It follows from the above that we have nothing to add on the proposed timing for "encouraged", voluntary pre-action correspondence.

3 Net Zero and Innovation

Q3 Do you agree with our proposed approach to a Net Zero re-opener?

Our view is consistent with our response to the Net Zero Open Letter in May 2020, extracts of which are shared below. We would add that, in the interest of transparency, it would be helpful if Ofgem published the Open Letter and the responses received (subject to respondent agreement) so that

[3] Draft Determinations: Core document, table below paragraph 11.30, Ofgem

[4] CMA Response: Clarification of our position on potential Energy Licence Modification Appeals, paragraph 12, CMA

stakeholders can see respondent views and how this input has shaped Ofgem's thinking. We support transparency ourselves and have published our response on our website[5].

We note the many references to the Net Zero Advisory Board both with reference to the Net Zero re-opener and also the Strategic Innovation Fund (SIF). It would be helpful for Ofgem to provide more information on the composition and work schedule for this group as there is limited information available at present and therefore it is unclear how this will be used to inform any decision by Ofgem to trigger the Net Zero re-opener.

We also recognise that Electricity Distribution (ED) has the benefit of time (i.e. Final Determinations in 2022) where policy and pathways may be clearer compared to Gas Distribution or Transmission which are to be settled much earlier. We therefore consider that this re-opener proposal is possibly more needed and has greater likelihood of being triggered for the earlier RIIO-2 price controls than for RIIO-ED2.

Scope
We support the use of a limited number of targeted re-opener/uncertainty mechanisms that are well defined and are clear as to what risk or uncertainty they are to address in the period. We do however recognise that they can also reduce the responsiveness of the sector to changing customer and stakeholder needs. The use of automatic mechanisms such as volume drivers and provision of sufficient upfront allowances that can be mechanically modified will best serve customers in this rapidly changing environment. This approach, with an enabling baseline and well-designed volume drivers, will serve Ofgem well in its discussions with government to demonstrate how Ofgem is enabling Net Zero.

We therefore do not believe the proposed broad scope of the Net Zero re-opener meets our criteria and therefore our position is that it should be reconsidered.

The proposed broadness of the mechanism may lead to a lack of clarity for all stakeholders including companies and Ofgem about how and why it should be applied and assessed. In our response in May 2020 we cautioned against setting any Net Zero mechanism with insufficiently defined parameters; these should be tightly set, targeted and linked only to those driven by change in government policy (either central or devolved), unforeseen breakthroughs in technology driving changes in consumer requirements or significant market driven changes leading to unforeseen lower low carbon technology costs.

The wording in the consultation position of "changes connected to the achievement of the Net Zero carbon targets not otherwise captured by any other RIIO-ED2 mechanism"[6], combined with the proposal that the re-opener can be used by Ofgem at any time in the price control brings a significant degree of uncertainty and risk to companies that changes to outputs and allowances can be made at any point in time for a variety of unknown reasons.

Our recommendation is that the proposed scope be tightened in line with our suggestion above.

Process
Whilst it is pleasing to see the recognition that licensees can provide valuable input to ensure the mechanism can work effectively, it is still unclear within the consultation document what timescales are anticipated for the duration of the process described.

[5] https://www.enwl.co.uk/about-us/regulatory-information/riio2/
[6] RIIO-ED2 Methodology Consultation: Overview, table 3 below paragraph 4.13, Ofgem

As with the other re-openers or uncertainty mechanisms described within the consultation, the most critical process consideration for the Net Zero re-opener is that Ofgem will need to be able to make material decisions much more rapidly than today's processes and based, relatively speaking, on incomplete information compared to Ofgem's normal requirements for a complete and high standard of evidence. This will enable companies to react quickly to an emerging Net Zero need.

Ofgem is clear that it considers a lower returns and lower risk price control to be the aim for RIIO-2, hence any Net Zero re-opener will be reserved for actions that a company will not be able to commit to absent of regulatory agreement, as to do so would be higher risk. During RIIO-2 it looks likely that companies will have less financial flexibility to respond quickly to emergent needs ahead of Ofgem providing funding, therefore cashflow considerations will be more important in RIIO-2 and could result in shovel ready projects needing to wait for revenue to start being collected. In distribution, this could mean a two year pause until revenues can be set to fund the cash costs of investments. Supply chains would then need to be activated and then commence delivery, likely taking further time. It is therefore critical that any Net Zero re-opener process can be decided quickly and that there is timely, positive impact on the cash position of the company if further expenditure is required.

The target should be for Ofgem to make any decision and enable the company to appropriately adjust its revenues to meet any new cash expenditure needs within three months of the start of the process. These kinds of timescales might be what are needed to avoid regulation becoming a blocker to meeting customer needs. Ofgem may want to also consider whether an approach where some initial funding could be rapidly released on a no-regrets/no-hindsight risk basis to allow companies to mobilise to meet urgent customer and stakeholder needs with a short lead time, if Ofgem needs more time to make any decision(s).

<u>Materiality</u>
In setting the materiality threshold and how the re-opener might work, the RIIO-2 package in the round needs to be reviewed and Ofgem's common approach to materiality should not necessarily be adopted by default. In a lower return price control with potential for more reliance on uncertainty mechanisms or specific PCDs there is naturally much less flexibility for companies to respond as they have in RIIO-1 to changing environments. Rapid decision making by Ofgem to determine allowances and direct that companies can immediately update their tariffs to fund the obligations agreed will facilitate the responsiveness required.

<u>Interlinkages</u>
How any Return Adjustment Mechanisms (RAMs) are implemented is also key. Any re-opener funding for Net Zero would need to be adjusted for in how any RAM works.

We strongly suggest that a detailed assessment of the interlinkages between different re-openers in place be carried out and shared and consulted on with companies and stakeholders.

Q4 In what circumstances, would a centralised approach to setting forecasted outputs be appropriate? What form should this take?

We firmly believe that our customers do not benefit from centralised approaches in the forecasts used for network planning. Using national policies and information in a decentralised approach is different from a centralised approach. The RIIO-ED2 submission should not be an exception to this.

Specifically in the case of network planning, innovation projects such as our ATLAS NIA project and the business-as-usual processes of all DNOs to deliver their Distribution Future Electricity Scenarios (DFES) have demonstrated the value of decentralised approaches and in particular the need to consider bottom-up and half-hourly through year (seasonal time-series) modelling in forecasts to be able to frame regional uncertainties in network planning. The bottom-up modelling approaches consider national policies and national information but, importantly, they also consider how these will act upon the regional realities that are critical to produce meaningful regional trends. Bottom-up modelling is, by definition, a decentralised approach and therefore using a centralised or top-down approach is expected to neglect regional characteristics and be less precise.

Following a centralised approach is expected to result in using non-representative forecasting trends in regional network impact analysis. Therefore, under no circumstances could a centralised approach be preferable for distribution network planning. It should be again highlighted that using national policies and national information within a decentralised approach is different from a centralised approach. Centralised forecasts could lead to network issues being identified in the wrong place, other network issues being missed, and investments being planned in inappropriate places and times.

As an industry, all DNOs, with collaboration from the ESO, have worked closely in the ENA Open Networks[7] project to standardise the way that DNOs produce their regional forecast that have a primary focus on network planning in Workstream 1B, products 2 and 5. A decentralised forecasting approach that brings further standardisation across all DNOs has been found the most appropriate approach to capture regional uncertainties in distribution network planning. We have received positive feedback from Ofgem not only on our agreed decentralised forecasting approach in Open Networks ("initial alignment & feedback model"), but also in our ATLAS decentralised forecasting approach that has been used in our two DFES publications as well as helping most DNOs and the ESO to understand the benefits of bottom-up modelling prior to the Open Networks work.

Therefore it comes as a surprise to see Ofgem, who has previously supported decentralised approaches in our DFES, our ATLAS project work, and the common Open Networks work with all DNOs, now considering a centralised forecasting approach for the RIIO-ED2 submission. We recognise Ofgem wants to secure views on a range of options as part of consulting and we look forward to seeing the published responses. Depending on Ofgem's conclusions, there could be material impacts on the Open Networks activities in which Ofgem has been participating, which may need to change strategic direction, so earliest feedback from Ofgem is highly desirable.

There are several examples that will help highlight that centralised approaches can result in regional trends that are not representative of the regional realities. Key examples showing the inadequacy of centralised approaches for network planning are:

- **For domestic demand and heat-pump uptakes:** Centralised approaches do not consider the existing building stock (e.g. under each primary substation feeding area) and the regional potential to improve heating efficiencies due to the mix of premises under each region and/or the regional likelihood due to this mix to change their heating fuel type to electricity. Importantly for heat pumps, factors such as the access of customers to the local gas networks cannot be used in consumer choice modelling to reflect the importance of this factor to forecast regional volumes of heat pumps. This could lead to over/under-estimated demand growth and thus result in a RIIO-ED2 programme that contains a mix of under-utilised assets and/or under-reinforcement in different parts of the network.

- **For flexibility modelling (i.e. DSR, smart meters, smart EV charging etc. in general all non-DNO triggered flexibility):** Only decentralised approaches can use the local half-hourly loading data (e.g. per primary substation) to show how demand could be shifted

[7] https://www.energynetworks.org/electricity/futures/open-networks-project/

at local level and then aggregate the effects at higher voltage levels via half-hourly through year modelling. Any centralised alternative to the decentralised approach could lead to over/under-estimated demand growth and thus result in a RIIO-ED2 programme that contains a mix of under-utilised assets and under-reinforcement in different parts of the network.

- **For planned developments of local stakeholders where DNOs have received quotation requests:** This is information that DNOs gather via their direct engagement with local stakeholders (i.e. customers, Local Authorities and Local Enterprise Partnerships). Only decentralised approaches can provide confidence factors for the amount of quoted and accepted demand and generation projects per region that are expected to be energised, as well as their expected performance based on both historical performance from large sampling and per project information from direct DNO engagement with local stakeholders during the connection process. Planned developments via half-hourly through year modelling that considers the local half-hourly through year network loading can show the effects across all voltage levels in a bottom-up modelling approach. Any top-down/centralised approach could over/under-estimate demand or generation growth, both due to neglecting volumes/profiles of likely developments, and thus result in a RIIO-ED2 programme that contains a mix of under-utilised assets and under-reinforcement in different parts of the network.

- **For large scale projects that are at an early stage (connection quotes not yet received by DNOs):** Such projects can be planned developments of wide areas. We would consider these projects only in cases where adequate information through studies and technical analysis can be provided. For example, for a large domestic and commercial development we would not assume that all buildings will be directly populated, and all domestic customers would adopt EVs and heat pumps. We would consider only the Local Authority /customer plans that have well justified assumptions in the year by year demand growth, including information such as:

    - The socio-economics of the area and the affordability of domestic and commercial customers to justify the LCT uptake trends;
    - The assumptions on the diversification of demand of individual customers (in line with national or international standards);
    - The types of loads for commercial/industrial customers and the consideration of the half-hourly profiles of these loads on the demand growth.

  Any centralised/top-down approach would neglect the effects of such developments on regional demand trends. All this information needs to be used in decentralised forecasting that has bottom up and half-hourly through year modelling in its core to properly understand how the demand growth from these projects interacts with the underlying loading and the other demand uptakes, for example from LCTs. Any centralised approach cannot capture this and could result in neglecting targeted interventions at minimum cost and risk to support mature local stakeholder plans taking into account the wider regional challenges to the electrification of transport and heating.

- **For EV charging:** Regional access of customers to off-street parking and the regional potential for other types of charging (i.e. rapid charging in areas with critical traffic flows and destination charging taking into account regional behaviour of work and shopping commuters) can determine the effects of EV charging per region. Additionally, a centralised allocation of EVs that neglects the regional socio-economics can result in forecasts of much higher/lower volumes of EVs in particular areas. Therefore, centralised approaches in forecasting can result in an RIIO-ED2 programme that considers overspending or cannot facilitate the EV charging by missing the intervention requirements from the LV up to the grid and primary network.

- **For distributed generation and battery storage:** Only decentralised approaches can consider critical regional factors such as the interaction of DNO planning with customer decisions (e.g. available network capacity per BSP substation), as well as the regional land and domestic/commercial roof availability for renewable generation (PV and wind generation mainly). Also, any centralised approach is going to neglect the plans of existing generation customers to use their existing connection agreements to change their business models (e.g. from CHP generation to battery storage installations at EHV or HV networks).

Q5 What would be the factors we should take into account that would give us high certainty in a centralised approach to setting outputs?

See our response to Q4 which covers a joint response to Q4, Q5, Q6 and Q7. We cannot see any circumstances where a centralised approach would bring high certainty in appropriately setting outputs and allowances to meet essentially regional needs from different regional starting points. A centralised approach also runs significantly counter to the devolved approach to government and Ofgem's enhanced engagement approach which has effectively stimulated even greater regional input and insight to Business Plans. Finally, a centralised approach risks becoming a blocker to regional needs where outputs are underset and extra cost to consumers that needn't have occurred in other regions if outputs are too advanced.

Q6 Alternatively, in what circumstances would it be more appropriate to take a decentralised approach to determining forecasts?

See our response to Q4 which covers a joint response to Q4, Q5, Q6 and Q7. A decentralised approach but using a common framework as developed through Open Networks, is our strong recommendation.

Q7 What would be the factors that we should take into account that would give us high certainty in forecasted outputs derived through a decentralised approach?

See our response to Q4 which covers a joint response to Q4, Q5, Q6 and Q7 where we set out these factors. Some are repeated here, which all combine to ensure a robust regional approach takes place, a non-exhaustive list is shared below:

- Our sources of information are regional bottom up in many cases;
- Work via Open Networks to develop common approaches;
- Stakeholder engagement and input;
- CEG engagement and challenge.

Q8 Do you consider that the LAEP Best Practice guidance produced by the Centre for Sustainable Energy and the Energy Systems Catapult provides adequate checks and balances to ensure that local or regional energy plans are robust, unbiased and have broad support?

We apply the principles of the LAEP Best Practice checklist in our wider forecasting processes, including how we treat LA/LAEP plans. More specifically, we model LA/LAEP plans via two parallel processes:

- Process A: Projects that are part of Local Authority / LAEP plans where we have received a quotation request (methodology developed under ATLAS NIA project and enhanced afterwards); and
- Process B: Large Local Authority / LAEP projects that are at an early stage (connection quotation request not yet received).

We provide additional information at the end of our response to this question to allow Ofgem to understand a) what checks/implementation processes we adopt to model the likelihood and quantification of effects of LA/LAEP plans on forecasts (DFES used in planning); and, b) how these are in line with all principles of the LAEP Best Practice checklist.

In the wider context of which checklists are applied, it should be highlighted that our main focus is to standardise our forecasting approach and LA/LAEP plans with all other DNOs when producing our DFES, following both our developed ATLAS methodology[8] that is using a transparent and consistent across the network methodology and the agreed framework of the Open Networks WS1b P2 (whole system FES) group in the scenario definition and building block assumptions.

We believe that the LAEP Best Practice guidance and checklist could work as an additional reference to support the credibility of the modelling of LA/LAEP plans in the DFES forecasts that are used in network planning. However, we believe that some elements in this checklist require modifications to make them more suitable for this use. These modifications should include:

- Making it clear that access to source code of the forecasting models can be provided for all methodologies and associated tools that have been either produced in house by DNOs or via NIA/NIC funding that allows them to share it. There are components of these models that are subject to copyright limitations from the consultant experts used to support our modelling, for example the consumer choice models maintained by Element Energy that they have developed for clients such as Department for Transport, BEIS and Energy Technologies Institute;
- Regarding the sensitivity of non-technical factors, it should be made clear that the way the common scenario framework for DFES and ESO FES works is to model uncertainties around two main axes, i.e. societal change and decarbonisation in 2020 works. Therefore, given that this framework cannot capture all associated sensitivities (it's not a full probabilistic approach followed by DNOs/ESO), the most likely / better justified / best view assumptions are made for any non-technical factors, e.g. availability of e-vehicles by car manufacturers. In reality a request for sensitivity analysis across all factors modelled in forecasts could result in hundreds if not thousands of additional outputs with minor significance given that the major uncertainties are the ones that DNOs aim to capture when defining the scenarios;
- Regarding the engaged stakeholder plans, many of the points in the LAEP Best Guidance are applicable mainly to the LA planners rather than network companies. The guidance highlights the importance of using heat maps, which are used by DNOs mainly to provide insights to

[8] https://www.enwl.co.uk/zero-carbon/innovation/smaller-projects/network-innovation-allowance/enwl008---architecture-of-tools-for-load-scenarios-atlas/

stakeholders rather than as a feedback loop to stakeholders showing which LA/LAEP plans are more mature than others. We follow a universal approach in both our engagement with LAs and how we treat their data (see processes A and B below) and our role is to be neutral and treat all LAs equally, as well as focus on our primary network planning aim that is to assess the growth in demand and generation levels from well justified regional information and concrete LA planning actions.

Additional information on processes A and B in how we model LA/LAEP plans
In both processes we follow methodologies that aim to identify the most likely prediction and assess the associated effects on regional demand and generation growth. More specifically:

- In **Process A**, these projects are mainly HV demand connections and we use confidence factors derived from regional historical analysis to model them as half-hourly through year demand increments. So if, for example, there were 10 quotes for commercial developments of 10 MW total maximum import capacity under the same primary substation in Greater Manchester, using our 2020 confidence factors (to be used in DFES 2020) for HV demand in the south of our region we would apply a 25% confidence factor (36% if it was an accepted quote) for the energisation and then a 40% confidence factor for the demand growth in first year and 41% confidence factor for the second year.

  So, out of a 10MW of capacity for these projects we would model a 25% x 40% x 10MW = 1 MW or 10%. The assigned profile would follow the same profile with the hosting substation, unless there was a specific type of demand where we would assign a case-specific profile. It should be noted that due to the half-hourly through year modelling that we follow, this 1 MW of demand growth would appear as less than 1 MW growth at higher voltages (e.g. 132/33kV BSP substations) due to the difference in the time of peak demand.

- In **Process B**, such projects can be planned developments of wide areas. We would consider these projects only in cases where adequate information through studies and technical analysis can be provided. For example, for a large domestic and commercial development we would not assume that all buildings will be directly populated, and all domestic customers would adopt EVs and heat pumps. We would consider only the LA plans that have well justified assumptions in the year by year demand growth, including information such as:

  - the socio-economics of the area and the affordability of domestic and commercial customers to justify the LCT uptake trends;
  - the assumptions on the diversification of demand of individual customers (need to be in line with national or international standards);
  - the types of loads for commercial/industrial customers and the consideration of the half-hourly profiles of these loads on the demand growth.

Q9 Which of the uncertainty mechanisms and incentives in Appendix 3 will be most effective in enabling efficient strategic investment?

Of the uncertainty mechanisms presented for strategic investment in Appendix 3 we believe the Capacity Volume Driver will be most effective in enabling efficient strategic investment for the reasons detailed below:

- Volume driver with the measurement of capacity is able to cater for all load related drivers, whether that be general load growth, consumer behaviour, LCT adoption, generation or demand connection
- Setting ex-ante allowances with a volume driver to revise allowances based on capacity created/released enables anticipatory investment
- Capacity Volume Driver is in alignment with Ofgem's design principle 24[9]
- Well-designed volume drivers are simple and effective; they can be mechanistic in the way they are able to adjust revenues via annual iteration process rather than an alternative of lengthy reopeners
- Volume drivers are able to provide funding to allow networks to ensure delivery with no blocker for investment
- Customers only pay for what is created, ensuring there are no windfall payments as funding is solidly linked to creating capacity
- Volume drivers can stimulate non-traditional solutions like flexibility and other new innovative approaches to providing capacity because the TIM ensures the most efficient solution will be selected
- Volume drivers are reactive to changing needs and levels of certainty without the need for re-openers
- Decisions will be backed by transparent and robust processes
- Volume drivers are complimentary with other regulatory mechanisms in the ED framework; TIM drives the company to the most efficient solution and there are natural checks and balances via TTQ, BMCS, and new inclusions such as fair treatment for customers and connections

Supported by the majority of other DNOs and stakeholders ENWL has developed the approach of a Capacity Volume Driver for load related expenditure (LRE) in RIIO-ED2. The driver was to develop a mechanism that was simple, easy to understand and apply and facilitates anticipatory investment, whilst ensuring the appropriate consumer protections are in place. The unit rate(s) can be set from the current information on annual RIGs submissions (from DPCR5 and RIIO-ED1) and any trials can be managed through the last two/three years of RIIO-ED1. Therefore, the recording and reporting in RIIO-ED2 of additional units of capacity added to network levels, and their cost will be relatively straightforward. More importantly, when applied in conjunction with the TIM mechanism, DNOs are incentivised to deliver each unit of capacity as efficiently as possible, putting flexibility on an equal footing with network-based solutions and creating a strong incentive to use new ways of providing capacity where cost effective for customers.

Of the other options discussed in appendix 3, our views on each are shared below:

A **Price Control Deliverable (PCD) with funding trigger** linked to regional plans will be unlikely to be able to cover all the eventualities that may occur in a particular area over a five-year period. It would need a granular level of planning for each potential outcome and, as Ofgem states, is more applicable when the solution is known but the need uncertain. This option does not provide sufficient flexibility and would risk DNOs delivering a pre-determined outcome. This may not always be in the best interest of customers and risks removing the option of a flexibility solution which may present itself in period.

[9] "*Where there is material uncertainty in the evolution of quantities (but unit rates are stable) at the start of the control period, volume drivers should be used to adjust allowances within the control period.*" - RIIO-ED2 Framework Decision, RIIO-2 design principle 24, Ofgem

A **re-opener** is akin to the mechanism used in RIIO-ED1; however, as has been discussed in the working groups, there are several reasons why there are better options for RIIO-ED2, such as:

- challenges in setting the predetermined expenditure level and appropriate % trigger;
- time taken to submit re-opener application and Ofgem decision making delaying overall decarbonisation aims and objectives; and
- the risk of disallowance of costs during ex-post assessment may result in companies being risk-averse and limiting anticipatory investment

Whilst we are supportive of the use of a volume driver for strategic expenditure for RIIO-ED2 we do not believe that the use of the **Low Carbon Technology (LCT) volume driver** as described is the most effective solution. A volume driver of capacity provided measured in MWs added is preferential for customers, regardless of the use of the extra capacity, whether for a particular LCT or something else.

Whilst LCT is an important aspect driving investment need, it is only one specific aspect of the expected demands on our network in the future and therefore investment affecting capacity for other reasons would need further separate mechanisms to manage allowances, bringing complexity to the price control. Equally importantly is the fact that LCT adoption is one step removed from DNOs' primary role of providing network capacity to our customers to use for their own needs, whether it is demand or generation/storage. There is no direct correlation between LCTs connected and the work required on the network as this depends on a range of factors such as existing network capacity, clustering, diversity and regional topography amongst other things.

We also note that in RIIO-ED2 a key change will be the increase in the volume of electric vehicles (EV). As such DNOs will need to provide network capacity in various locations to accommodate their charging; for example, at home, at work, at service stations and destination locations. There may be differences between where an EV is registered and where it charges, and this could span DNO areas. It is therefore not clear if, based on LCT, who would account for the additional capacity required in this example of non-static LCT such as EVs. Equally the recording of EVs may be problematical and is outside of the direct control of DNOs.

In the North West we are encouraging our customers and local stakeholders to become more energy conscious and asking them to be more energy efficient, including through the adoption of LCTs for heat and transport, as well as considering generating their electricity from renewable sources. But ultimately it is up to the customer, nudged along by national and local policy changes supporting delivery of the Net Zero carbon targets to lower their carbon footprints. We need to have a mechanism that is flexible and easy to understand and track, and that enables DNO to provide the network capacity required by our customers, when it is needed. This, we believe, is most effectively achieved by the Capacity Volume Driver.

We have reservations on the need for a specific incentive mechanism related to utilisation over and above TIM, but do see the need to ensure that DNOs make the right choices by the reporting and analysis of network utilisation metrics to ensure capacity is created where it is needed at the right time. As previously stated the use of a more disaggregated set of load indices (LIs) applied across all voltage and network levels is the way to achieve this, but this requires full smart meter penetration, or a mix of aggregated smart meter consumption data supplemented with local monitoring.

We would like to work with Ofgem, all other DNOs and wider stakeholders to develop the utilisation metrics and the methods and costs to provide them within the Ofgem Overarching Working Group (OAWG). Metrics might require implementation during RIIO-ED2 and where they rely upon additional monitoring that in itself might be progressively deployed over a longer period than RIIO-ED2 itself.

Q10 Do you agree with our proposals to increase levels of BaU innovation?

In principle we support the objective to increase the levels of innovation delivered through base revenue and incentives as opposed to using a ring-fenced stimulus. However, as Ofgem rightly recognises in its consultation, there are practical constraints on the types of innovation that could be pursued through the base revenue which thereby limit an operator's ability to construct the business case necessary to justify the inclusion of BAU Innovation within its Business Plan.

Naturally BAU innovation will be necessarily limited to lower risk, rapidly deployed projects that seek to rollout previously proven innovative solutions across the network and that will payback within the RIIO-ED2 price control. This will require the innovative solutions that comprise BAU Innovation to be 'shovel ready' at the time of Business Plan submission, allowing the network operator to move the solution into BAU quickly and thereby increasing the period of time any associated benefits are accrued, which will be shared with customers.

Innovative solutions which arise during RIIO-ED2 or those with benefits which accrue mainly, or entirely, to consumers rather than to networks, e.g. Smart Street, would risk not being rolled out without a mechanism such as the Innovation Rollout Mechanism (IRM) in place to support the additional expenditure required. Our stakeholder engagement as part of this response elicited that stakeholders endorse the wide scale deployment of programmes such as Smart Street which, in addition to preparing the network for the future, that will save customers money, without relying on behavioural changes or the need for households and businesses to accommodate new technologies. Therefore, Ofgem should consider a mechanism whereby innovative solutions, which are focused on consumer benefit (at additional cost to the network company when compared to BAU approaches), are able to be rolled out in RIIO-ED2 otherwise customers will see delays to potentially considerable benefits.

As a result of the IRM application within RIIO-ED1, we consider our continued rollout of Smart Street in RIIO-ED2 as being suitable for inclusion in our BAU innovation plans and should be adopted by other DNOs.

Q11 Do you agree with our proposed methodology in relation to the RIIO-2 Strategic Innovation Fund?

We broadly welcome the introduction of the Strategic Innovation Fund (SIF) as it appears to widen the innovation focus beyond the electricity networks, including other energy vectors such as heat. This would appear to have the potential to allow for the funding of projects not currently allowable under NIC, such as those beyond the electricity meter, which are of net benefit to consumers.

It is important however to obtain a suitable balance between complexity and deliverability, and to avoid the SIF becoming overly expansive and as a result increasingly hard to prepare and, ultimately, deliver projects.

We would also be particularly keen to ensure that projects such as CLASS and Smart Street, which stand out as having strong customer benefit cases, and are highly innovative in nature, remain viable for funding through SIF. Both these projects include highly technical, network centric deliverables, not necessitating or requiring the element of co-ordination and collaboration perhaps envisaged within the SIF but, owing to being beyond the scope of NIA, wouldn't have been possible to progress without NIC. In introducing the SIF as a replacement to NIC, Ofgem should seek to ensure that projects such as CLASS and Smart Street don't inadvertently fall between the gap in innovation funding (i.e. between NIA and SIF).

We look forward to learning more about SIF and having further opportunity to comment on its practical application in due course. We note the SIF is ambitious, and there will be lots of work needed to ensure the processes are well understood, practical and ultimately fit for purpose. Similarly, it is our view that ongoing support and regular review will be required to ensure SIF delivers its aims throughout the period of RIIO-2. Ofgem need to be cognisant that this might attract a considerable overhead dependant on the requirements.

We would add that there are a number of references to the Net Zero Advisory Group and the Net Zero Innovation Board, however there is currently limited visibility on these and would encourage greater transparency on these bodies, their composition and role in innovation within the energy sectors.

Q12 Do you agree we should adopt a consistent NIA framework for DNOs, and other network companies and the ESO?

We are supportive, in principle, of this approach in that the innovation framework for RIIO-ED2 should allow interaction with other sectors.

Work on developing industry innovation strategy together with the use of the single allowance for the length of the price control[10] ought to go a long way to helping collaboration and consistency where in consumers' interests.

Given the RIIO-ED2 price control will be set two years after the other sectors, it is important to ensure that the desire to set the NIA framework consistently for all sectors does not result in it being too fixed for ED. It is entirely possible that the passage of time brings a greater understanding of the necessary innovation focus for ED, and it should be possible to reflect this within the RIIO-ED2 NIA framework, even if that means it is not identical to the other sectors.

Q13 What are your thoughts on our proposals to strengthen the RIIO-ED2 NIA framework?

We believe the proposals to strengthen the RIIO-2 NIA framework are sensible and the direction of travel for NIA is consistent with the broader aims of stakeholders. To appropriately satisfy these aims, the drafting of all associated changes to the NIA governance document will be crucial, ensuring that the strengthening is effective and as intended. We believe the ENA and its member companies can add considerable value to this process, and we are pleased to note Ofgem's intention to hold workshops on drafting updates to the governance.

We are comfortable with the proposals that eligible projects should be focused on issues associated with the Energy System Transition (EST) or that they seek to address a particular consumer vulnerability. We consider this narrowing of the focus from that of RIIO-ED1 to offer potential for better alignment across networks thereby increasing the opportunity for collaboration between companies. However, as with any change to the eligibility criteria, there is a danger that a project, such as transformer oil regeneration, which sought to introduce a viable method of extending the safe operating lifespan of transformers and which is now BAU, would not meet the new proposed qualifying criteria for NIA, nor, owing to its being a high-risk, long-term project, would it meet the expected threshold for BAU Innovation.

[10] RIIO-ED2 Methodology Consultation: Overview, paragraph A4.22, Ofgem

Given this, we believe that careful consideration of the appropriate definition of EST and, for similar reasons, customer vulnerability should be given so as to avoid potential for innovations such as oil regeneration being considered ineligible for funding thus risking innovative projects like this not being done at all. Clearly, such an outcome would not be in the best interests of vulnerable customers and customers more generally who might otherwise have benefited from the increased efficiencies.

We are broadly supportive of the proposal to require all NIA projects to develop solutions that deliver net benefits to customers in the relevant sector as it is these customers that pay for the projects in the first place.

We are pleased to see inclusion for consideration of the impact of innovation upon vulnerable consumers. This is an important development and one we aim to address in part through our Smart Street project which, through its reductions in energy consumed, is expected to deliver significant savings to over 20,000 vulnerable consumers during RIIO-ED1 and continuing into RIIO-ED2. Further one of our stakeholders stated that they “support the focus on innovation stimulus funding on addressing consumer vulnerability.” Further they “agree with the Ofgem proposals to provide support for innovation that DNOs would not otherwise undertake, where this addresses the key strategic challenges that are raised by the decarbonisation agenda or provides support for vulnerable consumers.”

We fully support the aim to increase third-party involvement in NIA. It’s crucially important that all network operators continue to engage fully and effectively with third-parties as appropriate on network innovation.

On proposals for the development of a collective guidance document for third-parties covering IP, we are not convinced that this will address the issues of inconsistency between DNOs that is its stated aim. Matters of consistency in application of the governance document are perhaps best addressed through the collaborative working between organisations, most probably via the ENA, to agree, for example, a set of common legal terms covering IP, which can be understood and adopted across all parties seeking to draw upon NIA. This could form part of planned future work on re-drafting of the NIA governance document.

Q14 Do you have any additional suggestions for quality assurance measures that we could introduce to ensure the robustness of RIIO-2 NIA projects?

Whilst needing to avoid costly post-project completion reviews which would appear to offer only limited value, particularly given the high volume of NIA projects, we broadly welcome the addition of quality assurance measures in respect of the robustness of NIA projects in RIIO-ED2. To add most value this ought to happen at the start of the process during project registration and continue through its delivery.

We consider quality assurance is most effectively and efficiently achieved through self-auditing of projects, including within this all aspects of NIA project reporting (i.e. project registration and annual and final reports). Further, we believe the ENA can play a key administrative role in this, perhaps through facilitating an ‘annual audit report’ of the portfolio (or a selection based on theme) of NIA projects.

Furthermore, individual network operators ought to consider establishing ‘innovation links’ with a network of relevant stakeholders (perhaps including Local Authorities, Universities and technology providers) who could be approached to provide the necessary quality assurances being sought.

Q15 Do you agree with our proposed approach for setting individual levels of NIA funding?

We strongly agree with this approach. Throughout RIIO-ED1 ENWL has consistently found its innovation ambitions constrained by its allowances. In a nutshell, we have more ideas than we have funding to support. While we worked with other DNOs to encourage them to address many of the issues we believed were important to support the transition to low carbon, it is not always practical to directly influence the work of other network operators.

We believe that ENWL has excellent innovation credentials, delivering innovation into BAU as evidenced by our two LCNF Tier 2 projects now operating effectively in BAU: CLASS and Smart Street, the latter being rolled out currently with an expectation of being operational by 2023. We were the DNO that worked with Kelvatek on the development of its Bidoyng and Weezap devices that are now used in their thousands by all DNOs. This places us in a fantastic position to take on a greater share of the overall innovation effort. In RIIO-ED2 our Business Plan is likely to include a higher allowance for innovation than was provided in RIIO-ED1 and Ofgem's proposal to set levels individually would appear to support our innovation ambitions.

4 Modernising Energy data

Q16 Do you agree with our approach to regulating digitalisation and better use of data through the introduction of cross-sector licence obligations?

We broadly agree with the approach taken in this area and provide our further comments below on the definition and strategy set out within the SSMC. The one element we would change is the update frequency on the digital action plan progress which should be reconsidered.

<u>Definition</u>
With reference to the statement "Digitalisation, in this context, means making better use of energy system data and digital technologies to generate value for consumers and stakeholders more generally."[11], whilst we generally agree we would expand this to include the transformation of business processes and associated business change for a true digital transformation. Digitalisation should not be solely about data and technology but also about people and process.

<u>Strategy</u>
In terms of the Digitalisation Strategy in December 2019 we took the decision that, along with voluntary publication and submission to Ofgem, we would also publish a consultation document to gather feedback from stakeholders. We are in the process of refining the strategy following that feedback and extensive internal review for future publication. We are happy to follow this publication approach as defined by Ofgem within the SSMC.

<u>Licence Obligations (LO)</u>
We understand that Ofgem considers that a LO on a Digitalisation Strategy, Action Plan and adoption of best practice are expected to bring benefits in line with Energy Data Task Force findings however

[11] RIIO-ED2 Methodology Consultation: Overview, paragraph 5.1, Ofgem

more work needs to be done to understand how energy data is used by stakeholders before we can say how and to what extent benefits will flow through to consumer benefits.

Ofgem's area of focus is on data rather than business transformation through digitalisation. We have taken the route of producing an overall digitalisation strategy with a data strategy being a sub-strategy to that. With the proposal to make the publication of these strategies and action plans a licence obligation there is more work to do to clarify what the focus of the strategy should be and what standards are relevant. There are many views as to what good looks like when it comes to strategies for data and/or digitalisation and a better understanding of how companies will be measured on this is required. We welcome the opportunity for greater discussion on this and recommend this takes place via the ENA Data Working Group and that further clarity be provided within the Sector Specific Methodology Decision (SSMD) due later this year.

If the real need is for data strategies, then we would propose that a thirteenth EDTF data best principle could be "the development and maintenance of a data strategy".

With regards to the proposed frequency of publication, we agree with the two-yearly frequency for publication of the strategy document but feel the six-monthly requirement for the publication of the action plan is too frequent. Such frequency will place a significant burden on companies in terms of preparation and approval for external publication and will result in engagement fatigue quite quickly.

Opening up our data and being transparent in terms of justification for sharing, data quality and coverage, would make it significantly easier for third parties to hold us to account. We think this could be better for consumers and stakeholders, further enhancing confidence in our actions and may in turn facilitate a lighter touch in terms of regulation as capabilities mature and stakeholder and consumer groups have better visibility of what we do and how we perform.

We are aligned to the principles of best practice guidance and the principle of presumed open data, triaging such data and building this into governance structures will be the next steps we take.

We caution however that some aspects of the guidance will bring significant challenges and compliance costs and this needs to be considered when allowances are set in this area. Uncertainty over the standard approach to be taken means that companies may not be able to fully estimate the work involved in transitioning to a standard specified model.

The subject of data which networks do not routinely collect but may be requested by stakeholders also needs to be considered, with guidance and expectations to be shared so that companies and stakeholders are clear on areas of responsibility and funding.

There also needs to be consistency across companies with regards to triage and what data sets are gathered and published.

We welcome the EDTF best practice guidance and consider the concept of working from a state of "presumed open" rather than from "presumed closed" a good approach to encouraging data sharing, insight and innovation. We are a proactive contributor in the industry wide 'Data working group', recently established by the Energy Networks Association (ENA). This group focuses on the digitalisation of the networks across electricity and gas, including provision of network data in line with the recommendations of the Energy data taskforce. We are working with other members to identify new data fields, or value from existing datasets to maximise benefits for consumers.

We do recognise some of the challenges of working towards the EDTF recommendations and following some of the data best practice principles. There is a risk that meeting EDTF recommendations could drive up network company costs to serve consumers, without clear benefits that are known at this stage.

We welcome Ofgem sharing their view of the risk that is appropriate for customers in how much they fund network company activities delivering EDTF recommendations against potential benefits that may arise, often outside the sphere of the network company's own activity where cost arises or where benefits might be risky and uncertain.

5 DSO Transition

Q17 Do you agree with the proposals we have set out to support optionality for wider institutional change should we later decide to separate DSO functions from DNOs? How else could the methodology support optionality?

We support the proposed approach to develop the optionality for institutional change by placing requirements on network operators to record and report costs and outputs in those areas identified through Business Plan submissions and industry agreement.

This however, should be the only proposal taken forward in RIIO-ED2; we do not support or believe there is a need to introduce a re-opener for separation in RIIO-ED2 as it is too soon to consider fundamental restructuring of the industry. RIIO-ED1 and the RIIO-ED2 price control periods are the opportunity for the DNOs to develop and hone the tools and techniques needed to fulfil the new DSO functions and activities on the journey to Net Zero. ED3 price control discussions should be the time to consider whether it is appropriate for a revised industry structure. There are other regulatory approaches including additional licence requirements that are available to Ofgem and would be more proportionate than revised industry arrangements.

The substantial work undertaken in the ENA Open Networks project revealed that RIIO-ED1 and RIIO-ED2 are the time periods for the industry to work in collaboration, co-ordinating activities for whole system outcomes whilst developing the new skills, tools and techniques to deliver distribution system operation functions and activities. RIIO-ED2 is an important period of transition and system and network operators should be allowed to develop within the framework set out by the regulator with those companies continually striving to deliver efficient outcomes, as agreed with their customers and stakeholders, through innovation being rewarded.

RIIO-ED2 may also be a levelling period. Customers' needs and associated network issues have occurred quicker in some regional areas, such as PV in the South West, driving the implementation of active network control there in advance of areas with lesser customer uptake of DG. It would be inappropriate to consider industry restructuring until all DNOs have had the opportunity to evidence their capabilities, and it may not be necessary to separate all DSOs from DNOs as some companies may be performing more effectively for customers than others.

Q18 Do you agree with our proposal to use the Business Plan Incentive to encourage companies to reveal standards of performance higher than our baseline expectations in their DSO strategies? Do you agree we should require, where appropriate, all DNOs adopt these revealed standards?

We support the proposed approach to include the DSO strategy elements of the Business Plan submission within the Business Plan Incentive (BPI). This will drive companies to include challenging proposals to undertake the new DSO roles and, where appropriate and supported by customer and stakeholder evidence and preferences, exceed the baseline expectations as outlined by Ofgem.

Caution should be applied where companies submit deliverables and outputs that exceed baseline expectations and where these are considered for wider adoption by the industry. This could undermine customer and stakeholder engagement if incorrectly applied. There are distinct regional differences between DNOs which will mean that the pace and nature of DSO transition will differ. It has already been seen that where some DNOs have excelled within integrating new/extended DSO functional activities, driven by the particular needs of their stakeholders, others have not yet seen the underlying driver for these functions to be developed into BAU. Due consideration should be made that DNOs should aspire within their Business Plans to transition to integrate enhanced DSO functionality at a pace which meets their stakeholders needs and should not overdeliver for the sole purpose of keeping pace with other DNOs, thus resulting in inefficient investment.

Additionally, one element cannot be pulled out in isolation as plan costs and outputs are interlinked. It would be inappropriate to simply apply or increase standards without consideration of the impact of costs to deliver those additional performance standards. Costs from one DNO cannot be assumed to be applicable to other DNOs, as some DNOs are already needing to adopt more advanced operations and have a different starting point, for example, some DNOs are further forward on development of ANM, utilising the same capacity across a range of customers using time series analysis whilst this is an emerging requirement at Electricity North West.

Q19 Do you agree with our proposal to invite companies to provide metrics and performance benchmarks in their DSO strategies?

Yes, we support the proposal for companies to provide metrics and performance standards as part of their Business Plan.

Q20 Do you agree with our proposal to introduce a DSO ODI in which we would via an ex post incentive, penalise or reward companies based on their delivery against baseline expectations and performance benchmarks? If so, what criteria and other considerations should we take into account in determining whether we should apply a reward or penalty?

We support the proposal to introduce a DSO ODI as long as the chosen metrics and performance standards support consumer outcomes, are applied consistently across the industry and are appropriate for the regional circumstances. For example; a simple metric of volume of flexibility services contracted would not be appropriate as larger DNOs and those with more constraints to solve could look positive under this metric compared to those who have capacity available to use without any funded interventions.

As RIIO-ED2 is likely a transition period for DSO we believe that any incentive framework should, at least initially, be a reward only. As experience of DSO functions and activities mature the incentive framework could be a penalty/reward mechanism with the value increased if it returns multiples of value back to customers. Generally, we would support national benchmarking of common activities. There may however need to be consideration of bespoke benchmarking for some DSO related activities per DNO where these activities are shown to not be common or when the DNO is starting from a significant advantage/disadvantage position at the start of RIIO-ED2 based on their regional requirements and/or customer and stakeholder priorities and preferences.

It is proposed the value of reward is material enough to drive network operators to find innovative ways to deliver higher performance standards over time, but again companies shouldn't be penalised for understanding and reflecting customer and stakeholder requirements and priorities which may be different to those perceived as being more pronounced needs in other areas of the UK where this is required and supported by customer and stakeholder engagement. Doing the right things for customers should be rewarded, including going at the right pace for the regional circumstances and taking proportionate actions to the scale of issues being tackled.

Reward of delivery activities should take into consideration the net benefits delivered to stakeholders, rather than simply looking to keeping pace with other DNOs. Due to regional variations in network architecture and consumer patterns there may be more requirement for some DSO functionality to be integrated into business as usual within some DNO licence areas earlier than within others. These regional differences can also generate different problems with the delivery of DSO functionality, e.g. variations in market liquidity of DERs to provide flexibility services. DNOs however should, as much as possible, be looking to standardise user experience nationally, where this is shown to be delivering best practice.

Q21 Do you agree with our proposal to undertake the ex post initiative performance assessment in the middle and at the end of the price control? Do you think the assessment should be more or less regular?

We do not support the proposal to only evaluate the DSO ODI twice within RIIO-ED2 through an ex-post mechanism.

As it is continuous improvement through well devised and executed plans that reflect our customers' and stakeholders' expectations, our preference is that the assessment should be ongoing throughout RIIO-ED2. The monitoring and reporting mechanism should be through the annual RIGs submission, accompanied by the appropriate commentary and justification.

The expectation is that there would be a reward assessment every year.

Q22 Do you have views on how we might set appropriate values for rewards and penalties associated with the DSO ODI?

Introducing a financial ODI to a new business area needs careful consideration when setting rewards/penalty values. We are attracted in principle to the suggestion within the consultation of linking the values to a percentage of costs associated as DSO as this clearly segments out from other activities and costs. However, this does assume a high accuracy of cost allocation which is unknown at this point.

We welcome further discussion on this element of the DSO framework between now and the SSMD as the proposals on DSO Business Plans develop and we have greater understanding of how the Business Plan Data Templates can work for DSO costs.

Any financial ODI should be set up with a potential reward scope sufficient to incentivise strong delivery and ensure the necessary focus and effort by a DNO. This will drive network operators to continuously develop innovative ways to deliver ever increasing performance standards overtime.

Q23 Do you agree with the DSO roles, principles and associated baseline expectations in Appendix 5? Does it provide sufficient clarity about the role of DNOs in RIIO-ED2? Do you think amendments or additional baseline expectations are required?

The additional information on DSO roles, principles and baseline expectations contained within the Appendix 5 has been useful in understanding the direction and framework development for RIIO-ED2. Without this information the network operators would have been left interpreting the DSO functions/activities provided by Ofgem in its position paper, published in August 2019. The information provided by Ofgem gives more clarity of its expectations of DSOs though we expect Ofgem will need to take consultation responses from a range of stakeholders into account and will update these roles, principles and baseline expectations in the SSMD.

Our concerns and the areas we wish to focus on are the metrics and ways of assessing DSO performance applied to the RIIO-ED2 period.

6 A Whole system approach

Q24 Are there any electricity distribution specific barriers to whole system solutions, and if so, are there are sector specific price control mechanisms to address these?

We have not identified any ED specific barriers to whole system solutions at the present time, however, we highlight the below considerations, some of which are specific to ED and will need solutions to be in place for RIIO-ED2, and others which are cross-sector considerations.

<u>ED specific considerations</u>
We agree that the approach should be broadly consistent across all sectors to ensure true whole system thinking, however it is clear that the ED sector differs from other energy sectors when considering Whole System. Whilst other sectors also face their own challenges, the combined forces of decentralisation, digitalisation and decarbonisation undoubtedly impact ED uniquely.

ED is generally affected first by external drivers where the pace of change observed on our network is faster than that observed elsewhere in the regulated energy sector. As a result, there is a continued and urgent need to engage with specific stakeholders and significant decision makers so that companies' business plans can be driven by regional aspirations, differing rates of change, development, policy and ambition. Therefore, even within DNO service areas there will be regional differences and subsequently drivers for potential of differing approaches to whole system thinking that need to be recognised and understood.

It is therefore essential that the RIIO-ED2 framework enables whole system thinking to be taken forward with the appropriate incentives, an investable regime and the funding of new activities to ensure the benefit is accrued for consumers.

Some of the potential issues facing the sector which will benefit from whole system co-ordination are still dependant on government policy. Whilst we welcome the concept of the Net Zero Advisory Group (NZAG) it is unclear precisely how this will work and what the pathway is for decisions and the implementation of such decisions. That said it should generate increased co-ordination between BEIS, other government departments and Ofgem ultimately aiding Ofgem in making price control decisions with the best possible view in this period of uncertainty.

Within the RIIO-ED2 period a flexible approach is needed from DNOs and Ofgem, where networks can learn by doing, and implement such learning to ensure continuous improvement, sharing of good practice and common approaches where these are appropriate.

One advantage of having 5-yearly price controls, with a timing difference between GD/ET and ED, is that the approach to whole system is also able to naturally evolve and can be a way of reducing barriers.

Anticipating there will be some insights within BEIS's white paper in Winter 2020/21 and certainly by RIIO-ED3, we expect to see a firm government policy decision on the decarbonisation of heat, clear direction on hydrogen development and greater exploration of the benefits of greater co-ordination across energy vectors. Therefore, we expect to see the benefits of the learning and progress made within RIIO-ED2 which will see benefit arise in the following regulatory period. Transparency on whole system decision making and governance is important for all stakeholders.

<u>Scope and CBA</u>
First and foremost, it is important that there is a clearly defined scope and ambition for RIIO-ED2, including importantly, what is meant by whole system benefits and where these accrue (i.e. with DNO customers, other sector customers, or wider societal benefits). It is important that this is in place by SSMD so that companies are better able to incorporate their whole system thinking, planning and processes within their RIIO-ED2 Business Plan proposals.

Definition of whole system activities is essential. For example, our current approach of going to the market for flexibility could be deemed as a whole systems approach because other network operators are also able to offer solutions.

Benefits in terms of lower costs to the DNO of whole system collaboration may not always be brought by an asset or flexible based solution, but rather often manifest themselves in avoided future costs or they may actually have higher costs now for the DNO, but lower whole system costs in due course. Potentially totex savings might arise and be treated under TIM as savings in a network elsewhere. Consideration of the timing of interventions, collaboration and planning are not routinely recorded or quantified by companies. It will be important to consider what Ofgem is looking for in companies demonstrating these outcomes and to what end.

It is equally important that Ofgem in its decision making, timing and stability of decisions clearly signposts where there are any impacts on whole system solutions or services which may be provided. There are a number of policy decisions on DNO participation in certain services, such as aggregation, storage or ancillary services, and it is important that any future review or areas considered which impact on whole system outcomes are signalled early and are equally well co-ordinated.

We need transparency and a clear view of compliance with the whole system licence condition, as well as fair application and material rewards linked to consumer benefits enabled.

We have stated previously that one of the key enablers for whole system decision making is the existence of a whole system cost benefit analysis (CBA) and careful consideration is needed as to what and how this is captured within a CBA model. We are seeing greater emphasis from local authorities in their CBA thinking on societal benefits and economic cost of disruption for example. We support the inclusion of wider benefits, however, as we have stated earlier in our response, companies need to have clarity and guidance as to what criteria they must consider when making their operational and investment decisions. Some options may be delivered at greater cost to DUoS customers but show net benefit to other sectors, or net societal benefits. How such decisions should be assessed and how these can feed into company business plans need to be set out as soon as possible. We recognise the positive work being undertaken by the Open Networks Whole System workstream and urge Ofgem to continue their involvement in this, including taking a more active role in its product development to ensure that the outcome is a transparent tool that networks and stakeholders can use and understand.

Finally, many details of whole system solutions are yet to be resolved as evidenced by the issues coming out from our support of the ESO's Pennine Pathfinder project. Our network currently hosts providers of services to the ESO and whilst the contract will be between the provider and ESO, our network is a vital link. Changes to the topology of our network may potentially affect some service provision from time to time. This could theoretically improve the benefits so there may be new opportunities and considerations in the way we manage and develop our network. These considerations already exist on the transmission network where the ESO may need to co-ordinate with the TO regarding service provision.

Work is underway within Open Networks to identify and ensure that the appropriate data is available to allow each party to fulfil their duty for Whole Systems consideration.

At ENWL, we continue to review and reinforce separation arrangements across the business to ensure that the teams undertaking this work are separate from other teams where appropriate.

Review of DRS mechanism
The existing Directly Remunerable Services (DRS) has been used appropriately within RIIO-ED1, however we have recently identified some limitations when it comes to whole system approaches.

There are recent examples of DNOs meeting Transmission or System Operator needs which have been arranged on a commercial basis, such as the Accelerated Loss of Mains project. It was agreed with Ofgem that DRS9 would be used to manage costs associated with the programme. However as this is a miscellaneous category which could contain a range of activities which don't naturally fit within one of the other DRS categories, it is worth reviewing the categories and potentially creating a 10th DRS category which is specifically to accommodate commercial transactions across networks. The goal would be to ensure there are no barriers to using DRS as a route where projects do not merit CAM applications. This will further support the aim of transparency and ensure activities are not mixed in with other reported costs.

Equitable cost arrangements
It is likely that networks can be the recipients of solutions from other licensees and also provide services to others. This will naturally incur additional costs as we both develop solutions for resolution of issues on others' networks, and also evaluate solutions for issues on our network from other licensees. Experience will be necessary to quantify these as well as a fair and equitable way of recovering such costs to ensure that no company or sector ends up with undue costs.

Benchmarking and cost assessment
Care should also be taken when benchmarking companies' proposals; as low cost for one company may not equate to low cost for the whole system. Different whole system solutions should ultimately be compared through the same assessment lens.

Q25 Are there any electricity distribution specific issues you think should be accounted for in the Business Plan Incentive?

We support Ofgem adding clarity for the areas under the Business Plan Incentive and we expect that more dialogue and clarity will be needed through working with Ofgem to understand what will be rewarded/penalised. Through the ENA, we have suggested a RIIO-ED2 working group meeting is dedicated to walking through the process Ofgem intends to follow in assessing the Business Plan Incentive.

As we propose in our cover letter, care should be taken to not stifle DNOs ambition by being overly prescriptive in the CVP guidance. We propose areas such as Smart Street and leading decarbonisation should be included in the list of areas to be included. This is supported by our stakeholder engagement on the SSMC where one stakeholder response specifically set out that “ENWL should take a proactive approach to supporting the North West to achieve Net Zero”.

Because the incentive currently only focusses on five areas, as per our comments above we think this might be too restrictive and therefore suggest that whilst the guidance is helpful, it should not restrict a DNO from putting forward a business plan measure that results in a reward if that measure is supported by customers and stakeholders and the company’s CEG. Any aspects not within the five specified areas will need to be fully justified from a consumer perspective as to why they are included.

Q26 Do you agree that whole system solutions are relevant to the innovation stimulus?

Yes, we agree with this approach. Without whole system thinking, collaboration and planning it may narrow the innovative solutions researched and developed which is not in customers best interests.

To ensure best value for customers in the energy system transition it is important to consider solutions which are not wholly devoted to one energy sector. For instance, in some areas it may be more beneficial to switch customers to a cleaner form of gas than to change their heating systems to an electric heat pump but in other areas the reverse may be true.

Q27 Do you agree with our key proposals for the CAM?

As we explained in our recent response to the DD consultation, we believe that it is essential that whole systems outcomes are, as a minimum, not precluded by regulatory arrangements and, where appropriate, should be strongly incentivised to ensure that all network companies are focussed on delivering the most optimal outcome for all relevant consumers.

From discussions with Ofgem we are anticipating that the Co-ordinated Adjustment Mechanism (CAM) is designed as a back-stop solution to be used in rare circumstances rather than one expected to be used commonly as fully formed plans should be developed by companies including consideration between all stakeholders as to which outputs and allowances should be set.

The approach Ofgem has taken in DDs by excluding any uncertain investment, instead preferring the use of uncertainty mechanisms means that the CAM is even less likely to be used as only those certain costs and projects are allowed in baseline expenditure. This results in the likelihood of another network being able to offer a whole system solution to the overall benefit of customers being even lower.

In light of this, and the potential complexity of the CAM and its timings, we believe Ofgem should consider whether there is sufficient justification for the inclusion of this mechanism within RIIO-2. If Ofgem does decide that the mechanism is required, we believe it should be developed bilaterally with companies. This is contingent upon Ofgem retaining the view that CAM is a mutual company consented mechanism where this is triggered by a single company.

Consideration needs to be given to projects identified within company plans, or that emerge within period where a whole system solution is identified but due to the wider use of UMs no licensee has the ex-ante allowances/output obligation to be able to transfer it. A licensee triggering the UM to receive the funding adjustment in order to then transfer it to another licensee appears impractical. Therefore there is a need for some method whereby the company delivering the solution is able to have its revenues and outputs adjusted to take into account the new obligation. As it is currently designed the CAM is not able to do this with its prime purpose being transferring revenue and outputs from one licensed entity to another. The Net Zero re-opener could be one potential solution but would need to be modified so it is able to allow companies as well as Ofgem to trigger this re-opener.

We make further comment on the CAM below:

We consider the CAM only being applicable to asset-based solutions as flexibility-based solutions, or other such services, will be managed on potentially shorter-term timescales through commercial arrangements. As we discuss in our response to Q24 the existing RIIO-ED1 DRS arrangements should be reviewed to ensure that such arrangements can be accommodated within the regulatory framework.

We agree with there being no materiality threshold, instead there is a focus on ensuring customer benefit, and we agree with the logic that companies would not progress with an application where benefits are speculative or hard to demonstrate.

Whilst we acknowledge that there will be a licence obligation (LO) on whole system co-operation and collaboration within RIIO-2, incentivisation within this area will further support the drive of focus towards whole system solutions and ensure that companies see the broader benefit of a CAM application. We support the intent of companies agreeing compensatory value associated to the risk of any transfer and that a share of any intended benefits is agreed within the commercial terms between companies when undertaking the CAM proposal. We strongly urge that guidance associated with the CAM is shared ahead of the price control commencing so that there is clarity over expectations. We also believe that greater clarity is still required on what Ofgem will consider as customer benefits and treatment where benefit falls outside of the sector enabling the solution.

We agree with the proposal of application from one licensee, with a statement of agreement with the other licensee. We also agree that this should be network triggered only as a collaboration and not required or initiated by Ofgem on one or both licensee.

We have previously stated that one of the key enablers for whole system decision making is the existence of a whole system cost benefit analysis (CBA) and so are pleased to see this being covered within the Open Networks work, as well as sector specific CBA work. It is important that Ofgem is involved in this work and considers its use within CAM assessment as companies need to have clarity and clear guidance as to what criteria they must consider when making their operational and investment decisions. Without this clarity in place and a supportive whole system CBA there is no ability to quantifiably conclude that the solution selected is the most efficient given whole system consideration.

We would add that companies have previously raised the subject of costs associated with exploring whole system solutions, preliminary studies and other preparatory work that would need to be undertaken on a routine basis ahead of any CAM application being considered necessary. We understand that the costs for any applications which go ahead would be included in the CAM, but there is also likely to be a range of costs associated with exploration of options that do not go ahead and therefore sit as aborted costs. These will be incurred by all companies as they seek to embed whole system exploration in their BAU approach however these are not costs that would have routinely been incurred in RIIO-1 and need to be considered within company's overall totex allowances. Guidance over expectations on whole system collaboration and where costs are borne by for example DNOs to support TO exploration or vice versa is required to ensure equitable arrangements are put in place.

We believe the next step in development and assessment of the CAM will be for Ofgem to stress test the CAM under a range of scenarios/case studies to see whether the issues raised in our response can be appropriately managed.

Q28 Do you consider that two application windows, or annual application windows, are more appropriate, and should these be in January or may?

Careful thought needs to be given to this question given the timing difference of the RIIO-2 period with the other sectors. The DD consultation currently considers years 2 and 4 as potential windows. We take this to mean submissions in May 2022 and May 2024 (or possibly January in line with Ofgem's proposed common position on re-openers).

In our DD response we have questioned the usefulness of a re-opener in year 4, given that any decision and resulting change in revenues will likely happen too late in the period to have any effect or allow delivery to take place. We have therefore suggested alternatives being in year 3, so May 2023.

We also see little merit in the 2026 window for ED, as this would only allow DNOs to transfer amongst their own sector, whilst GD/T will be entering RIIO-3 and any delivery via another network would already be factored into their business plans. This brings us back to our first point that if revenues and outputs are not set up-front in companies' allowances, the CAM prime objective of transferring these is not possible and another funding route needs to be explored.

The table below shows Ofgem's current DD/SSMC positions.

Network	Application Window
Transmission/Gas Distribution	May 2022 (year 2 for GD/T)
Transmission/Gas Distribution/Electricity Distribution	May 2024 (year 4 for GD/T) (year 2 for ED)
Electricity Distribution	May 2026 (year 4 for ED)

Given our view that 2024 is too late for GD/T and 2026 is limited for ED as the other sectors will be in RIIO-3, this would suggest that the window is best set the same for all sectors, as otherwise it inadvertently dictates which sector should trigger the mechanism.

Timing is probably best to be 2023 for all sectors and for anything beyond 2025 where the other sectors are entering RIIO-3 a method of adjusting the RIIO-ED2 allowances needs to be considered where a DNO is identified as best placed to deliver a project in the period 2026-2028. How the CAM works in practice can then be reviewed ahead of RIIO-3, based on experience.

Q29 Do you consider that the current electricity distribution licences should be amended to include CAM, or wait until 2023 at the start of their next price control?

We believe our proposal to place the CAM window in 2023 for Gas and Transmission would be sufficient without the need to make changes to the RIIO-ED1 licence.

7 Access Significant Code Review and Impact on RIIO-ED2

Q30 Do you agree with the impacts of our potential Access SCR proposals that are identified in this chapter? Are there additional impacts that are not identified?

The impacts listed in Table 13[12] show the potential beneficial impacts of these reforms but do not mention the associated implementation costs and downside risks. Our view of these include:

- **Review of the definition and choice of access rights for distribution users**
  As requested in the Access SCR Request for Information, depending on what is set out in the Minded-to Consultation there may be implementation costs to deliver these proposals.

- **Review of the electricity distribution connection charging boundary**
  Again, depending on what is set out in the minded-to consultation there may be implementation costs for the proposals.

  With the proposals themselves, if there is a move to a shallower connections boundary, then this would add to the uncertainty on the number of new connections that are to be expected in the price control period.

  If connection charges are recovered over time, this will have cost impacts and will also introduce a level of bad debt risk that is not a factor in current upfront connection charges and could affect financeability. Extensions assets are outside of price control so DNOs may not be able to access finance at same rates when not secured against the RAV.

  For clarity we believe changes in the connection boundary would be recovered through customers generally through DUoS. Deferred payment of connection charges would still be recovered from the person requesting the connection, except for any bad debt which we'd also expect to be recovered through DUoS.

- **A wide-ranging review of distribution network charges**
  Again, depending on what is set out in the minded-to consultation, there are likely be implementation costs associated with these proposals, with some of the more granular charging approaches likely to drive significant costs. If the implementation date is for the start of RIIO-ED2 then consideration should be given as to how any costs incurred in RIIO-ED1 ought to be recovered, e.g. through some form of logging up process.

  With the proposals, Ofgem expect that they could reduce the need for network reinforcement. Whilst this is a possibility, we do not believe there is any current evidence to support this assumption, and therefore this would add to the uncertainty on the number and the need for network reinforcement that is to be expected in the price control period.

[12] RIIO-ED2 Methodology Consultation: Overview, table 13 below paragraph 8.4, Ofgem

- **A focused review of transmission charges**
  Again, depending on what is set out in the minded-to consultation there may be implementation costs associated, particularly if DNOs are required to pass through transmission charges to suppliers or customers.

Alongside this there are potential areas of the BPDTs that could be affected are:

- 11 S1 - Performance Summary
- 34 C2 - Connections Inside PC
- 35 CV1 - Primary Reinforcement
- 36 CV2 - Secondary Reinforcement
- 37 CV3 - Fault Level Reinforcement
- 38 CV4 - NTCC
- 60 C4 - IT&T (Non-Op)
- 116 C20 - Connections Outside PC

We acknowledge that Ofgem recognises the potential impacts of the Access SCR in the Time to Connective (TTC) Incentive proposals set out in Annex 1 with potential penalties being deferred until the effect on customer behaviour is clear and we support this approach.

Q31 Do you agree with the proposed Access SCR baselines for the RIIO-ED2 business plan submissions (ie that Draft RIIO-ED2 Business Plan submissions should use Access SCR Minded to Consultation as a baseline, and that Final Business Plan submissions should use Access SCR Final Decision as a baseline?)

We agree with the proposals to use Access SCR minded-to consultation as a baseline for the draft Business Plan submissions due to be submitted to the RIIO-2 Challenge Group on 1 July 2021. We also agree with the use of the Access SCR final decisions as a baseline for final Business Plan submissions to Ofgem on 1 December 2021.

Q32 How do DNOs propose to demonstrate the impact of our Access SCR reforms on RIIO-ED2 Business Plans?

We would expect to include the estimated costs of implementing the decisions. It may be beneficial if these were separately identifiable in the BPDT. We would not propose to include any behavioural impacts of the proposals in either of the Business Plan submissions as there is limited evidence to justify inclusion. Any behavioural impacts will be picked up in the uncertainty mechanism for treatment of strategic investment (UM) as Ofgem refer to in Appendix 3. For example, the connection charge proposals could affect the volumes of LCT connecting and the DUoS proposals, as well as the amount of spare capacity in the system. It is not appropriate to have a separate UM to deal with the Access SCR specifically, though the capacity volume driver mechanism (for example, as illustrated in Figure 7[13]) needs to reflect that in some areas price signals may have reduced capacity, but this wouldn't mean that reinforcement in other areas is not justified.

[13] RIIO-ED2 Methodology Consultation: Overview, figure 7 below paragraph A3.18, Ofgem

Q33 What further guidance might be required from us to allow DNOs to identify the parts of their draft Business Plan submissions that could be impacted by our Final Decision of the Access SCR?

If DNOs are required to adjust their baseline forecasts to reflect the behavioural impacts of the Access SCR proposals, then we would expect Ofgem to inform DNOs on what it believes the impacts are forecast to be, rather than each DNO producing its own forecasts. This will aid consistency in application of the impacts of the reforms and Ofgem's own confidence in what is presented in business plans. It will be necessary as part of Ofgem's process to predict any behavioural changes of consumers so as to assess policy options and select the optimal approach.

With regard to other impacts, it is very much dependent on the nature of the changes between the minded-to consultation and the final decision. If there are significant changes to the connection boundary proposals this would have the biggest impact and may require the financial aspects of the plan to be revisited as it could significantly affect cash-flow forecasts. In terms of the other aspects of the proposals, if the behavioural impacts are addressed through UMs, then the main impact is on the timing and cost of implementation. We would expect the final decision to contain very clear proposals on the implementation solution and timescales so that more thorough costs can be determined and reflected in the Final Business Plan submission.

8 Impact of COVID-19 on the price controls

Q34 Do you think we need specific mechanisms in RIIO-ED2 to manage the potential longer-term impacts of COVID-19? If yes, what might these mechanisms be?

A global event with the impact that COVID-19 has had is unprecedented. The timing of Gas and Transmission business plan submissions in December 2019 means that these plans won't have been able to reflect COVID-19 impacts.

In operating our ED business, at the time of this response in September 2020, we are still assessing the medium and longer-term implications of COVID-19. In the short term, through the COVID-19 restrictions, we have found through our agility, the commitment of our workforce and supply chain and by listening to stakeholders and customers that we have been able to continue to provide a high standard of service, throughout the period to date. We have also continued, in response to customer and stakeholder needs, to provide new connections where safe to do so as well as sustaining the delivery of our maintenance and resilience programmes of work. We took the view from the start of the COVID-19 restrictions that safety of employees and the public is paramount, but also our vital services would be even more critical, especially if COVID-19 impacts on our customers continues into the winter months.

Inevitably, whilst focussing on customer needs, the rapid changes we made to our business to ensure that vital services continued as seamlessly as possible have led to an increase in costs, for example, simple changes we've made, like how we now use both our existing company vehicles and staffs own cars paid company mileage so that staff going to fix power cuts don't travel together for extended periods. We have also been doing different mixes of maintenance work as certain jobs offer better ability to protect the public and our workforce social distancing compared to the most efficient, optimised programmes we would normally undertake. Under the RIIO-ED1 Totex Incentive Mechanism the increased costs are shared with customers and shareholders. At the scale these costs to date have been incurred to date we don't currently think action is needed by Ofgem in our current price control to address any shortfalls in allowances. It is too early to say even now what the enduring impacts might be on our costs and service levels. For example, it is unclear to what extent we will return to the, “old pre COVID-19 normal”. In our case, as an ED company, our separate process is running about 2 years later. So we expect to be able to more effectively assess and evidence the medium and longer-term impacts of COVID-19, if material enough on our business, and reflect these into our final business plan in December 2021. A decision on in period mechanisms may still need to be made based on the circumstances.

More widely, the working between Ofgem and network companies in response to the pandemic outbreak and subsequently towards supporting customers has been an exemplar of how regulation can work under the RIIO-1 framework. It is important that the overall package in RIIO-2 is mindful of the successes of RIIO-1 for customers and does not impede the decisive and customer focussed actions companies took to protect delivery of vital services, at additional cost, without recourse to Ofgem in advance. RIIO-2 might include no flexibility in the settlement for companies and is much more focussed on companies making cases to Ofgem for new customer and stakeholder requirements and if new risks come to pass. This could be a problematical way to work in the event of similar or repeat COVID-19 type situations in RIIO-2, as Ofgem may be required to take rapid and decisive action directly to enable companies to respond as they have in RIIO-1.

When Ofgem undertakes cost assessment, target setting and benchmarking it should carefully consider the 2020/21 fiscal year, and any subsequent COVID-19 affected year(s), if the situation is prolonged. Additionally, Ofgem should ensure that appropriate indices for changes to costs during the price control are reflective of network company cost changes. The energy networks sector provides essential services and has largely continued through the pandemic. Reference indices for costs might place too much weight on other sectors that have responded differently and have latent capacity in them due to COVID-19. We request Ofgem does not use an unrepresentative index influenced by sectors that have had a down turn and probably therefore won’t have the same cost pressures as energy networks. Additionally, ways of working might be altered that affect productivity levels now and the scope to drive future productivity improvements might be impacted. Indeed, the energy sector will likely see relatively more price pressures than much of the rest of the economy as the energy sector offers the opportunity to build back better, investing in infrastructure for long term societal and consumer benefit that commences work to address the decarbonisation challenge through a green recovery. Our stakeholder engagement on this consultation echoes this, with one stakeholder specifically stating that “*ENWL should focus on what it can do to enable and accelerate the Green Recovery.*” Therefore, general indexes and measures of cost are likely to diverge from energy sector costs due to the COVID-19 shocks different impact to each sector. To the extent that Ofgem agrees costs through uncertainty mechanisms during ED2, these cost submissions can take COVID-19 impacts into account as they are made, meaning that it is the base costs most susceptible to COVID-19 change that Ofgem and companies need to consider how best to do any necessary adjustments.

electricity north west

Bringing energy to your door

Sector Specific Methodology Consultation response

Annex 2: Value for Money

September 2020

Contents

1 Approach to setting outputs and incentives

Q1 Do you agree with our proposal for setting upper and lower limits on the value of bespoke ODIs?

Questions 1 and 2 need to be considered in the context of what is 'bespoke' and what is 'standard'. It could be that there are limited 'bespoke' proposals if the 'standard' ODIs and PCDs are suitably wide-ranging as well as reflecting DNO and wider stakeholder discussions in working groups.

This would lead to bespoke proposals being targeted and reflecting specific aspects of stakeholder engagement unique to that DNO, such as Smart Street, an innovative approach developed by ENWL, but now at a technological readiness level and proven innovation that it is ready to be rolled out by any other DNO seeking to bring benefits to their consumers, thus putting enhanced stakeholder engagement and local/regional views at the heart of business plans.

The balance of incentives for RIIO-ED2 will need to be gauged carefully. We do, however, believe that a regime with strong incentives for companies to improve outcomes, drive innovation and deliver efficiencies is in the best interest of consumers and stakeholders.

As a core regulatory principle, having strong incentives is in customers' interests where they deliver additional services that customers value, so long as this is at a value that customers are willing to pay for. Rewarding companies through these incentives is wholly appropriate and reveals benefit for future price controls, which is even more relevant in a five-year price control cycle. Furthermore, incentives can provide a mechanism to fund improvements where risk is transferred away from customers who only pay for successful outcomes, rather than unsuccessful attempts to deliver outcomes.

Therefore we broadly agree with the proposal, but would suggest that where a bespoke proposal is deemed to be applicable for all DNOs the upper limit doesn't apply. It would seem sensible in the situation where an ODI which is deemed to have the ability to drive improvements for all customers and consumers is proposed that the upper limit is removed, ensuring that the full benefit for all stakeholders can be realised. The application to all DNOs should include additional comparative data that should alleviate the concern set out by Ofgem where "*the upper value should recognise… that these bespoke outputs are likely to be newer and novel output areas with no significant track record*"[1]. Additionally, a lower limit only approach would be consistent with that being proposed for PCDs.

Q2 Do you agree with our proposal for a minimum value for bespoke PCDs?

As with Q1, Q2 needs to be considered in the context of what is 'bespoke' and what is 'standard'. It could be that there are limited 'bespoke' proposals if the 'standard' ODIs and PCDs are suitably wide-ranging as well as reflecting DNO and wider stakeholder discussions in working groups.

This would lead to bespoke proposals being targeted and reflecting specific aspects of stakeholder engagement unique to that DNO, such as Smart Street, an innovative approach developed by ENWL, but now at a technological readiness level and proven innovation that it is ready to be rolled out by any other DNO seeking to bring benefits to their consumers, thus putting enhanced stakeholder engagement and local/regional views at the heart of business plans.

[1] RIIO-ED2 Sector Methodology Consultation: Annex 1 - Delivering value for money services for consumers, paragraph 2.11, Ofgem

We agree that practically a minimum value is required but would question £15m which appears to be an arbitrary value. As well as a financial minimum value to consider for PCD eligibility, there is also the consideration of what type of work lends itself to a PCD assessment, i.e. is the need, scope and method of delivery set, and is it outcome or output focused. All of these factors need to be taken into account when setting PCD eligibility criteria.

Ofgem also needs to consider how proposals that fall below any financial threshold set are treated as part of its assessment of cost. Companies should not be inadvertently penalised for committing to deliverables that are valued/prioritised by customer and stakeholder engagement but fall below this arbitrary threshold and are not homogeneous between all DNOs. This is of upmost importance where enhanced stakeholder engagement and views are central to DNOs business plans and where these regional/local views and priorities have been well established and justified.

Finally, we note that this question is specifically about bespoke PCDs however there is no reference in the consultation, or any questions relating to, common sector-wide PCDs which we believe is a gap in the consultation. We ask for clarification as to the type of activity and value threshold that Ofgem considers to be appropriate for PCDs within the ED sector and that this clarity/Ofgem's thinking is shared with networks during the working groups and made clear within the forthcoming decision.

2 Meet the needs of consumers and network users: Customer satisfaction

Q3 Do you agree with the proposed scope and associated customer category weightings for the satisfaction survey?

We think the customer satisfaction survey has been an effective incentive in delivering improvements across all DNOs. We support the separate reporting of PSR customers who experience a supply interruption as we would expect their experience to be enhanced due to the efforts made in dealing with customers who are vulnerable and we understand the linkages to the new licence obligation.

The rationale for separate reporting of LCTs is less clear. Currently the incentive applies to all equally and makes no distinction between the type of customer. By separately reporting these activities it is not clear what, if any, performance is expected by Ofgem; should it be broadly the same or different, and if different, how? This is of importance as LCT uptake in the foreseeable future is more likely to be taken up by more affluent customers. This could lead to differentiated services that are at odds with the principles covering and identifying blockers to vulnerable customers participating in a smart flexible energy system.

Particularly in relation to interruptions the categorisation of an LCT customer would not be easy. For connections and general enquiries, the nature of the customer can readily be ascertained as they indicate what service they require. For interruptions we would need to ask the customer off supply additional questions. This could imply a differentiated service to them if they do have, for example, an electric vehicle and could mean that they may provide inaccurate information if they anticipate their supply will be restored more quickly.

We consider that the category weights are broadly appropriate.

We note that this part of the document refers to the financial exposure in terms of percentage of base revenue. We assume that the actual calculations will be based on RoRE basis points for consistency, and to support all stakeholders in understanding the framework, urge that all incentives are expressed in RoRE terms. This is especially important given the proposal to implement a RAM in RIIO-2.

Q4 Do you agree with our proposed approach to target setting and calculating rewards and penalties in RIIO-ED2?

We understood that in RIIO-ED1 Ofgem used upper quartile (UQ) performance on the UK Customer Satisfaction Index as a "*sufficiently challenging, but achievable target*" to "*ensure that only those that provide a level of service that would be considered good in comparison with any other industry will be rewarded*" rather than a limitation of historical data[2].

We think this approach of using an external benchmark still has merit, particularly as there are several factors which would mean that historic DNO performance is not a good indication that these performance levels can be sustained. These include:

- Customers are becoming more reliant on their supply of electricity due, as Ofgem notes, to the increased uptake of LCT, but also due to the increased homeworking initiated in response to COVID-19.
- Many companies are now looking at their use of office space and the indications are that more will utilise increased levels of homeworking. Some have even moved to that as their default way of working.
- The economic outlook has a looming recession, and this can result in declining levels of customer satisfaction.

We think that the results for this current year should be removed from the calculation of UQ performance. The current levels of customer satisfaction are very high, but we believe that this is a result of the general appreciation of "key workers" during the pandemic. We do not think this short-term improvement in satisfaction is representative and has the potential to set the UQ performance based on Ofgem's proposed approach. We therefore suggest that this year's data is removed for the purposes of setting the targets. Note as the performance is above the maximum reward, DNOs are getting no additional benefit from these higher scores.

We think the introduction of a deadband is a sensible idea to ensure that good performance is not financially penalised. Due to the potential increased expectations from customers we do not think that setting the penalty threshold based on average performance is justified. This could result in targets that result in penalties when performance is better than best in class performance measured by UKCSI (currently 85.3)[3]. The top ten in that index have a score of 82.9 and we think this could be used as a challenging threshold for financial penalties to start.

We strongly support the retention of static targets. These allow DNOs to develop business plans for improvements as the potential improvement in scores can be evaluated against the costs to achieve this and consumer priorities. This has facilitated greater sharing of best practice and been a key feature in allowing us to improve our satisfaction scores across all three categories.

[2] https://www.ofgem.gov.uk/sites/default/files/docs/2013/09/riioed1_custservice_connection_incentives_open_letter_040913.pdf

[3] https://lp.instituteofcustomerservice.com/ukcsi-july-2020

Q5 Do you agree with our proposed approach to setting complaints metric targets in RIIO-ED2?

We support the majority of the proposed approach as we think this has focused DNOs to improve the service provided. We think that the target set for gas is a useful comparator and therefore think a score of four would be appropriate.

Additionally, one of our stakeholder responses as part of our engagement on this consultation agreed that "Option 1 [is] preferable."

Q6 Do you agree with our proposal to remove the Stakeholder Engagement and Consumer Vulnerability Incentive in RIIO-ED2?

Yes, we agree that this should be removed. We believe that this mechanism has been a contributory factor in the lack of convergence in performance identified in paragraph 6.7 of the consultation. Stakeholder Engagement and Consumer Vulnerability (SECV) has been seen as competitive and this has deterred collaboration and sharing of best practice. The feedback mechanism has not clearly identified areas of best practice to encourage uptake by other DNOs.

3 Meet the needs of consumers and network users: Connections

Q7 Do you agree with our proposal to expand the connections element of the customer satisfaction survey?

The principle of defining the different categories of connection, and their alignment to market shares, has been used throughout connections activities. The category defines many aspects; the standards that apply, the type of margin that applies, the timescales for Guaranteed Standards and the reporting categories for RRP. Any changes to the categories will therefore need to be cascaded through a number of governing documents including the Licence, RIGs and statutory instruments. So, whilst it is possible, our view is that changes should not be made lightly without consideration of the consequential impacts to keep this clear alignment.

The proposal is not clear whether the proposed expansion of market segments into the customer satisfaction survey would apply to all DNOs or only to market segments that had not passed the Competition Tests.

We think that competition acts effectively to ensure good customer service and consider that market segments that have passed the Competition Tests should not be included in the customer satisfaction survey. This also removes the risk of distorting competition if rewards were available to DNOs, not funded by connections customers, that are not available to third parties.

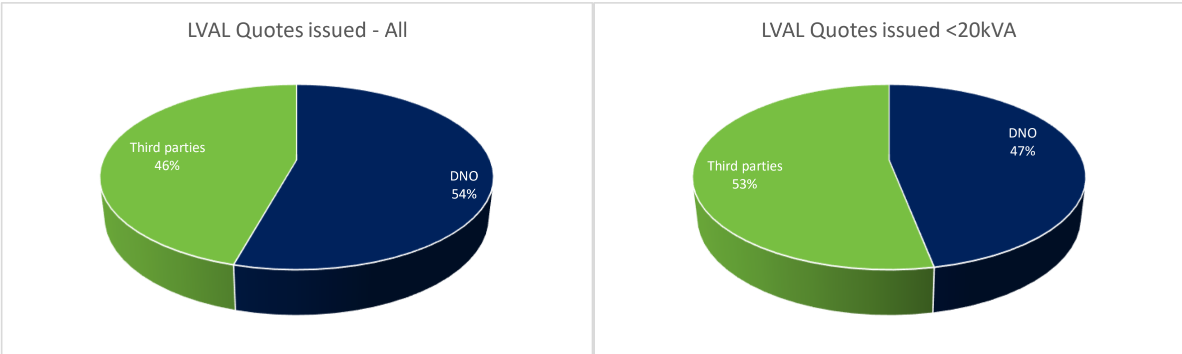
If only market segments that did not pass the Competition Tests go into the customer satisfaction survey, then this will need to be considered in both target setting and reporting. The table below shows the number of licences that passed the 2013 Competition Test. There may be a need to differentiate targets depending on the range of customers that are in scope. Whilst this is not insurmountable, it does add complexity.

Figure 1: 2013 Competition Tests outcome by licensee

	Passed	Not passed	% passed
LV	2	12	14%
HV	4	10	29%
DGLV	0	14	0%

In our experience both the LVAL and LVHV market segments have active competition. The level of competition is active even at the smaller end of these market segments. For example, the two charts below show data for the connection offers we issued in the 2019/20 regulatory year. This shows the active competition in the whole market segment where 46% of the connection offers we issued were to third parties. Looking at a subset of these, where the requested capacity was less than 20kVA (average would be over 100kVA) shows even greater levels of competitive activity. We share this analysis to show that a simple hypothesis that there will be less competition at the lower end of a market segment may not be reality. We therefore urge caution in making any changes to the well-established market segments.

Figure 2 and 3: LVAL connection offers issued during 2019/20



In our experience the DGLV market segment is small both in terms of volume and value. In 2019/20 we issued fewer than 300 connection offers and, as shown below, the clear majority of these were 'nil value quotes' where no work was needed to allow the connection of the distributed generation equipment, typically to existing premises.

Figure 4: DGLV connection offers issued during 2019/20

Due to the small volumes and value of the work we see less competition in this area. However, we consider that these customers are best served by having specific incentives that address their needs. If they were incorporated into the customer satisfaction survey, we believe that that this might be less beneficial than having their specific needs addressed as they would be a small proportion of the survey sampled based on the relative volumes.

Q8 Do you consider that we have identified the relevant considerations to determine which customers should be captured in its scope?

We think that the alternative mechanisms set out in the document should also be considered as an alternative to competition or inclusion in the customer satisfaction survey.

Q9 Do you agree with our proposal to retain the TTC incentive as a financial ODI in RIIO-ED2?

We have put significant focus and effort into making improvements to both our time to quote and time to connect, restructuring our organisation, investing in IT and making improvements to our processes and systems. This has allowed us to deliver consistently good, sustained performance in both measures. This performance will not be maintained without continued focus and therefore we can see merit in the TTC incentive being retained. However, we have a number of concerns regarding the proposed changes that are covered in our responses to Q10 and Q11.

We also note that this part of the document refers to the financial exposure in terms of percentage of base revenue. We assume that the actual calculations will be based on RoRE basis points for consistency, and to support all stakeholders in understanding the framework, urge that all incentives are expressed in RoRE terms. This is especially important given the proposal to implement a RAM in RIIO-2.

Q10 Do you agree with our proposal to include a reopener which allows us to revisit targets, and potentially introduce penalties, in the period?

We disagree with the proposals to include a re-opener and to potentially introduce penalties.

The proposal to introduce a re-opener that can be instigated on an arbitrary basis without any defined criteria simply creates regulatory uncertainty and undermines the incentive properties. Clear and static targets have had demonstrable benefits during RIIO-ED1 and give a firm basis for DNOs to invest in improvements as the benefits can be assessed. An arbitrary re-opener is likely to dissuade the better performing companies to try to make further improvements as the benefits case could get undermined. Companies that are performing less well might also not try to improve if they perceived that the targets could be reset even further out of reach.

Ofgem's stated intention in paragraph 5.24 of the consultation, to "*tighten targets if they are easily outperformed*" runs counter to the experience of TTC to date. Whilst overall TTC has improved performance across all the DNOs there is still a range in the performance observed. There are several companies like ourselves that deliver consistently good performance, but this performance is not without significant effort and has delivered improved timescales that customers benefit from. The fact that the performance is not consistent suggests that these targets are not easy to outperform. In our view the opportunity for further improvements is limited. Both parts of the incentive rely on customer behaviour and particularly for TTC we are often limited in our ability to further improve timescales because customers do not want the connection any faster. The incentive is measured from when the customer accepts to when they are connected, and this timescale is more often determined by the customer's programme than by any limitation on our ability to make the connection.

We also disagree with the proposal to introduce penalties. As discussed above, there are limitations to the improvements that DNOs can make in these two aspects as they are largely driven by the preferences, priorities and choices of customers. Ofgem notes this in its rationale for not allowing exemptions. We can accept this rationale of no exemptions if TTC remains as a reward only mechanism. However, if penalties were to be introduced then we believe that the mechanism would need to change to ensure that DNOs have an appropriate level of influence on the performance and that underlying performance isn't adversely affect by factors outside management/DNO control. This could be achieved for example by measuring the time from when the site was ready for the connection to when the connection was made. We recognise that the targets would also need to be recalibrated on this basis but this would be more appropriate should a symmetrical incentive regime be desired.

Applying penalties to a company whose performance deteriorates without consideration of the level of performance also seems unreasonable and could have unintended consequences. This approach would create a disincentive to improve the service to customers as it introduces a risk that if that performance is not maintained it could lead to a financial penalty. It also introduces more risk to companies that have performed well as any deterioration would be penalised. Companies that have not had good performance are less at risk as it is easier to make marginal improvements from a lower performance base. It would seem a perverse outcome for a company that has performed well to be penalised financially for any deterioration in its performance whereas a company that had not previously performed well is rewarded for improvements but with a lower performance level.

Q11 Do you agree with the methodology we propose to use to set the new TTC targets?

The proposal is not clear whether the proposed expansion of market segments into the TTC would apply to all DNOs or only to market segments that had not passed the Competition Tests.

We think that competition acts effectively to ensure good customer service and consider that market segments that passed the Competition Tests should not be included in TTC. This also removes the risk of distorting competition if rewards were available to DNOs, not funded by connections customers, that are not available to third parties.

If only market segments that did not pass the Competition Tests go into the customer satisfaction survey, then this will need to be considered in both target setting and reporting. We believe separate targets would be needed for both the Time To Quote and Time To Connect aspects should any additional customers be added into the incentive.

As we described in our response to Q7, having different treatment for subsets of market segments undermines the clarity of treatment based on the project classification. We therefore do not think that including part of a market segment is a good idea as it would require changes to systems and reporting that are not necessarily beneficial overall. The introduction of additional market segments into TTC is likely to increase the range of types and durations of connections and potentially mean that a DNO's performance is more influenced by the type of work mix that it undertakes. This means a single target based on the average of DNOs may be less appropriate as the performance of the DNO may be more impacted by the different mixes of work undertaken due to differences in networks etc.

The proposals on TTC also introduce the risk of distorting competition if rewards were available to DNOs, not funded by connections customers, that are not available to third parties.

We agree that the average DNO performance should be used to calculate the minimum reward. We think that the target should be calculated in advance of the start of RIIO-ED2. This could be achieved using the performance data up to and including year seven for the calculation.

We are unsure how the proposed 'hockey stick' scale for the incentive would work. It adds additional complexity to the calculation of the incentive and therefore the evaluation of benefits for developing improvements.

Q12 Do you have views on our proposed Connection Principles and associated standards (in Appendix 4) for RIIO-ED2? Do you disagree with any of the standards we have proposed? If so, why?

The principles, and associated standards, cover many aspects of connections activity that already happen. It is not clear what deficiencies have been identified by stakeholders that need further attention. It is also not clear how the assessment against these standards would be carried out; they are descriptions of activities rather than explicit standards. It is not immediately obvious how these would be translated into "*metrics and ambitions targets*" as described in paragraph 5.51 of the consultation. Our concern therefore is that the assessment would be a very subjective assessment and lack the necessary transparency to DNOs and stakeholders. We think the standards need further development work as many would not be applicable to all market segments, for example any of the unmetered market segments.

Q13 Do you have views on our proposal to use the Business Plan Incentive to encourage companies to reveal higher baseline standards of performance and to apply this, where appropriate, to all DNOs?

We think the proposal creates a perverse incentive and disadvantages companies that have actively supported competition in connections in the past.

The framework appears to mirror some of the principles that applied to ICE, but we believe it would introduce some additional new issues. Paragraphs 5.43 and 5.57 of the consultation suggest that the new approach would only apply to market segments that did not pass the Competition Tests. Consistent with the principles of ICE, this means that DNOs have a reduced risk of penalties where they had demonstrated that there was active competition.

The funding of connection strategies through allowances (paragraph 5.53 of the consultation) could potentially introduce some cross-subsidy issues and a potential distortion of competition as this funding is not available to third parties competing in these market segments. This approach also appears to be counter to the broad approach of seeking to keep customers bills down as it would increase the funding from DUoS customers rather than from the connecting customers that benefit.

Similarly, the introduction of rewards creates potential opportunity for funding that is not available to third parties competing in these market segments therefore again potentially distorting competition.

The approach would appear to be disadvantageous in many aspects to DNOs that were more successful in the Competition Test. Companies that were less successful:

- Would have greater reward opportunity (albeit with symmetrical penalty risk)
- Would have funding that could result in higher allowances and more opportunity for outperformance though the TIM

- Would have funding for initiatives (through allowances) that do not increase the costs to connections customers, thereby keeping their costs down and making it harder for third parties to compete against the DNO

Stakeholders are likely to expect all DNOs to make similar improvements to those that have been funded through allowances via the connections strategies in business plans. Other companies will come under pressure to provide these but without access to the same funding. Having to provide these improvements and pass the costs onto their customers will make them less competitive and therefore adversely impact the DNO's ability to win work.

The utilisation of the Competition Tests in the framework should in our view be refreshed to take account of a more contemporary view of competition. We believe that a review of competition through analysis of the proportion of connection offers issued and accepted could give an appropriate indication of the levels of competition that now exist. The establishment of the Competition in Connections Code of Practice has embedded best practice and therefore there is less need to consider the process aspects in the assessment.

Overall greater clarity is needed on how the proposed mechanism would work. The approach describes that information in Final Business Plans could be used to alter baseline standards for all companies. Such a late change to requirements without consideration of, and revisions to, funding does not seem an appropriate approach. Additionally, "*consistent and high-quality connections strategies*"[4] are encouraged which appears to conflict with the reward mechanism through the CVP process that requires unique propositions that raises the standards of other DNOs.

Q14 Do you agree with our proposal to use an ex post assessment to penalise/reward companies who fail to deliver their strategies in line with our guidance/exceed performance targets?

The interplay between how Business Plans are assessed and rewarded and how the ex post assessment would work needs further clarity. From the description, DNOs could be rewarded through the BPI for ambitious plans but only if they are used to improve the baseline standards for all companies. If a company proposes something in its plan that is higher than the standard but does not meet the criteria for a BPI reward through the CVP element, then what performance is the DNO held to account for?

Whilst the approaches described may work in theory we are concerned how they would work in practice in relation to connections activities. As the articulation of the standards is not precise, our concern is that the assessment would be very subjective.

We also believe that the incentive rate needs to be determined prior to Business Plans being submitted. DNOs should not be expected to develop connections strategies in their Business Plan where the level of incentive could change. This uncertainty could be detrimental to Ofgem's desire for ambitious Business Plans if the potential rewards could be removed at Draft or Final Determination.

We consider that the introduction of rewards introduces a potential for distortion of competition.

[4] RIIO-ED2 Sector Methodology Consultation: Annex 1 - Delivering value for money services for consumers, paragraph 5.44, Ofgem

Q15 Do you consider that an assessment of performance in the middle and at the end of the price control is a proportionate approach?

The appropriate timing for the in-period assessment is unclear. As Ofgem recognises in paragraph 5.55 of the consultation, the impact of service improvements may take some time to become demonstrable. As many of the initiatives will not start until the beginning of RIIO-ED2, then any assessment prior to the end of the third year may be premature. This would also coincide with work on ED3 and therefore create an additional burden rather than reduce it. By the time the assessment process has run, it also allows very little time for the DNO to respond before the final assessment.

An assessment part way through the period without a decision on penalties or rewards does however have merit and provides an opportunity for DNOs to receive clear feedback on Ofgem's view of their individual performance. The form of feedback from this review should be agreed in advance so that it provides clarity, reasons for views and clear expectations for the remainder of the period. It is practical for the final decision to be made at the end of the price control period. An ex-post review is not without challenge however, and also constitutes additional risk for companies. It would require the assessment process to be clearly set out upfront and be undertaken in a transparent way to give confidence to all stakeholders of the outcome of the process. If stakeholder feedback forms part of the assessment, then it is likely to be influenced by their most recent experience rather than an objective view over the five-year period.

Q16 Do you agree with our proposal to retain the Connections GSoPs for all connection customers in RIIO-ED2?

We agree that the connections GSoPs should be retained. These cover the key aspects of connections and the timescales provide suitable back-stop guarantees for customers.

Q17 Do you agree with our proposed approach to uplifting the Connections GSoP payment values in line with inflation, indexing payment levels to inflation, and rounding to the nearest £5?

We agree that the payments should be increased in line with CPI(H) as this is to be used elsewhere in the price control as the measure of inflation. It is not clear in the proposal as to the frequency of the review and updating. We are not against this happening on an enduring basis, but the details of the mechanism would need further consideration for codifying in the statutory instrument and/or licence.

Q18 Do you agree with our proposal to remove the Incentive on Connections Engagement for RIIO-ED2?

We believe that ICE has been an effective mechanism to significantly enhance the quantity and quality of stakeholder engagement. It has also driven significant improvement in services to connections customers. As outlined in previous responses, we are not fully clear on the proposed replacement mechanism and have identified some concerns, therefore we are unsure whether the proposed new mechanism is a better alternative for stakeholders.

4 Meet the needs of consumers and network users: Vulnerability

Q19 Do you agree with our proposed approach to ensuring consumers in vulnerable situations receive an appropriate range and level of support in RIIO-ED2? If not, what alternative approach should we consider?

We believe that the proposed approach will deliver better, and more consistent outcomes, for vulnerable customers. Funding through allowances gives greater cost certainty and allows longer-term initiatives to be developed, whilst also retaining appropriate incentivisation to deliver the services more efficiently.

One limitation of the proposed approach is that the funding is limited to initiatives developed through the Business Plan process to address the baseline standards. We still believe that there is merit in having additional, capped, 'use it or lose it (UIOLI)' funding available for new activities that emerge after the Business Planning process and where there is demonstrable social value. We believe that the common social return on investment (SROI) model being developed by the DNOs could be utilised, and criteria developed to safeguard the use of this funding.

Our stakeholders in the North West have made it very clear through our business plan engagement that additional support for those in vulnerable circumstances and those in poverty is required. Therefore as referenced in our covering letter and set out in more detail in our response to Q25 of the Finance annex[5], we have proposed that the Return Adjustment Mechanism (RAMs) be modified to support customers in vulnerable circumstances.

Additionally one stakeholder stated as response to our engagement on this consultation that it would "expect [the need for DNOs] to adapt vulnerable customer support strategies for the socially distant environment that we face for the foreseeable future and to develop its understanding of the nature of new vulnerabilities brought about by COVID. It is likely that some customers now in vulnerable circumstances, would not have been considered vulnerable prior to the pandemic."

We also believe that the incentive rate needs to be determined prior to Business Plans being submitted. It is not reasonable for DNOs to be expected to develop vulnerability strategies in their Business Plan where the level of incentive could change. This uncertainty could be detrimental to Ofgem's desire for ambitious Business Plans if the potential rewards could be removed at the Draft or Final Determination stages.

Q20 Do you have views on our proposed Vulnerability Principles and associated standards (in Appendix 5) for RIIO-ED2? Do you disagree with any of the standards we have proposed? If so, why?

We think these act as a good starting point to ensuring good and consistent levels of performance.

We note that the level of effective PSR database maintenance is defined as every 24 months. Based on feedback from our stakeholders, for some lower risk categories such as older customers with no other issues, we currently update this every 36 months. The proposed mechanism appears to give appropriate flexibility for us to either increase the frequency of these categories or justify the current frequency.

[5] Annex 4 of this consultation response

The measurement of this activity also needs to be based on the frequency of the DNO seeking to validate the data, rather than the data being validated. This will avoid the creation of a perverse incentive that drives a DNO to make repeated attempts to contact that become excessive from the perspective of the PSR customer and could add to their vulnerability.

Q21 Do you agree with our proposal to use an ex post assessment to penalise/reward companies who fail to deliver their strategies in line with our guidance/exceed performance targets?

As we state in our response to Q14, the interplay between how Business Plans are assessed and rewarded and how the ex post assessment would work needs further clarity. From the description, DNOs could be rewarded through the BPI for ambitious plans but only if they are used to improve the baseline standards for all companies. If a company proposes something in their plan that is higher than the standard but does not meet the criteria for a BPI reward through the CVP element, then what performance is the DNO held to account for?

In principle we agree with the approach proposed however, we are concerned that the assessment approach is not defined and could be subjective as well as lacking transparency. We think this is an area where greater clarity from Ofgem would be beneficial and would give DNOs more confidence to develop ambitious Business Plans that would benefit their vulnerable customers.

We also believe that the incentive rate needs to be determined prior to Business Plans being submitted. DNOs should not be expected to develop strategies in their Business Plan where the level of incentive could change. This uncertainty could be detrimental to Ofgem's desire for ambitious Business Plans if the potential rewards could be removed at Draft or Final Determination.

Q22 Do you consider that an assessment of performance in the middle and at the end of the price control is a proportionate approach?

We agree that the move away from an annual assessment has benefits. We are less clear on the appropriate timing of an assessment within the price control period as some initiatives may only commence from the start of RIIO-ED2 in line with the funding and may take several years to have demonstrable benefits.

An assessment part way through the period without a decision on penalties or rewards has merit and provides an opportunity for clear feedback on Ofgem's view of DNO performance. The form of feedback from this review should be agreed in advance so that it provides clarity, reasons for views and clear expectations for the remainder of the period. It is practical for the final decision to be made at the end of the price control period. An ex-post review is not without challenge however, and also constitutes additional risk for companies. It would require the assessment process to be clearly set out upfront and be undertaken in a transparent way to give confidence to all stakeholders of the outcome of the process. If stakeholder feedback forms part of the assessment, then it is likely to be influenced by their most recent experience rather than an objective view over the five-year period.

5 Maintain a reliable network

Q23 Do you agree with our proposed approach to retain the RIIO-ED1 methodology for setting unplanned interruptions targets?

We broadly agree. We agree that benchmarking on the basis of disaggregated network type is appropriate for HV and that relative benchmarking on other voltages would be overly complex. We understand the argument for introducing the 'lower of' rule in terms of DNO actual performance and results of the benchmarking approach. However we suggest that, where DNO performance exceeds the RIIO-ED1 IIS cap in the relevant year(s) used for the comparison, this cap value is used instead of actuals. It is the cap value that customers have actually paid for and any performance beyond this has been at the DNO's expense. This modification would ensure that there remains an incentive to deliver performance improvements right through to the end of RIIO-ED1, thus maximising benefit to customers of the existing scheme.

The 'lower of' assessment should also be conducted in the round, i.e. considering the overall position against IIS revenues. A company could theoretically be ahead on CIs but behind on CMLs with a combined impact of being in IIS penalty. In these circumstances it would be inappropriate to set CI targets at the lower level as the condition of customers having already paid for that level of performance has not been met.

We also seek clarity from Ofgem in terms of the time periods that will be used for the calculation of actuals and benchmarks and suggest that these should be consistent with each other to avoid cherry picking a single 'good' or 'bad' year.

Q24 Do you have views on the alternative approaches to setting unplanned interruptions targets set out? Are there any other approaches that we have not considered?

We think the main viable alternatives have been appropriately considered. We remain concerned that the application of upper quartile restoration (ASID) levels at HV to DNOs performing well on CIs in order to set CML targets risks a cherry-picking approach.

In order to ensure transparency, we suggest that Ofgem publishes the model used for target-setting so that it can be validated, and that previous and new errors in calculation can be prevented/corrected.

Q25 What are your views on revisiting unplanned interruptions targets within the price control period?

We agree with Ofgem that it is not appropriate to revisit unplanned interruptions targets within the price control period given a five-year control period and the uncertainty it causes. Resetting targets would also limit the period over which a DNO would be able to recover the benefits of investment to improve the quality of supply and hence serve to restrict the delivery of such benefits to customers.

Q26 Do you agree with our proposed position not to introduce further convergence of DNOs' targets over time?

We agree, although Ofgem needs to ensure that DNOs are not penalised for delivering better levels of performance than their peers. There is already an element of convergence in the HV element of the target setting by assigning a higher annual improvement rate to those DNOs underperforming the benchmark.

Q27 What are your views on retaining an incentive for planned interruptions performance, and the associated targets?

We think this is appropriate and aligns with our customer preferences elicited through the enhanced stakeholder engagement conducted as part of our business plan development.

We highlight that there are potentially significant influences on the level of planned interruptions in RIIO-ED2, e.g. due to the delivery of programmes to ensure compliance with the Persistent Organic Pollutants (POP) regulations. These could introduce significant volatility in performance through the period. By itself, the target-setting process for planned interruptions will equalise these over time; however, by including planned interruptions within the overall revenue cap, there is a risk that companies will not be appropriately remunerated if the unwinding of the higher levels in later years' targets coincides with unplanned outperformance causing the cap to be breached.

We therefore suggest that planned interruption performance is removed from the overall revenue cap.

Q28 What are your views on the potential amendments that could be made to the mechanism, including (but not limited to) the options presented in Tables 23 and 24?

We have reviewed the weighting of planned interruptions (set out in table 23 of the consultation) against our recent customer research and consider it appropriate to retain the current 50% weighting level. In essence, increasing customer intolerance of power cuts more generally appears to be broadly countered by the improvements in notice period and restoration information which has reduced their disruptive impact. Any other value would essentially be arbitrary unless evidenced by recent, national level customer research.

In terms of target-setting (table 24 of the consultation), we believe that the rolling process currently in operation in RIIO-ED1 is fit-for-purpose and allows the DNOs flexibility. We do observe however, that this enshrines significantly different starting positions for DNOs and suggest that Ofgem take this into account when conducting any unit cost analysis where the inclusion of generation costs (or not) may be a material distortion in the assessment of any benchmarked position.

Q29 What are your views on how VoLL should be updated for RIIO-ED2?

We agree that the VoLL value should be updated and uplifted to reflect a real term customer increase in value since it was last validated and to account for inflationary impacts. In many regards, a single VoLL value will always be a crude approximation at a point in time hence a level of estimation will be required. Updating the domestic/SME ratio to reflect current data would appear to be sensible. The

VoLL value interacts with the target-setting process and the decision on overall revenue exposure to produce the marginal rate for improvements. With lower targets, a higher VoLL and unchanged exposure (as proposed), the ranges from maximum reward to maximum penalty are likely to be tight, exposing the DNOs to increased volatility risk.

Q30 What are your views on the different methodologies for updating VoLL?

We agree that the retention of a single VoLL figure for IIS is appropriate considering that this mechanism is designed to incentivise current overall average performance. We also believe that models looking at long-term future investment options (e.g. CBA and CNAIM) should be designed to reflect an appropriately justified differentiated value of VoLL. This could be used to identify and justify targeted programmes where the enhanced VoLL of the beneficiary customers is relevant and/or to reflect the likely change in VoLL over the lifetime of an investment decision in the context of the journey to Net Zero.

Q31 Do you have a view on retaining alignment with VoLL figures used in other RIIO price controls and/or parts of the energy sector?

We agree that this might seem desirable, though would highlight that the VoLL is not static and continually evolves, hence an event of the magnitude of a price control re-set should be used as an opportunity to update this critical calibration value.

Q32 Do you agree with our proposed approach to retain the RIIO-ED1 revenue cap for the IIS at 250 RoRE basis points?

As a minimum, we agree that this is appropriate to retain 250 basis points and the incentive qualities of the IIS scheme. A greater incentive opportunity than 250 basis points would drive a greater investment in measures to improve service faster. However, how the Return Adjustment Mechanism (RAM) is set needs to be considered in the context of IIS and the overall incentives package developed for RIIO-ED2.

Further, we believe that artificially capping the upside of an incentive designed to achieve improvements that customers value and set at a rate reflecting that value is not in customers' overall interests and Ofgem should consider its removal to avoid artificially constraining performance improvements that would otherwise be possible.

Linked to our response to Q27, Ofgem should consider removing planned interruptions exposure from the capping mechanism due to the likely volatility of this measure in RIIO-ED2 and the interaction with unplanned performance.

Q33 Do you agree with our proposal not to introduce an incentive on short interruptions in RIIO-ED2? If not, how should such an incentive be structured and developed?

We agree that an incentive for short interruptions should not be introduced in RIIO-ED2.

We also agree that the focus in RIIO-ED2 should be on establishing a consistent and accurate reporting process ahead of the introduction of any potential associated incentive regime.

Q34 What are your views on a minimum standard for short interruptions for RIIO- ED2?

We believe that this proposal requires further discussion and can only be implemented once the reporting improvements noted have been implemented and thoroughly tested to ensure that an appropriate baseline can be established reflecting a suitable minimum standard.

As it is unclear whether Ofgem is proposing a new Guaranteed Standard in this regard. We also believe that the interaction of this minimum standard with any proposed future incentive regime needs to be considered further as it could be of material cost to companies and would need to be included in Business Plans.

It is therefore our position that these should not be introduced in RIIO-ED2 and should be introduced at the same time as an incentive on Short Interruptions as set out in our response to Q33.

Q35 What information should we be capturing in RIIO-ED1 and RIIO-ED2 to better understand short interruptions and how DNOs are performing?

We support the proposals that have been developed through the Ofgem Safety, Resilience & Reliability Working Group (SRRWG) to adapt a version of the current interruptions reporting template for short duration interruption reporting. This should give the relevant data to allow performance to be compared and an appropriate baseline set, once the data accuracy and consistency of reporting is at the required standard, ready for RIIO-ED3 when the case for an incentive should be reconsidered.

Q36 Do you agree with our proposal to retain the RIIO-ED1 SWEE mechanism?

We agree and think that the mechanism remains fit-for-purpose, as well as ensuring an appropriate balance of risk between companies and customers in terms of exposure to extreme weather events. Consideration should be given to ensure that it is not excessively bureaucratic to administer.

Q37 Do you agree with our proposal to remove the OEE mechanism? If not, what evidence is there to support its retention, and what changes should be made to the existing approach to improve it?

We disagree with this proposal and suggest that the OEE mechanism is retained but that its associated qualification criteria are clarified to refocus on the genuine one-off circumstances outside of a DNO’s control such as a major third-party cable strike.

Varying interpretations of its implementation within RIIO-ED1 should not be used as a reason to remove it entirely. The OEE mechanism is increasingly important as, with the tighter IIS targets likely to be proposed for RIIO-ED2, the ability of a single event outside of a DNO’s control to significantly change its IIS position is exacerbated and the exposure to risk increased.

Q38 What are your views on the threshold that should apply to either exceptional event mechanism?

For SWEE, we believe that updating the current thresholds of 8 times daily mean HV faults for Category one and 13 times daily mean for Category two events is appropriate.

For OEE, the criteria should be set with respect to the financial risk that the licensee is exposed to hence will require the size of the licensee to be taken into consideration.

Q39 What performance do you think should be excluded under each mechanism?

We believe that the criteria for the events to be excluded under the SWEE mechanism are well understood and the volume of these typical annual claims allows Ofgem to assess that these are being consistently applied.

With regard to the OEE mechanism, we agree that this should be refocused onto clearly defined types of one-off events and not used to adjust for the impact of prolonged factors.

Q40 Do you agree with our proposal to retain the existing GSoPs? If not, what changes do you think are necessary and what are the reasons for them?

We agree that the GSoP should be retained.

Q41 Do you agree with our proposal to uplift payment values in line with inflation, indexing payment levels to inflation, and rounding to the nearest £5 for clarity for stakeholders?

We agree that the payments should be increased in line with CPI(H) as is the measure of inflation used elsewhere in the price control. It is not clear in the proposal as to the frequency of the review and updating. We are not against this happening on an enduring basis, but the details of the mechanism would need further consideration for codifying in the statutory instrument and/or licence.

Q42 Do you agree with our proposal to retain some form of mechanism for WSC in RIIO-ED2?

We agree that the current mechanism does not work effectively. The process is cumbersome and delays service improvements being made until after customers have qualified against very narrow criteria. We hold this view despite being by far the most extensive users of the current scheme on a proportional basis. The low overall DNO take up rate shows how ineffective it has proved, with some DNOs appearing to ignore the scheme completely, potentially disadvantaging their customers from the benefits that could have been available.

We agree that a mechanism needs to be in place for RIIO-ED2 to ensure the needs of worst-served customers are addressed. The IIS incentive does not do this as it is based on economically-driven average performance. Further, we are finding significant customer support for improving service to worst-served customers, even where this may be relatively expensive to achieve compared to improving average performance for all.

Q43 What are your views on the options presented for WSC? Are there other options that we should consider?

Ofgem should replace the current scheme with an ex-ante funded targeted programme to address poorly served customers, potentially modelled on the approach adopted for SSEH in RIIO-ED1. We expect to be proposing this in our Business Plan submission, in response to feedback from our customer and stakeholder engagement in the North West. This would allow significant work to be completed on those circuits that supply worst-served customers and result in sustainable and enduring improvements.

We are anticipating that such a scheme will be supported by customer willingness-to-pay given the engagement we have already undertaken and that it has the potential to be crafted into a Price Control Deliverable (PCD) which will ensure delivery against its stated aims.

Our stakeholder engagement as part of this consultation response indicated a preference for "option 3" as it "recognises locality based differences which is more realistic and enables DNOs to focus on topical important issues. Certainty is a stronger platform for business planning." Another stated that "everyone, regardless of location or social status, etc, should receive the same level of service…so discrepancies should be understood and addressed."

6 Maintain a safe and resilient network

Q44 Do you have any views on our proposed NARM framework?

We are supportive of the NARM framework and its development from the current equivalent in RIIO-ED1, NASD. We consider that the ED experience in developing and implementing a monetised risk-based approach for RIIO-ED1 places it significantly in advance of the other sectors regulated by Ofgem and hence the NARMs arrangements put in place to remedy the shortcomings in those sectors' approaches should not be assumed to be precedent-setting for RIIO-ED2.

We agree that the introduction of a long-life risk metric is a sensible development which helps ensure the delivery of efficient and effective asset interventions to manage the overall long-term risk of the network. This long-term life risk management is key to ensuring the overall sustainability of the network allowing it to respond to the challenges of the future including the transition to Net Zero.

We have worked with the other DNOs to develop a robust and workable approach to long-life risk which uses the current Common Network Asset Indices Methodology (CNAIM) v1.1 as its basis. We are pleased to see that Ofgem has endorsed the principles behind the proposed approach and commit to working further with Ofgem and the other DNOs to refine the details of this prior to its implementation.

We also agree that commonality can only be achieved with a consistent scope of NARMs and support the proposal that all DNOs report the same asset types within the framework. Where this will result in DNOs applying the asset risk approach to new asset types, there may well be associated data collection arrangements that need to be implemented, the detail of which could be within scope for a future Information Gathering Plan (IGP) requirement. We highlight that the collection of new or additional data to support the implementation of the NARMs approach may well lead to additional costs which will need to be considered in the benchmarking of inspection costs for RIIO-ED2.

We agree with the proposal to use asset register categories and to scrap the previous aggregated 'Health Index category' as this gives greater granularity of risk assessment, as well as avoiding some of the unintended consequences of aggregation seen in NASDs.

It is clear from recent work that there remain some areas with scope for interpretation within the current CNAIM approach and we are working with the other DNOs to provide the additional clarity and guidance on this, particularly in respect of the scoring of 'Observed Condition' factors. This is feeding into the revisions to the CNAIM v1.1 approach to produce CNAIM v2 which we have shared with Ofgem and are confident will give an enhanced basis for measuring and monitoring network risk into RIIO-ED2.

In terms of expansion to other assets, we believe that the current definition of assets within CNAIM is appropriate both in terms of the types of equipment where the costs of proactive management (inspections, maintenance etc.) are justified and in the quantum of the risk being managed. For those assets where this is not the case, and which are typically managed on a fix-on-fail approach, the appropriateness of future volume forecasts can be assessed with reference to several parameters including trend volumes, comparisons with other DNOs etc. We agree that fault rates can be an indicator, but they are high level, trailing and influenced by other factors as noted in the consultation.

In terms of the options presented, we support exploring Option 2 to look at how the principles of risk assessment can be applied to these asset types without collecting the granular asset-specific data required for CNAIM. We believe there are open source data and emerging analytic techniques that will enable us to explore this area for RIIO-ED2, however this is unlikely to be directly comparable with CNAIM itself in the short-term. This is also an area where EJPs may be a useful source of evidence to explore the engineering rationale behind proposed volumes.

Regarding the incentive properties of NARM, we acknowledge the principles set out in the RIIO-2 decision that effectively turn what was an incentive mechanism in RIIO-ED1 to a Price Control Deliverable (PCD) in RIIO-ED2. As such, we note that the removal of any incentive upside from NARM reduces the overall incentive package available for RIIO-ED2 and reduces the likely pace of asset management improvement, adversely impacting customers.

For RIIO-ED2, we expect that the principles of risk trading will be preserved to incentivise risk reduction at lower cost and hence the return of benefits to customers through the TIM mechanism. To that end, we were pleased to receive reassurances through the SRRWG meetings that Ofgem is considering the current RIIO-ED1 NASD arrangements as the basis for the NARM framework in RIIO-ED2, to be supported by the development of CNAIM v2.0 which includes the measurement of long-term risk. We would be most concerned if a version of the NARM Funding Adjustment and Penalty Mechanism currently being discussed for implementation in the Gas Distribution and Transmission reviews was transported across to ED as this appears to represent a move to detailed ex-post regulation.

In terms of justifying investment proposals, we have consistently supported maintaining the link between Cost Benefit Analysis (CBAs) and the measurement of asset risk through CNAIM and a move to a lifetime risk measure further cements these links. As such, we believe that much of the justification for future volumes and the consequent risk outputs can be made relatively mechanistically but acknowledge that there will be a role for EJPs to provide the additional justification where this isn't necessarily the case and/or where future volumes are not supported by recent historic trends. Consequently, a portfolio approach to cost assessment would be appropriate whilst ensuring minimal duplication between the different sources of evidence required.

Q45 Do you agree with our proposal not to introduce outputs or incentives related to workforce resilience?

We do agree with the proposal.

We believe, as we are doing, that DNOs should continue to work with their CEGs, key stakeholders and industry bodies such as the ENA, Prospect and Energy and Utility Skills, to agree a common set of measures and a consistent approach to providing visible and transparent workforce resilience data/metrics. We also agree that the resourcing strategies and metrics should include workforce satisfaction, wellbeing, and diversity and inclusion, but that these should not overly constrain DNOs or drive perverse behaviour because of their design. DNOs require flexibility in developing their own resourcing strategies to meet the needs of the rapidly changing operating environment. The workforce roles will need to evolve to facilitate Net Zero, enable digitalisation of the sector, and to transition to a DSO operating model. The impact of COVID-19 will also need to be considered as the environment has changed significantly in recent months.

Q46 Do you agree with our proposal that DNOs should submit a Cyber Resilience IT Plan and a Cyber Resilience OT plan?

We agree that Network Companies should submit plans for IT and OT, but they should use a standard format and the same framework. We expect to use the Cyber Assessment Framework for this but the industry baseline for OT will be higher. The plans will describe the improvement to be made against these baselines.

We recognise the convergence of OT and IT technology and services that will bring some uncertainty to, and impact on, the Cyber Resilience IT Plan. We expect that in some areas the level of cyber resilience will increase compared to what would normally be the case. There needs to be greater focus at the SRRWG on cyber resilience and perhaps this subject, given its importance and the fact it is a specialist area, needs its own forum. This would elaborate on the threats, requirements, concerns and proposals in this area.

Q47 Are there further requirements of expectations that we should be considering for the DNOs?

The scope of ISO27001 registration across IT and OT should be considered as standard and it is of value, however, this is not an insignificant cost.

The approach to re-openers for cyber is also a consideration given the uncertain nature of cyber threat and the everchanging landscape. We would propose a re-opener at the start of the RIIO-ED2 period and one in the middle given these uncertainties, in line with the proposals for GD/T.

Q48 Do you agree with our proposal for the establishment of a 'climate resilience' taskforce or working group, to help DNOs develop strategies for managing the risks of climate change?

We agree that a 'climate resilience' working group should be established through, and be chaired by, the ENA.

The existing ENA Climate Change Adaptation Reporting Group (CCARG) has been established for the sole purpose of preparing the industry wide Climate Change Adaptation Report which is then used as an appendix to individual companies' submissions to Defra. As such it is convened roughly every five years for a two to three-year period. It does not seek to develop industry wide strategies.

A Climate Resilience working group would build on the good work of the CCARG in identifying and prioritising the risks due to climate change as well as developing ongoing strategies to manage resilience in the medium and longer-terms.

Q49 How should DNO strategies inform best practice that is used across the industry? How can these be used to help DNOs develop longer term investment proposals to manage the risks of climate change?

Analysis for the first two rounds of Climate Change Adaptation Reporting have identified that the biggest risks to electricity networks are:

- Increased frequency and severity of flooding
- Reduction in equipment rating due to higher temperatures
- Increased frequency of storms
- Accelerated vegetation growth due to a warmer wetter climate

DNOs need to develop strategies which will take account of these, and other issues, to ensure the long-term health of the network.

As noted elsewhere in the consultation, through the ENA, DNOs have developed Engineering Technical Reports (ETR) for flood resilience and tree cutting that are applied nationally and form the basis of investment plans. We would expect that the suite of ETRs, or equivalent Engineering Recommendations (ERECs), would expand to cover other risks due to climate change and that they would contribute to the design of future investment proposals.

Q50 Do you agree with our proposal to retain the RIIO-ED1 approach to flood resilience?

We agree that the RIIO-ED1 approach to removing risk on the network should be retained in principle but would like to point out that the 'risk-based' approach used in RIIO-ED1 (which used customer numbers as a weighting) is not appropriate due to the deterministic nature of the requirement. There is no customer weighting factor in ETR138, just a simple threshold at the EHV level of 10,000 customers to reflect the National Flood Resilience Review recommendations.

We also highlight that ETR138 and the RIIO-ED1 approach focus exclusively on EHV and 132kV substation sites. More recent experience of flooding events has led us to undertake selective defence works at vulnerable HV locations which also need to be considered in the price control evaluation process.

In terms of cost assessment, we believe that company plans should be scrutinised for efficiency and to ensure that measures to reduce consequence, as well as probability, have been appropriately evaluated. We see this as an area of work where Engineering Justification Papers (EJPs) will play a supporting role in terms of identifying efficient solutions.

Q51 What are your views on how we/industry reports on progress against flood resilience plans?

We support the continuation of the RIIO-ED1 process with annual reporting through the RIGs. This would appear to align well with the Price Control Deliverable (PCD) definition. As we state in Q2 we would welcome further guidance on the PCD mechanism, particularly the expected materiality threshold that will be applied.

Of note is a previous requirement to provide additional six-monthly reporting to BEIS. This is currently dormant but could be revived if required.

Q52 Do you agree with our proposal to retain the RIIO-ED1 approach to ensuring networks are resilient to trees?

We agree that the existing measures should continue, however, extra measures may need to be considered to cope with the challenge of other emerging issues such as Ash Die Back disease. This is a potential additional area of vegetation management work in RIIO-ED2.

DNOs are already exposed to the impact of tree-related events through the IIS mechanism and therefore already incentivised to ensure appropriate maintenance cutting levels. We suggest that the ETR132 cutting activity could be considered as a Price Control Deliverable (PCD) in RIIO-ED2 as it is less directly linked to a current incentive. As with Q51 we would like further guidance on the PCD mechanism, particularly materiality thresholds.

Q53 Do you agree with our proposal to develop a wider resilience measure over the course of RIIO-ED2? If so, what should it cover?

We are interested to see the type of proposals that are brought forward to measure resilience. In recent years we have been involved in several discussions on developing resilience measures, but we have not seen anything that captures both the wide range of threats to resilience and the diverse nature of our network.

Previous attempts have looked at the levels of preparedness from the fundamental network design standards through to forecasting and response capability. Resilience is provided by this tiered approach to defence against external threats, but it is challenging to combine assessments of the different layers into a single metric due to the very different nature of each part.

The biggest resilience ‘failure’ in our area in recent years was the major interruption to the city of Lancaster during Storm Desmond in December 2015. Although more than 50,000 customers were off supply for nearly two days, 97% of our customers were totally unaffected by the incident. It is difficult to visualise a meaningful and useful measure of resilience which would pick out such localised threats to our network from the wide range of potential impacts.

In developing a metric, it would need to be understood how the measure would be used to identify new investment and work practices, as well as to assess and quantify what benefit that would bring to customers.

In terms of work in RIIO-ED2, we suggest that it would be appropriate for the initial focus to be on identifying areas of co-dependent resilience with other infrastructure as identified in the National Infrastructure Commission report referenced in the consultation.

As well as the resilience activities that have been discussed, we are aware that there are potential technical and infrastructure solutions which will improve the resilience of our networks to storms and other threats. For example, we are investigating the potential to roll out the 'Sentinel' solution[6] which was developed through the NIA. Currently there is no place in the Business Plan Data Template (BPDT) to capture this type of project for evaluation in the price controls.

We would like a 'Resilience' table to be added to the BPDT to capture this type of cost. We propose that it would have a similar format to the 'Legal and Safety' table allowing DNOs to define their own categories of work.

Q54 Do you agree with our proposed approach of retaining the existing arrangements for Black Start, physical security, and telecommunications resilience?

We broadly agree with the proposed approach.

We support the introduction of a re-opener for Black Start, as it is currently unlikely that there will be sufficient clarity on future requirements to enable these to be included within the RIIO-ED2 submissions. This re-opener will need to be designed to accommodate a wide range of potential costs as our current assessment is that the costs of meeting any enhanced standard are likely to be related to additional indirect costs (such as Control Room functions) as well as direct network investment.

As Physical Security requirements are identified independently from the DNO, we believe it is appropriate to retain the current arrangements in this regard.

We note that Ofgem is not currently proposing a re-opener for Telecoms Resilience but an update as part of Draft Determinations in 2022. It would be helpful if Ofgem could specify in more detail what it is expecting to receive as part of the DNO submissions in 2021 as that will help to provide the required clarity in this regard.

Q55 Do you agree with our proposal to include a reopener for physical site security, with a window during the price control and a window at the end of the price control?

We support the retention of a re-opener to cover Critical National Infrastructure (CNI) to adjust revenues following government mandated changes to network site security requirements. This is exactly what re-openers and uncertainty mechanisms should be used for; to cover changes in requirements that are externally driven and outside of companies' control. To that end we propose that no materiality threshold should apply to this re-opener as per the current position for RIIO-ED1. Applying any materiality threshold to a mandated and/or legislative requirement wholly outside of companies' control places all the risk on companies and is inconsistent with the lower risk aspiration as set out by Ofgem for RIIO-2.

It is unclear why this re-opener should be limited to two periods only. Due to the nature of the activity it would be prudent that this re-opener could be applied for at any point in the price control in line with the defined annual window should the need arise.

[6] https://www.enwl.co.uk/zero-carbon/innovation/smaller-projects/network-innovation-allowance/enwl006---sentinel/

Q56 Do you agree with our proposal to continue monitoring the development of telecommunications resilience and reviewing the arrangements as necessary?

We agree with the proposed approach for telecommunications activities and resilience. The recent changes in the definitions in the RIGs supports this treatment.

7 Delivering an environmentally sustainable network

Q57 Do you think our proposed environmental framework will drive DNOs to deliver an environmentally sustainable network?

We are supportive of the proposed environmental framework based on the outline expectations provided in the consultation.

Q58 Do you consider that the proposed areas in scope of the Environmental Action Plan, and associated baseline standards, are appropriate? We particularly welcome views on any areas that should be omitted/included and if new areas should be included, what the baseline standard should be?

We broadly agree with the proposed scope provided and agree that common methodologies should be used by the DNOs to ensure consistency and meaningful assessments.

Notes regarding specific actions areas are detailed below:

Business Carbon Footprint (BCF) – We agree with the need to only include scope 1 and 2 emissions with the science-based target and to limit scope 3 emission reduction progress to the reporting element. Given the complexity and challenges of scope 3 emissions, we believe that clear boundaries should be set out clarifying what to include as this isn’t currently detailed within the consultation. We are supportive of the desire to agree a common BCF methodology. We also believe that when setting the baseline, progress towards reducing BCF in RIIO-ED1 should be taken into account as some DNOs will have already made significant progress in this area.

Sulphur Hexafluoride (SF6) – We agree with Ofgem’s position, although we note that there are potential legislative changes that are yet to be finalised and which may impact on the expectations and deliverables. No firm decisions should be made with regards to the treatment of SF6 in RIIO-ED2 until these changes are known.

Losses – We agree with Ofgem’s position which reflects the views of the ENA Losses Working Group. The RIIO-ED1 reputational incentive (Losses Discretionary Reward (LDR)) combined with our CBA-based investment programme on losses has delivered significant losses savings during the period either through proactive intervention (i.e. programme of replacement of high loss transformers) or through opportunistic investment (i.e. over-sizing cable when installing new cable). We support the continuation of the RIIO-ED1 approach on losses (without the LDR element) but recommend the enhancement of the CBA tool currently being discussed through the Ofgem Cost Assessment Working Group to ensure best value for customers.

Embodied carbon – We agree with the need to consider embodied carbon. Further guidance is needed around what defines a new project in the context of embodied carbon so that clear boundaries are defined. Only once this is determined would we support the need to introduce targets to reduce embodied carbon on specified new projects during RIIO-ED2. We would support an objective to establish a baseline within RIIO-ED2 and look to identify activities to reduce the embodied carbon.

Supply chain – We are broadly supportive of the need for the supply chain to meet high standards of environmental management. More information is required confirming what the qualifying criteria would look like, such as certification to a relevant international standard or other recognised certification. If a requirement is made to audit the supply chain, this could add additional costs which may not be in customers' best interests.

Resource use and waste – We believe that embedding circular economy principles within procurement processes and reporting on the fate of waste materials as a percentage is appropriate.

Whilst we are supportive of the aim for the circular economy, we are opposed to setting a zero waste to landfill target due to the range of materials that are not readily recyclable or recoverable, such as asbestos. A zero waste to landfill target should only be set if it contains specific exclusions.

Biodiversity/natural capital – We are supportive of the need to increase environmental value where possible in our work. However, the increase in 'natural capital' is harder for DNOs as opposed to transmission or other sectors (such as water) as we do not own (comparatively) much physical land. Accordingly, the proposed net gain changes need to be as simple as possible so as not to be too onerous and have a chance of being observable, particularly as DNOs are dependent on land-owners being cooperative to allow monitoring. This could, therefore, be restricted to new infrastructure projects situated on DNO-owned land.

Fluid-filled cables – We are in agreement and would like to highlight the interaction between this element of the EAP and the asset management plans for each company.

Noise pollution – We are in agreement.

NOx and air quality – We do not support this objective as we feel that NOx and air quality is, in effect, accounted for in the BCF by way of fuel emissions. We feel this should be a DNO-led exercise where they operate in areas under a clean air zone or similar, and not be included within an EAP.

Q59 Do you agree that the annual reporting through the Environmental Impact Report will increase transparency of the DNOs' activities and the resulting impacts on the environment?

We have assumed that the Environmental Impact Report is what is referred to within the consultation as the Annual Environment Report (AER). We agree that the reporting would increase transparency but believe that recognition of environmental initiatives and progress from RIIO-ED1 should be taken into account. We also require clarification that this would be an enhancement or replacement of the Environmental Report obligations in RIIO-ED1 to avoid duplication.

Q60 Do you agree with our proposal to introduce a re-opener to accommodate environmental legislative change within the RIIO-ED2 period?

We agree with the proposal to introduce a re-opener in this area on the basis that it can be sufficiently defined to deal with a specific set of circumstances. Based upon our experiences in RIIO-ED1 we expect that changes which will materially affect the activities within the scope of the EAP fall into one of three categories:

- Introduction of new legislation e.g. the potential SF6 change to F-Gas regulations
- Change of enforcement practice or legislative clarification e.g. PCB clarification of expectations from network operators
- Change to /new standards which are imposed by external bodies e.g. Environment Agency/Health Safety Executive e.g. the requirement to inspect cut-outs following smart meter rollout

Q61 Do you agree with our proposed removal of the Losses Discretionary Reward?

We agree with the removal of the Losses Discretionary Reward, and instead support the focus of losses being included as part of the more holistic treatment of environmental impact within companies' overall strategies. We were one of the few DNOs to propose specific losses reduction expenditure in RIIO-ED1 supported by a CBA. Our investment to date will deliver a losses reduction over the RIIO-ED1 period and this will increase with anticipated further investment in the remainder of the period. We propose that this same approach should continue for RIIO-ED2 where specific company actions/investment can result in a positive benefit for customers to be funded ex-ante within totex allowances.

Q62 Do you agree with our proposal to retain the visual impact allowance for RIIO- ED2?

We agree, and as stated in the consultation, that visual impact allowances provide a flexible means for DNOs to undertake works identified and prioritised by relevant stakeholders which can make a significant difference to the visual environment of impacted areas. They also have the potential to deliver incidental benefits such as increased storm resilience and we have experience of such projects being used to leverage additional funding for wider landscape improvement schemes maximising the overall benefit to customers in our area.

Q63 Do you agree with our proposed approach to setting a funding pot for the visual impact allowance for RIIO-ED2?

In principle we agree, although we note that the visual amenity values used in Transmission are significantly higher, indicating an enhanced national customer willingness-to-pay based on more contemporary assessments. Investment in visual improvements by the DNO sector allows the benefits to be shared around the country – at present Transmission benefits are highly localised to a small number of expensive schemes and we note that there is no benefit from the Transmission scheme in the North West despite North West customers contributing to it through their bills. In contrast, we intend to fully utilise our entitlement in RIIO-ED1 and plan to continue to do so in RIIO-ED2.

Further one of our stakeholders stated that "It is fair to calculate the allowance for each DNO as an average of the number of customers and length of lines to be undergrounded in each region. With the geographical extension to both the Lake District and Yorkshire Dales National Parks back in 2016, the length of lines that Electricity North West is responsible for has increased, so its portion of the overall undergrounding allowance in RIIO-ED2 should also increase."

Sector Specific Methodology Consultation response

Annex 3: Keeping Bills Low

September 2020

Contents

1 Approach to Aggregated Econometric Analysis

Q1 Do you agree with our proposal to include totex benchmarking in our toolbox for cost assessment in RIIO-ED2?

We support the use of totex benchmarking as part of the cost assessment toolkit for RIIO-ED2, but Ofgem needs to be careful not to put undue weight on it as it tends to incentivise lowest cost and disregard quality of outcomes for customers.

We were concerned to observe the overreliance on a single totex model as observed in the Draft Determination (DDs)for RIIO-GD2. The use of a single top-down totex regression model to establish the majority of the cost baseline (c.84%) for the industry is out of step with regulatory best practice in PR19 and that utilised in RIIO-ED1.

It is generally accepted that there is no single perfect econometric model. Ofwat concluded as part of the PR19 framework that "*All models are subject to error and a degree of bias. In many instances, it is not possible to identify a single "preferred" econometric model that clearly prevails over all others. To mitigate risks of error and bias we [Ofwat] do not rely on a single model. Rather, we [Ofwat] use a diverse set of models, with different drivers and different levels of aggregation, in triangulation*."[1]

This mirrors the RIIO-ED1 approach where totex models were collectively limited to a 50 percent weighting in the overall slow-track assessment. We are not necessarily suggesting a 50 percent weighting to a totex model at this stage, but that work is done to establish a robust modelling approach.

We suggest a more holistic approach for RIIO-ED2 that uses both top-down and bottom up regression models, including the consideration of middle models, as well as non-regression or disaggregated modelling where appropriate.

Totex models can be complemented through the targeted used of disaggregated modelling techniques, such as including unit cost modelling where there are distinct costs and activities where cost trade-offs don't exist, and where justified differences between companies occur which can't be explained or appropriately accounted for through cost drivers in econometric totex regression models. In essence, multiple models, and modelling methods, which are aggregated or triangulated should be considered to account for the inevitable and unavoidable imperfect assessment process and individual model imperfections.

Q2 What cost drivers do you consider appropriate for our proposed totex benchmarking? Why?

In terms of the application of totex benchmarking, we consider that Modern Equivalent Asset Value (MEAV) continues to be the most appropriate approach as used in RIIO-ED1. Most of our current costs are a function of the current asset base and need to be assessed in that context. Despite extensive discussion in the Ofgem RIIO-ED2 Cost Assessment Working Group (CAWG), no viable alternative has currently been demonstrated.

We do suggest that the benchmarking of future costs needs to consider future drivers, particularly in specific areas. This will have particular relevance in the area of future demand management and DSO

[1] Supplementary technical appendix: Econometric approach, pg.5, Ofwat, January 2019

functions, where there may be limited impact on MEAV through non-asset solutions but still with associated efficient costs incurred.

Due to the inability of totex approaches to appropriately consider the quality of outcomes, we believe it needs to be supplemented with other forms of econometric analysis including disaggregated modelling as set out in our answer to Q1.

Q3 What are your views on the use of both historical and forecast data in our modelling?

We consider that the ED sector is relatively well placed in this regard, and more so than at RIIO-ED1, due to the stability of the RIGs over an extended period of time. However, Ofgem needs to ensure data comparability, particularly if reaching back into DPCR5 where confidence in the comparability of data reduces.

There are elements of the cost base where history is a guide to future requirements and historical data as the basis for this trend analysis can be a useful component of the assessment toolkit. We would highlight however that there are other significant areas where history is a very poor indicator of future costs especially in a changing operating environment, e.g. Net Zero, decarbonisation and flexibility, or where other legislative changes or regional differences may be driving a divergence in costs from those observed historically. In these areas, spend patterns in 2010 have little to no relevance to the challenges of 2028.

Our particular concern is on the potential application of any 'lesser of' approaches in areas where history is a poor guide. Ofgem should exercise extreme caution in this area.

Q4 At what level should we set the efficiency benchmark?

We consider that the benchmark should be set at the Upper Quartile (UQ), in line with previous practice.

We note that the RIIO-GD2 Draft Determination has used the 85th percentile but we do not support this. This is a reaction to the overall levels of underspend observed in that sector over RIIO-GD1, however, the use of a more stringent benchmark suggests a level of modelling accuracy that is unlikely to be supported by a single top-down totex regression model that covers the majority of the cost baseline as used in RIIO-GD2.

Therefore, Ofgem should think carefully about using such analysis to support the use of a more stringent benchmark, especially given the context in ED. Delivery of efficiencies in the period of RIIO-1 will be due to a mixture of reasons and not necessarily, and certainly not in RIIO-ED1, be because the benchmark used wasn't stringent enough. Interlinkages with other regulatory mechanisms such as the lowering of the totex incentive mechanism (TIM) will also change the dynamics and incentives for companies in RIIO-2.

Of further note is that in the CMA's redetermination of PR14 with regard to the Bristol Water review where it used an average benchmark as it considered that the use of an UQ benchmark may overstate inefficiency. This is particularly important where modelling is solely reliant on single methods and models and where the techniques used can't distinguish between modelling 'noise' and genuine inefficiency.

As the RIIO-ED2 price control is not commencing until 2023, Ofgem should take the opportunity to fully digest the insights from the CMA made for PR19 redeterminations and consider their application in the cost assessment process for RIIO-ED2. The use of more stringent than UQ efficiency benchmarks are being reviewed as part of these appeals. It is therefore important that the framework and future policy positions taken as part of RIIO-ED2 are made mindful of the CMA insights, but independently of other sectors and considering the evidence and unique circumstances for RIIO-ED2 at the individual licensee level. The decarbonisation challenges as well as the transformative changes required are not inherently part of the water sector as they are in energy.

Q5 Do you agree with the proposed criteria for developing cost pools for a middle-up approach?

We agree that the approach set out in the consultation appears a sensible basis for a middle-up approach and that the CEPA criteria appear appropriate.

Q6 What cost drivers would be appropriate in a middle-up approach?

This primarily depends on the categorisation within any middle-up approach as the cost drivers need to be appropriate for each category. We suggest that the equivalent practice in RIIO-ED1 is used as the precedent unless there is clear evidence to change.

Q7 What are your views on the CEPA developed totex and opex plus approach? What opex activities are there trade-offs that support the rationale for testing 'totex and opex plus' modelling?

We support a toolkit approach to cost assessment as there is no one 'correct' way of making such an assessment. If the totex and opex plus approach meets the criteria outlined and provides intuitive results that make economic sense and has strong explanatory reasoning, then we are happy to support such a method as part of the toolkit.

Q8 Do you believe it is appropriate to use bottom-up, activity-level, disaggregated modelling in RIIO-ED2?

We agree the use of bottom-up models is complementary to the totex approach, particularly in areas where a separate output applies (e.g. NARM), or where the DNO is proposing novel, stakeholder-supported investment.

Q9 If we use a combination of aggregated and disaggregated modelling approaches, how should we determine the weight we apply to each, in combining our analysis?

We suggest that Ofgem considers the combination of totex and disaggregated (disagg) modelling in two ways:

1. Assessing the same areas of the cost base and triangulating the results (as per RIIO-ED1); and

2. A hybrid approach where the cost base is split into areas covered by totex and disaggregated models and the results are added. This would allow flexibility for areas of output difference between DNOs to be fairly assessed using a disaggregated approach with reference to supporting Cost Benefit Analysis (CBA) and Engineering Justification Papers (EJP).

It is possible to have a distinction between costs and the methods of how they are assessed i.e. the use of cost pools. In this situation (i.e. 2.), there is no need to consider the method of aggregation between cost items or pools as it would be simply an addition. This approach can be observed in PR19 where base costs and enhancement costs were assessed, broadly speaking, on a totex basis and a disagg basis respectively and then combined to give a totex allowance for the period.

Where multiple models or methods assessing the same cost pool are used in approach 2. these would require combining, or triangulating. As discussed, our preference is that Ofgem does not rely on a single cost model for any item as, such in this scenario, aggregation of multiple models within cost pools will be required. Our preference is that this is done on a straight average weighting depending on the number of models included (i.e. three models would each be given equal weighting of c.33 percent). Any deviation away from equal weighting by Ofgem should be clearly signposted, justified and evidenced as to why this decision has been taken.

Q10 If we did not use disaggregated modelling approaches, what approach should we consider for disaggregating totex allowances for the setting of PCDs?

We propose the use of disaggregated modelling for setting PCDs to ensure clear linkages between the deliverable and the allowed costs to deliver them without relying on inferencing or extrapolating the results of an overarching totex assessment approach.

2 Model specification

Q11 What model estimation options should be considered for our cost assessment and why?

We suggest that further effort should be focused on reviewing the Random Effects (RE) approach as this looks at time variance. The Ordinary Least Squares (OLS) approach allocates all noise to inefficiency which may not be the case and therefore the exploration of more sophisticated model estimations options is worthwhile where the data available supports it, and it has discernible benefit to the assessment process.

Q12 Do you agree with our proposal to continue using Cobb-Douglas functional form? Why?

We agree with this proposal. The Cobb-Douglas functional form is a long-established and proven approach. We have not seen any evidence to suggest that it is not fit-for-purpose.

Q13 Do you have any views on our proposed model selection criteria?

We broadly agree with the model selection criteria as set out but offer some comments on each in turn below.

Economic/technical rationale: We agree that the model specifications and results should have a clear economic/technical rationale. This should also extend to being intuitive and make engineering sense. We agree with the aim to safeguard against 'data mining' and therefore this criterion and its interaction with the criterion on robustness, namely statistical test, is critically important to guard against this poor practice. Similarly cost drivers may make sense from an economic/technical rationale but could suffer from issues of multicollinearity which can be avoided through appropriate statistical testing.

Transparency: We agree that this should include the data used, the results and ease of interpretation for stakeholders. It should also include where data adjustments and or reallocations are made as well as the justification on how/why these changes are having to be made.

Additionally, transparency should not preclude complexity. Models can be transparent and at the same time complex. One should not prevent the other and, as evidenced by PR19, multiple model forms and methods can be combined in a way that is transparent to all stakeholders, if they are well understood and able to be articulated by the regulator, as well as presented in an easily accessible and transparent way. This could be an extremely important criterion for Ofgem to test itself against. This should consider the objectives, and how it has achieved these through the suite of models and tools used as part of its cost assessment process. In the interests of transparency all models should be published early in the process, along with all the information needed to fully understand, interpret and recreate them.

Robustness: We agree with this selection criterion. Models do need to have statistical testing undertaken on them as well as sensitivity analysis on the underlying assumptions. Big changes and large ranges with regards to efficiency scores should give rise to concerns. However, Ofgem should not be blinded by statistical testing. A varied cost assessment toolkit considering a variety of models, methods and techniques that make economic and engineering sense are more important than overfitting models to suffice statistical testing criteria. The over reliance on statistical tests was the failing of Ofwat at PR14 and Ofgem should seek to avoid this regulatory pitfall.

3 Regional and company specific factors

Q14 Do you agree with the proposed criteria for assessing regional and company specific cost factors that we have outlined?

We agree that the broad criteria set out appear appropriate. We encourage that further detail around what evidence is required to suffice the criteria should be set out in the Business Plan Guidance documentation.

Q15 What are your views on our approaches to account for regional and company specific cost factors in our modelling?

Our overall preference is for post-modelling adjustments as this aids transparency in terms of the quantum of the adjustment made and retains the integrity of the associated model. The document does describe the pros and cons to each of the three possible means to adjust for regional and company specific factors, hence the selection of approach needs to be weighed against its individual merits and drawbacks.

4 Real price effects and ongoing efficiency

Q16 Do you agree with our proposed approach to index RPEs, rather than setting an ex-ante allowance based on forecasts?

We understand that the proposal from Ofgem is "the same approach for gas distribution and transmission in our [Ofgems] RIIO-2 draft determinations"[2]. Therefore this would consist of "Index RPEs, including a forecast of RPEs in upfront allowances, then true-up annually based on actual outturn information"[3]. In effect this will include ex-ante allowances for companies that are then trued-up annually.

We support the principle of identifying an index/indices to manage the risk of RPEs, but we would note that extreme care is required in the selection of appropriate indices that closely match the basket of goods purchased by the typical DNO.

We agree with the observation made in the DD consultation[4] that the *proposed cost structures, assessment of materiality, and choice of indices* are crucial to ensuring a fair assessment and allowance for RPEs. As with the process run for GD/T2 any proposal needs to be done on a sector specific basis. This sector specific approach is evidenced by the use of notional company cost structures for GDNs and company specific cost structures for transmission companies.

Ofgem should also consider very carefully the impact of COVID-19 and the effect this will have on the indexation(s) used in the ongoing annual true-up of RPE and allowances. Consideration should be given to whether the index(es) used will reflect accurately the cost pressures faced by the sector if it is couched in the experience of the wider economy. Ofgem indicates its view that the impact of COVID-19 on the energy sector is different to the wider or more general economy, and this should be considered very carefully with respect to RPE allowances and ongoing true-up mechanisms.

We also note that RPE allowances and ongoing efficiency assumptions form part of the referrals of the final determinations in PR19 to the CMA and as such it is important that robust and well evidenced conclusions and allowances are made in respect of these two items. Because of the RIIO-ED2 price control not commencing until 2023, Ofgem has the opportunity to fully digest the findings of the CMA and how these should be considered in relation to RIIO-ED2. It is therefore important that the framework and future policy positions taken as part of RIIO-ED2 are made mindful of the CMA views and findings, but independently of other sectors and considering the evidence and unique circumstances for RIIO-ED2 specifically as well as for each licensee.

[2] RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, paragraph 6.12, Ofgem
[3] RIIO-2 Draft Determinations - Core Document, paragraph 5.15, Ofgem
[4] RIIO-2 Draft Determinations - Core Document, question 10, Ofgem.

Q17 Do you agree with our proposal to have a high materiality threshold for RPEs? What are your views on the materiality level for RPE submissions, and the criteria we use to select input price indices?

There needs to be a read across to the definition of materiality in the design of the uncertainty mechanisms for RIIO-ED2. We therefore suggest that the definition of the materiality threshold in this regard needs to be consistent with similar treatment within the price control framework (adjusted for its annual equivalence) to avoid having multiple interpretations.

Q18 Do you agree with the suggested common input and expenditure categories for structuring RPEs in ED2?

We agree that the proposed input and expenditure categories remain appropriate.

Care will need to be taken to ensure the short-term impacts of the COVID-19 pandemic are appropriately adjusted for (see our answer to Q16 for more detail).

Q19 Do you agree with our proposed approach, and its scope, to set an ongoing efficiency assumption for RIIO-ED2?

Based on the justification for the proposed positions in DDs for GD and Transmission (e.g. ongoing efficiency and catch-up efficiency) we have concerns that Ofgem is confusing, and mis-applying, the various levers in the RIIO toolkit as well as what they are designed to cover.

We do not support the incorporation of 0.2 percent additional efficiency due to previous innovation funding in RIIO-1 as set out in the DDs, nor its application to RIIO-ED2. Innovation investment has been primarily focused on meeting future challenges and the resulting efficiencies are visible in company submissions to Ofgem in terms of the discounts (avoided costs) that are applied to future forecasts compared to the counterfactual of traditional solutions. Innovation funding has not generally been focussed on reducing the costs of ongoing operations and meeting existing requirements. This is because companies are incentivised to self-fund innovation to lower costs and benefit through other levers in the RIIO framework such as the TIM, and customers see the benefit included in our business plan.

Careful consideration of the calibration of ongoing efficiency and what this is aimed at achieving, as well as the consideration of catch-up efficiency, and what that covers, needs to be given. It is important that being innovative doesn't become a zero-sum game to companies who need to balance a range of priorities or Ofgem's novel approach become a disincentive to innovate. The regulatory framework needs to have real rewards for innovation, not unmerited additional discounts to future costs for past success in addressing future long-term challenges facing consumers, stakeholders and companies.

We also have concerns that the most recent data observations are not being included in the assessment for GD/T2. The impact of COVID-19 will be underplayed and underassessed on this basis. A global event with the impact that COVID-19 has had is unprecedented. In operating our ED business, at the time of this response in September 2020, we are still assessing the medium and longer-term implications of COVID-19. Any ongoing productivity assumption needs to be cognisant of this unknown impact and be calibrated in a way that is well informed in its assumption with quantification of all the facts.

It is incorrect to say that our sector is not directly impacted by changes in the wider economy. This extends to where Ofgem is considering setting forward looking ongoing efficiency assumptions solely on the basis of those observed in RIIO-ED1 or earlier[5]. We do not support the use of this experimental method on its own. Traditional methods drawing on wider productivity assessment should be the basis for calibration of ongoing efficiency assumptions.

We also note that Real Price Effects (RPEs) allowances and ongoing efficiency assumptions form part of the referrals of the final determinations in PR19 to the CMA and as such it is important that robust and well evidenced conclusions and allowances are made with respect to these two items.

Q20 Do you agree with our proposal to use a growth accounting approach as our primary source of evidence to set an ongoing efficiency assumption? What parameters would best support this approach?

Use of such a model must be set against a context of declining UK productivity rates since the 2008 financial crisis. The recent COVID-19 impact will also have a significant impact on general UK productivity rates. As such, use of this model must be done with a great deal of caution, noting a critical need for an accurate specification to deliver realistic expected productivity gains based on the circumstances that will prevail. We believe Ofgem should adopt a wider assessment approach that also takes account of Bank of England (BoE) and Office for Budget Responsibility (OBR) forecasts.

We support the comprehensive analysis and conclusions First Economics draw in their paper for the ENA[6] in the recent GD/T Draft Determination submission.

5 Disaggregated Cost assessment

Q21 Do you agree with our proposed approach on forecasting options for RIIO- ED2

We do not agree with the proposed approach[7] that considers a common set with best view. There is no benefit to our customers following this approach due to the fact that this is clearly a centralised forecasting approach. All the disadvantages which are described in our response to questions 4 to 7 on the Overview document apply and should be reviewed in conjunction with our response to this question. Any top down allocation of LCT volumes[8], simplistic trending of annual peak demand growth, and simplistic top down flexibility assumptions[9] cannot capture the regional peak demand growth expected from a decentralised forecasting approach that has bottom up and half-hourly through year modelling in its core and is able to:

- Model regional EV charging based not only on EVs registered in a location, but importantly on the different types of charging expected per region (e.g. off-street domestic as opposed to destination charging based on work and shop commuters, as well as rapid charging based on regional data);

[5] RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, paragraph 6.42, Ofgem
[6] Frontier Productivity Growth (August 2020), First Economics
[7] RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, option 3, figure 5, Ofgem
[8] Electric Vehicles and Heat Pumps
[9] DSR, smart meters, smart EV charging

- Model smart EV charging taking into account the demand profiles of network regions to shift demand at different times on different locations and assess effects at higher voltage levels via half-hourly bottom-up aggregation;

- Model peak demand growth taking into account how all demand components are added including not only regional uptake trends (e.g., higher heat pump uptakes on areas without access to gas networks), but also half-hourly behaviour of each demand component[10];

- Include regional connections activity taking into account confidence factors for regional historical performance analysis and project specific information (e.g. expected year of energisation, requests from customers to DNO, profile characteristics based on type of load etc); and

- Model generation/battery storage uptake trends taking into account regional network planning information that can influence customer decisions (e.g. available capacity for generation per BSP), as well as regional realities such as availability of land / customer building types for the uptake of renewables.

Failure to take into account these effects using a decentralised approach with bottom up and half-hourly through year modelling is expected to reduce our confidence in capturing regional demand and generation growth trends and capturing the associated uncertainties.

The inadequacy and inherent disadvantages of using centralised forecasting approaches for distribution network planning are the main reason that we have previously scored option 3 not only behind option 2 (Open Networks approach with DFES standardisation), but also behind option 1 where a decentralised forecast without any standardisation and common scenario assumptions across DNOs is assumed.

Ofgem should require a single approach for both cost assessment and our Business Plan submission. In a recent RIIO-ED2 Overarching Working Group (OAWG) (4 September 2020) it was suggested that there could be different approaches required by Ofgem for different Ofgem purposes.

Q22 What are your views on our proposal for establishing network impacts and assessing LRE requirements for RIIO-ED2?

We agree with the proposals for establishing network impacts in RIIO-ED2. Our Business Plan submission will include proposals to use smart meter data further supported by the installation of monitoring equipment[11](in some circumstances only for a limited period) to:

- Understand the current utilisation of the network and target interventions only when and where needed to avoid stranded assets and/or exceed network capacity; and,
- Use, in a coordinated manner, smart meter data with monitoring data that needs to be captured by installed equipment (e.g., harmonic distortion levels, voltages at head of

[10] e.g. regional DSR and smart meter effects shifting demand at different times based on primary substation loading per half hour to affect BSPs and GSPs at times defined by the loading profiles at lower voltages and not the GSP or BSP profiles
[11] Where the volume of these are justified based on DFES forecasts

feeders) to improve our ability to target interventions for the benefit of the whole network and the whole range of issues.

This builds on our approach in RIIO-ED1 with the introduction of the connect and manage programme for LCTs. We will provide additional information in our Business Plan submission.

Q23 Do you agree with our proposal to compare flexibility solutions and network based solutions evenly in our cost assessment?

We fully support the proposal to compare flexibility solutions and network based solutions evenly in the cost assessment for RIIO-ED2 as we see that flexibility can potentially provide significant benefits to our customers, but the approach should not presume, or be biased, in favour of flexibility (or other innovative approaches). The assessment basis needs to be carried out in consumers' interests first and foremost.

We would welcome further clarity on the cost assessment process in this regard, including how assumptions on the availability of flexibility will be considered so that companies aren't unfairly penalised for legitimate regional differences in this regard.

We have been instrumental in driving forward a common evaluation methodology for assessing the solution options through the work of the ENA Open Networks project so that the decision-making process, and the results from the evaluation, are open and transparent. The tool is due to be completed this year and implemented by 1 April 2021 and builds on our pioneering work in developing the Real Options Cost Benefit Analysis (ROCBA)[12]. Delivering commonality of evaluation and placing the methodology and evaluation tool under open governance will provide the foundation for its ongoing development. This tool can be used for determining the ceiling price for flexibility and has the potential to be used in any comparison between flexible solutions and network based solutions.

Q24 How should we treat the fixed costs of procuring flexibility when considering flexibility solutions as an alternative to reinforcement?

We suggest that the costs of procuring flexibility should be an identified cost in addition to the costs of the flexibility solution itself. This would be akin to the treatment of the network planning and design costs associated with the delivery of network solutions which are identified separately and treated as a component of Closely Associated Indirect costs (CAIs). This would mean that in the evaluation methodology the options are compared on an equivalent and fair basis.

Q25 What are you views on the use of LIs as outputs in RIIO-ED2?

As discussed within Ofgem working groups, we agree that Load Indices (LIs) are a very partial view of both utilisation and drivers for reinforcement and could usefully be supplemented in time with additional measures that look at factors such as generation constraints. We have not, to date, seen detailed proposals in these areas that are ready to implement, but are happy to contribute to the ongoing debate and will work with Ofgem to define appropriate utilisation and risk metrics. One

[12] https://www.enwl.co.uk/zero-carbon/innovation/smaller-projects/network-innovation-allowance/enwl001---demand-scenarios/real-options-model/

suggestion would be a simple traffic light system for loading, DG hosting capacity and fault level per substation. Currently LIs apply to higher voltage levels only.

More broadly within the overall area of reinforcement, we highlight that whilst network risk associated with demand is covered by the current LI methodology for first circuit outages the current methodology does not cover risk for second circuit outages (N-2) which applies to larger demand groups (>100MW) only.

That said, we agree with the proposed retention of LIs as an overall indicator of utilisation and also support a review of the bandings and current weightings to enable the approach to produce more meaningful utilisation data. This should be done through the SRRWG.

Q26 What are you views on the treatment of incremental costs in RIIO-ED2?

In terms of the options presented in the consultation, we suggest that 'Option 2'[13] is the most appropriate and that it is applied in defined areas where the impact of incremental costs has the potential to distort cost assessment. This is equivalent to the current treatment of losses expenditure within the RIIO-ED1 RIGs where incremental costs are reported alongside the main cost driver and included in a memo table to give a consolidated view of total losses expenditure.

Ofgem would need to ensure that the basis of any disaggregated cost assessment is clear on which is being used to ensure consistency.

Q27 Do you agree with our proposal to maintain the RIIO-ED1 approach to assessing Non-op capex costs in RIIO-ED2?

We broadly agree with this proposal.

Ofgem will need to consider how to appropriately accommodate the impacts of the transition to low carbon on Property, Vehicles and Transport costs within this framework and also potentially allow DNOs to separate out any significant IT system investment to be subject to separate justification and scrutiny.

Q28 Do you agree with our proposal to maintain the RIIO-ED1 approach to assessing NLRE in RIIO-ED2?

We broadly agree with this proposal and support the suggestion to simplify the workbooks associated with the NASD/NARM deliverables. We suggest that Ofgem gives thought to the process by which any adjustments to future volumes arising from the application of the Asset Replacement modelling and/or scrutiny of CBAs/EJPs are reflected into the NARM targets otherwise there will be a mismatch between the risk targets and the volumes allowed to achieve them. A re-statement process would seem to be required to support this and aid transparency.

[13] *Option 2 – Report total costs against the primary investment driver, with a supporting memo table(s) setting out incremental costs*

Q29 Do you agree with our proposal to maintain the RIIO-ED1 approach to assessing NOCs in RIIO-ED2?

We agree that the RIIO-ED1 approach remains broadly appropriate but highlight that these costs are likely to grow with maintenance requirements for new smart devices and monitoring equipment.

There will potentially be, subject to additional Ofgem requirements on inspection, data gathering as part of the NARM framework which will need to be considered as well as the costs associated with delivering this requirement.

We also repeat the point made in RIIO-ED1 that inspection and maintenance costs are often the most effective means of ensuring longevity of assets and that intelligent decisions are made in terms of investment prioritisation to maximise the effectiveness of interventions. We would be concerned if the approach adopted by Ofgem presumed a race to the bottom in these cost categories as they are often facilitators of cost reductions in other parts of the cost base.

Q30 Do you agree with our proposal to maintain the RIIO-ED1 approach for assessing CAIs in RIIO-ED2?

We agree that maintaining the RIIO-ED1 approach is broadly appropriate.

The CAI category is an amalgam of functions driven by the size of the existing asset base (control centre, call centre etc.) and those strongly linked to the quantum of work being delivered (network design, project management etc.). It is also affected by company decisions on outsourcing of functions, particularly with regard to construction services.

As such, any specific CAI modelling results should not be treated in isolation but considered in the context of the activities with which they are closely associated to give a rounded view of efficiency.

Q31 What are your views on the different approaches presented for the treatment of BSCs in RIIO-ED2?

We support a consistent approach to that used in RIIO-ED1 in pooling of suitable BSC sub-categories, and inclusion within an econometric model using MEAV as the cost driver seems appropriate.

We strongly believe that any analysis should account for fixed costs. We also suggest that the nature of IT expenditure within, and between, companies warrants separate assessment to the other BSC sub-categories.

6 Cost benefit Analysis

Q32 Do you agree with our proposed application of CBA in the appraisal of investment options for RIIO-ED2?

We agree that CBAs will be an important component of the needs case of the submission in those areas where benefits can be clearly monetised against an agreed framework. We also agree that their requirement should be proportionate to the expenditure areas that they support.

There is significant detail in the consultation document that we suggest is formed into a specific set of guidance on the application of CBA models which can then be read alongside the separate BPDT Guidance document. This will need to accompany an updated CBA template which we have led discussions on with Ofgem. We understand other DNOs are happy to continue assisting the completion of this work.

As Ofgem is aware, we have been proposing a number of enhancements to the current CBA approach and are disappointed that the opportunity hasn't been taken to consult on these. We will continue to work on the three broad areas of:

1. Expanding the representative basket of benefits;
2. Variation on fixed factors (such as VoLL and Carbon); and
3. Use of probabilistic assessment techniques.

Our stakeholder engagement as part of this consultation response has also indicated that expanding the representative basket of benefits is important. One stated "it is imperative that the return on investment in any project is able to demonstrate customer, stakeholder and wider community benefits effectively and transparently." Additionally, this is of increasing importance when considering innovate solutions such as Smart Street and energy efficiency measures more widely. One stakeholder stated that they "endorse the wide scale deployment of programmes such as Smart Street which, in addition to preparing the network for the future, will save customers money, without relying on behavioural changes or the need for households and businesses to accommodate new technologies."

We will continue to support this and work with DNOs and other stakeholders to develop the CBA process and model for RIIO-ED2. We consider the CBA, associated guidance and developments to the approach a key priority for timely progression through the Ofgem working group programme for RIIO-ED2. An enhanced CBA approach will improve the quality of decisions made and therefore drive additional consumer benefits.

7 Engineering Justification papers

Q33 Do agree with our proposals to retain the requirement for DNOs to produce Engineering Justification Papers?

We believe that EJPs can form a useful component of the overall evidence base for the submission, however, care is required to ensure these are complementary to other forms of evidence and not a duplication.

We would also welcome clarity on how the results of EJP review are intended to feed into the cost assessment process in terms of modelling adjustments. The consultation discusses the decision-making process and supporting data and we are interested to understand how this fits with the cost assessment framework as the same costs can be arrived at via very different approaches.

Q34 Do you agree with our proposal retain the assessment framework for EJPs developed as part of the RIIO2 process?

We broadly agree with this proposal set out in this consultation but there is a need for it to be modified to work optimally in a RIIO-ED2 context.

Some of the elements of the DNO submissions will have timing and locational elements of uncertainty within them, and we are concerned that an approach borne in the assessment of high-value, long-duration Transmission projects cannot be transported easily across to RIIO-ED2. Many of the aspects noted in this section imply a level of advance detail planning (e.g. market-based tenders) which are simply inappropriate for a DNO context.

Q35 Do agree with our proposal to adopt the principals outlined above to guide the production of EJPS and focus the engineering submission?

As noted in other responses, we are supportive of EJPs where they are a valuable and distinct addition to the evidence base of the submission and consequently support the first three principles listed in the consultation document.

We are however unclear on the role of the fourth principle in assessing the decision-making process itself. As raised with Ofgem in working groups, it is unclear how Ofgem proposes to triage views of the decision-making process and the resulting decision making outcome in its cost assessment, and therefore it is unclear how significant an input detail in the process it should be.

8 Data assurance and compliance

Q36 What specific activities and methods should be adopted to ensure the Data, Data Assurance and Compliance processes of the RIIO-ED2 price control are run as effectively as possible?

We welcome the proposed steps to modernise data assurance, compliance and exchange between Ofgem and network companies including a single consolidated licence condition to specify assurance across the framework.

We note progress to date in this area through RIIO-ED1, providing a useful and effective baseline to build on in RIIO-ED2 and producing tried and tested processes, such as the DAG framework. Network companies have been collaborating effectively through the Open Networks and RIIO-ED2 working groups, which are now well established and proven vehicles for achieving standardisation.

We support the development of Ofgem's proposed improvements but recommend that these are defined as early as possible to facilitate consistency across network companies, in a timely manner. The focus of effort should be on data quality and consistency initially rather than on technology to exchange data – spreadsheets work satisfactorily for annual data returns. Whilst we support improvements to data exchange, specific solutions such as Application Programming Interface solutions (APIs), that are typically used for daily data exchange, should be carefully considered to identify their benefit case in more detail to ensure they are appropriate for what are usually annual reporting requirements.

As data is a key enabler of the road to Net Zero and transition to Distribution System Operation (DSO), we agree that data accuracy must attract more attention and importance in the regulatory framework in RIIO-ED2. We expect the scale and frequency of data exchanges between network companies and Ofgem to increase over RIIO-ED2, and therefore suggest Ofgem implements the recommendations from the EDTF; assess and triage relevant, meaningful and valuable data points for stakeholders and prioritise these to streamline and accelerate their assessment processes. Such activities will facilitate closer working, more efficient and faster data exchange between companies and Ofgem, thereby enabling Ofgem's more active role in decision making in RIIO-ED2. Network companies have demonstrated agility in meeting tight timescales; for example, provision of Digitalisation strategies within three months of Ofgem's request. A similarly agile assessment and feedback loop will become critical in RIIO-ED2.

Increased transparency should be provided on how reported data will be used, to support the greater understanding of reporting criteria and consistency across network companies. Regulatory reporting is a costly exercise that needs to be considered in the context of the value delivered for consumers. Ofgem should challenge itself to identify the reporting requirements that will be used to improve outcomes for customers.

This should also apply to the Business Plan assessment process in a timely manner in order for DNOs to reflect this in their Business Plan submissions. The models Ofgem will use to assess Business Plans should be shared in advance, giving network companies appropriate time to conduct their own assessments, such as on financeability, using these models. Further clarity should also be provided on the overall assessment process, including timescales for RIIO-2 Challenge group review and supplementary questions, and specific details of the assessment, such as anticipated modelling techniques.

We note the importance of visibility and transparency on requirements as well as guidance from Ofgem to support data assurance activities. Provision of clear requirements in a timely manner are critical in enabling network companies to implement robust assurance plans, reducing risk of incomplete, unclear or mis-reporting as well as inaccuracies and ensuring delivery of assured data on time. RIIO-ED1 has demonstrated the importance of high quality commentaries to accompany reported data, and this should continue as a requirement into RIIO-ED2.

Assurance must be appropriate and proportionate to the level of risk and importance attributed to the data provided. We therefore recommend Ofgem provides clear guidance on expectations on assurance for reported data in a timely manner or, alternatively, make clear that the level of assurance is for companies to decide. Should Ofgem want to specify assurance activities, especially external assurance if required on several areas of the Business Plan, then this should be communicated as early as possible to allow reasonable time to plan appropriately ahead of the submission deadlines. Careful consideration should be given to how the level of prescription in DAG compared with the intimated level of flexibility within the consultation can be applied together under the same assurance framework.

We agree with Ofgem's principle of placing greater focus and importance on data assurance. We welcome Ofgem applying the same principles and using internal peer review and assurance via the Government Actuary's Department, which was undertaken on the Gas, Transmission and ESO Draft

Determination models[14] and previously within ED, as demonstrated in the Specified Street Works Costs reopener assessment[15]. We recommend the same approach is provided for significant publications relating to the RIIO-ED2 framework.

9 Uncertainty mechanisms

Q37 Do you agree with our proposed uncertainty mechanisms and their design?

We support a limited number of targeted uncertainty mechanisms that are well defined and are clear as to what risk or uncertainty they are to address in the RIIO-ED2 period. We do not support macro or broad measures such as the mid-period review reopener deployed in RIIO-ED1 as the broadness of the mechanism leads to a lack of clarity for companies and Ofgem about how and why these should be applied and assessed.

Based on Table 7 in the consultation document, we provide comments on the individual mechanisms and their proposed design below:

[14] GAD Audit Letter, technical Annexes Part two https://www.ofgem.gov.uk/publications-and-updates/riio-2-draft-determinations-transmission-gas-distribution-and-electricity-system-operator

[15]https://www.ofgem.gov.uk/system/files/docs/2019/10/gad_assurance_report_-_specified_street_cost_reopener_assessment.pdf

Name	Mechanism	RIIO-1 Comparison	ENWL Comments
Cross-sector mechanisms			
Ofgem licence fee	Pass-through	No change proposed	We agree with the retention of the mechanism and the design used in RIIO-ED1.
Business rates	Pass-through	No change proposed	We agree with the retention of the mechanism and the design used in RIIO-ED1.
Inflation indexation of RAV and allowed Return	Indexation	Revised for RIIO-ED2	Please see answer to Finance Annex question FQ15.
Cost of debt indexation	Indexation	Options for change proposed	Please see answer to Finance Annex question FQ1.
Cost of equity indexation	Indexation	New for RIIO- ED2	The mechanical attempt to introduce indexation into the equity allowance has pitfalls. Equity investors into UK infrastructure provide patient capital and seek long-term stable returns. While indexation may seem attractive to regulators, adjusting CAPM for short term fluctuations for risk-free rate in isolation is an error and provides a false sense of precision in the output, while also being disjointed from the expectations of investors, which are forward looking and long-term. Ofgem's approach introducing equity return variability increases the risk and therefore the required return level. Following the revision to five-year price controls, we do not believe equity indexation is either a necessary or a positive development for networks or consumers.
Real Price Effects	Indexation	Revised for RIIO-ED2	Please see our answer to Q16 of this document.
Tax review	Re-opener	New for RIIO- ED2	Please see answer to Finance Annex question FQ13.

Name	Mechanism	RIIO-1 Comparison	ENWL Comments
Pensions adjustment	Pass-through	Revised for RIIO-ED2	There seems to be an inconsistency between table 7 and that stated in chapter 11 of the Keeping Bills Low annex. Clarity is needed as to whether this mechanism is to stay as it is in RIIO-ED1, or that it is to be revised and, if so, what the proposed revisions are.
Enhanced Physical Site security	Baseline allowance and/or re-opener	No change proposed	See our response to Q55 of the Value for Money annex for more details.
Cyber resilience	Baseline allowance and/or re-opener	New for RIIO- ED2	See our response to Q47 of the Value for Money annex for more details.
Net Zero	Re-opener	New for RIIO- ED2	See our response to Q3 of the Overview annex for more details.
Coordinated Adjustment Mechanism (CAM)	Re-opener	New for RIIO- ED2	See our response to Q27-29 of the Overview annex for more details.

Name	Mechanism	RIIO-1 Comparison	ENWL Comments
Specific to RIIO-ED2			
Strategic investment/Load related expenditure	Dependent on Model for strategic investment: could include volume drivers and/or reopener	New/reformed for RIIO-ED2	We agree with the proposal to revise the arrangements for load related expenditure from the existing mechanism which is in place for RIIO-ED1. The regulatory framework must enable DNOs to deliver anticipatory/strategic investment without undue regulatory barriers, whilst companies must equally ensure that their decision making is supported by robust and transparent data and made with the best information available at the time. We provide more detailed comments on the options presented in our response to Annex 3 of the Overview document.
Street works costs	Re-opener	No change	We agree with the retention of the mechanism and the design used in RIIO-ED1.
Rail Electrification	Re-opener	Reform for RIIO-ED2	We agree with the proposals.
Black start	Re-opener	New for RIIO- ED2	See our response to Q54 of the Value for Money annex for more details.

Name	Mechanism	RIIO-1 Comparison	ENWL Comments
Miscellaneous pass-through	Pass-through	No change	It would be helpful for Ofgem to list what is currently intended within this category to ensure there is no misunderstanding. The statement of "no change" implies that the items listed in CRC 2B of the Electricity Distribution licence remain as pass-through. We believe it is Ofgem's intention to continue with pass-through arrangements and we agree these should include all those items in the list provided[16] as well as the following which are included in CRC2B but missing from the consultation: • Supplier of Last Resort Costs • Eligible Bad Debt Costs In addition, all transmission connection point charges should be pass-through whether they are existing or new
Smart Meter interventions	Volume driver	No change	We agree with the continuation of a volume driver to manage the uncertainty over timing and volume of Smart Meter Roll-Out costs in the same way as was applied during RIIO-ED1. There is no requirement for a tapering factor given the percentage of DNO interventions to supplier installations are better known with less volatility.
Environmental legislation	Re-opener	New for RIIO- ED2	We agree with the potential inclusion of an Environmental Legislation re-opener. This should be tightly designed as per our proposals shared in Q60 of the Value for Money response.

[16] 11.29, keeping bills low for consumers, Ofgem

Q38 Are there any other uncertainty mechanisms that we should consider? If so, how should these be designed?

Many of the re-openers displayed in table 7 have been developed to enable companies to respond to external factors which are beyond companies' control for example Black Start Standards, CNI sites, Cyber framework. Should there be a scenario where other external bodies, remote from Ofgem and DNOs, gain control of standards or compulsory activities which ultimately result in a material change to DNO activities and costs then a new re-opener mechanism may need to be created.

Company specific mechanisms should be allowed, and these should be assessed as part of the business plan submissions at Draft and Final Determinations stages, such as our mechanism for Moorside in RIIO-ED1 which we are reviewing for its continued requirement in RIIO-ED2. Some company specific mechanisms will potentially arise from customer and stakeholder engagement and other developments which occur between now and the business plan submission milestones.

Considering innovation, Ofgem should reflect whether a mechanism that supports the rollout of projects that are of benefit to consumers but at additional cost to network companies (when compared against BAU approaches) is required. It is a gap in Ofgem's proposals at present as without such a mechanism, any innovations that could be rolled out, where they cost more than traditional solutions but have a net consumer benefit, will have to wait to the next price control period for this to happen. We set out more detail in our response to Q10 of the Overview document.

Q39 Do you agree with our proposed removal of the above uncertainty mechanisms for RIIO-ED2?

We agree that load related expenditure (LRE) should be removed and replaced with a new mechanism for RIIO-ED2 and have proposed our own solution to LRE which has been developed in collaboration with the majority of DNOs, namely 'the Capacity Volume Driver' (see Q9 of the Overview annex for our detailed response to this). To enable decarbonisation a substantial level of ex-ante allowances should be provided as well as an uncertainty mechanism.

With regards to the other mechanisms, we agree with the complete removal of the UM relating to Link Boxes.

Subsea Cables is an example of company specific UM and so we do not comment as to its retention or removal. However, company specific UMs, where justified, should continue to be allowed.

Q40 Do you agree with our proposed common approach for re-openers being applied to RIIO-ED2?

Our position for ED is that any mechanisms for managing uncertainty, including re-openers, should be clearly defined and targeted in their use, as well as being less extensively used in ED compared to GD/T due to the differences of our sector.

The most critical process consideration for re-openers is that Ofgem will need to be able to make material decisions much more rapidly than today's processes and based, relatively speaking, on incomplete information in a faster changing world. Greater transparency from Ofgem, laying out the basis it intends to take decisions, will enable companies to react quickly to emerging needs and challenges as set out in the framework re-openers. The ability for Ofgem to act quickly is crucial to ensure that Ofgem itself doesn't inadvertently become a blocker to decarbonisation and decentralisation of the energy system.

A common approach has a benefit of being clear and easy to understand where this is to apply in most of cases. However, we have concerns with the proposed approach for each of the parameters as set out in the extract table from the SSMC below.

Re-opener parameters	Consultation position
Re-opener application windows	Bring forward re-opener application windows from May to January. Reduce re-opener application window from one month to one week (ie last week of January).
Application requirements	Provide additional detail and guidance where possible in licence conditions and guidance.
Authority triggered re-opener	Authority can trigger a re-opener at any time during price control.
Materiality threshold	For each individual re-opener application, set a materiality threshold such that we will only adjust allowances if the changes to allowances resulting from our assessment, multiplied by the TIM incentive rate applicable to that licensee, exceeds a threshold of 1% of annual average base revenues (as set out in Final Determinations). Allow for aggregation of some re-openers subject to specific criteria.

Taking each of the elements in turn:

- **Re-opener application window**: Any potential increased use of UMs and re-openers will result in increased regulatory burden and this should be considered when making any changes to application windows or timescales, as well as the overall balance and use of UMs and re-openers for ED. By bringing forward the application window from May to January, it is clear the only benefit is a longer assessment time for Ofgem, however, this is not consistent with the need for agile and timely decision making as the speed of decarbonisation and the pathway to Net Zero becomes clearer. Consumers and industry need a quicker and more appropriate approach to re-opener decisions given the large number of decisions Ofgem has positioned itself to make. It is unlikely to be sustainable without an overhaul to the decision-making processes.

- **Application requirements:** We support the clarification and proposal to provide additional guidance to companies and all stakeholders. We also agree with the proposal to consult on the guidance and any subsequent amendments, before it comes into effect, but this must be done before the price control starts and ideally should have been done before Business Plan submissions. We would urge that this guidance and requirements on companies is proportionate and cognisant of the impact on the regulatory burden placed on companies and Ofgem. Its aim should be to support key objectives and not slow down the process such that regulatory requirements become a barrier to the industry in delivering essential activities under decarbonisation, Net Zero, or other considerations. Guidance should be clear and set out the requirements to ensure companies are aware of the criteria to which the authority “may reject any re-opener application that does not contain all the information necessary for us to make an informed decision on the contents of the application”17 as set out in 11.45. As much as possible companies and stakeholders need to understand the basis and approach of Ofgem’s decision making so that the presented proposals from the companies align with Ofgem’s expectations and views.

[17] RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, 11.45, Ofgem

- **Authority triggered re-openers**: We think that this parameter should apply only to a small number of re-openers with defined windows, where consumer benefit can be demonstrated and not be applicable to any or all re-openers by default. We have concerns that this will increase uncertainty on companies, thereby raising risk and costs for consumers in the long run.

  The process for triggering re-openers should be the same for both Ofgem and companies in terms of certainty and clarity as to what might be triggered when. This isn't the case as it stands in proposals where the Ofgem can trigger at any point. Certainty and clarity underpins good regulatory practice. An open-ended asymmetrical process does not provide this to companies and stakeholders alike.

- **Materiality threshold**: We support the flexibility to aggregate re-openers where there are items that don't meet materiality on their own. It is unclear on reading the SSMC and the DD documentation precisely which re-openers are and which are not eligible for aggregation. We would urge that a clear table is produced showing each re-opener and the associated parameters. It is also not clear why a higher or even a different materiality threshold should apply to aggregated items[18]. By the Ofgem definition a materiality threshold "provides a balance to ensure network companies and consumers are protected from significant variations in expenditure over the price control"[19] There should be no difference between a single item materiality threshold and an aggregated claim where appropriately evidenced and justified against the relevant criteria. Also, applying the company specific sharing factor (TIM) has the same effect of changing the level of significance between companies. A lower TIM for RIIO-ED2 also has the result of increasing materiality from RIIO-ED1 levels, which is inconsistent with a lower risk price control. Under a lower risk, lower returns price control it would be a surprise if materiality thresholds increased. A flat percentage of allowances, reviewed in the round to ensure risks are not increasing for companies with lower returns, would be simpler and not create differences in what is or is not significant between companies.

10 Increasing competition

Q41 Do you agree that our flexibility proposals are sufficient to incentivise DNOs' native competition?

We agree that the TIM provides a sufficient incentive for DNOs to seek innovative solutions to mitigate a network need, and we see no need to bring in additional targeted formal arrangements. DNOs are already committed to explore flexibility first as per the agreement through the ENA[20], and the DSO principles, as proposed, apply greater clarity to companies as to Ofgem's expectations in this area.

As part of the RIIO-ED2 price control discussions ENWL proposed a capacity volume driver for load related expenditure that would facilitate the increased use of flexibility services as network operators work to deliver the capacity requirements of network users at the lowest costs. The design of the capacity volume driver is complementary to the TIM and seeks to achieve this by using capacity

[18] RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, paragraph 11.58, Ofgem, gives the example of 3% compared to 1% for single item re-openers.
[19] RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, paragraph11.56, Ofgem
[20]https://www.energynetworks.org/assets/files/ENA%20Flexibility%20Commitment%20Our%20Six%20Steps%20for%20Delivering%20Flexibility%20Services.pdf

requirements to drive funding, but not specifying the solution whether that be either traditional network or flexibility service, as the company will select the optimal solution for customers.

Flexibility gives advantages in situations where there is uncertainty in forecasts; flexibility could increase costs in the short term but avoid stranded assets if the lower forecasts are realised.

Q42 Do you believe there are similarities between DNOs running early competitions and the roles and activities that may be related to electricity DSO functions?

Within Ofgem's classification of early competition in the consultation there appears to be no similarities identified with the functions under DSO. We would argue that the timing associated with the early competition model is exactly the same as the procurement of flexibility services as an alternative to traditional reinforcement (i.e. when we identify a need we look into potential solutions) which includes the tendering for flexibility services.

As we share more network data, embracing data as a key enabler in RIIO-ED2, we fully expect that stakeholders will identify areas of the network that will have a potential future need and highlight this to us in conjunction with offering to provide the solution.

Q43 Do you agree with our proposed approach on early competition?

We support competition, innovation and enabling new forms of service provision by new parties. This is evidenced by the fact that we were assessed as having enabled the most competition in connections of any DNO at the start of RIIO-ED1.

We already utilise both early and late competition type models where currently appropriate, such as:

- All our load related proposals seek flexibility alternatives adopting the flexibility best practice established by the ENA (early competition)
- We tender all our framework contracts, and comply with OJEU rules as set out earlier (late competition)
- Certain construction projects are also competitively tendered to ensure best value (late competition)

We employ this approach and apply it to all our supply chain. Further, we utilise tendering and competition testing extensively on our procured expenditure with circa 80 percent covered by competitively secured framework agreements and more on top of this tested separately through one-off competitive processes. We understand that every pound we spend is funded by consumers and as such we are targeting to increase the percentage we test in RIIO-ED2 from our already strong current position in RIIO-ED1.

These examples demonstrate how we utilise and support competition where appropriate and in the best interests of customers, and will continue to do so in the future, however we do not support artificially creating competitive processes which increase costs and risks where there is no customer benefit in doing so.

To bring benefits for consumers, both in the ENWL region and nationally, we developed CLASS that provides services to the ESO. This is meeting the operational needs of the ESO multiple times a day, which in turn mitigates the risk of power cuts such as that observed on the 9th August 2019.

Additionally, we apply a contestability test for market testing of flexible services for network reinforcement. The test is “is the reinforcement requirement greater than 200kVA and greater than £200,000”. The ENWL network is well managed, with capacity available on our network in many areas of the region, so, whilst our volume of accepted flexibility tenders is lower than some DNO groups, our commitment to flexibility markets is equal to or stronger than other DNOs.

It is clear from the above that early competition is already embedded in our business as well as the ED sector overall and we suggest that any additional requirements based on those set out for GD and T would represent a disproportionate tool for ED given that the additional consumer benefit is unlikely to outweigh the additional costs incurred. We also note the work being undertaken by the ESO on the Early Competition Plan (ECP) for ET. We understand that the applicability of the ECP to ED is being considered but we question what additional benefit this would bring beyond that already being delivered by DNOs, facilitated by Ofgem’s existing framework, in RIIO-ED1. We further understand the timing of this work to be February 2021. This timing in consideration of the Business Plan submissions is too late, assuming review and conclusions need to be drawn by Ofgem after this date of publication.

We suggest Ofgem focusses on the marginal consumer benefit of any competition policy changes within ED and carefully quantifies these for ED specifically as well as assessing the costs. The scale, separability and length of development (i.e. early sight) of Transmission projects, along with all the work done over the last five years or more, suggests that it is more important to focus on Transmission for the early competition model to learn and develop the model further. There currently is not enough detail provided as part of this consultation to see how the model could work as it still seems to be at conceptual stage. We are not clear that the model for Transmission is the right starting point and much work could be needed for ED to introduce early competition that looks like the approach(es)/model(s) for Transmission. Additionally, an early model of competition already in place, and working in ED1, is where the DSO tenders load related reinforcement to potential service providers, be this flexibility providers or other innovative solutions. We are solution agnostic where proposals meet our customers’ needs for reliability, resilience, safety, customer service and cost. RIIO-ED1 and, we expect, RIIO-ED2 will provide us with strong incentives to find the most cost-effective solutions for consumers, continuing to drive this sort of early competition for distribution solutions.

Having looked at Ofgem’s information presented in the consultation, we are concerned that the threshold for early competition projects is proposed at projects in excess of £50m. Our view is that this is a disproportionate tool considering the consumer benefit for ED and noting the costs of competitions themselves contained within Ofgem’s impact assessment. We suggest the threshold for both early and late competition should be where the value is in excess of £100m. Further, having looked at the potential costs, projects might need to be much higher value than £100m to deliver net benefit to consumers. Early competition models might be applied when there is significant uncertainty associated with the project so to be confident the benefits outweigh costs a higher threshold might be especially relevant for early competitions.

The way Ofgem is consulting on the same competition models and approaches for ED as for Transmission doesn’t align with ED having a separate process. There is a risk as a result that Ofgem’s process leads to a sub optimal outcome for consumers and stakeholders. It would seem that Ofgem assumes perceived issues in transmission equally apply to distribution without specific consideration of how ED is different to the ET sector.

Q44 Do you have any views on our draft RIIO-ED2 Late Competition Impact Assessment?

The impact assessment came out part way through the consultation period though it is heavily based upon the Transmission models and their justification. Of the late competition models, we support the CADO model, as we do not see any circumstances where an SPV model would be a preferable to CADO. We cannot see a case for developing the SPV model further, as Ofgem does not set out any advantages of this model for consumers over and above the CADO model, and we can see SPV will be extremely difficult to implement.

The costs of running the competition look low to us. We also disagree that failed bid costs will never come back to customers. With each bid having a multi-million pound cost, over time, we expect bidders to need to recover their costs of bidding, or they will quickly stop engaging if they continue to be unsuccessful. Either way there is a cost of failed bids to the economy and so Ofgem should not just assume this away.

The impact assessment on late competition underplays the work needed on, and challenges of, managing distribution networks under RIIO-ED2 with complex regulatory arrangements especially if other network providers become key parts of delivering a reliable and safe electricity provision to consumers. For example:

- Arrangements for customer service and interruptions incentives; how would a customer differentiate between an issue caused by the monopoly or a CADO?
- Overheads for stakeholders of needing to work with a CADO/SPV; and
- Additional costs of CADOs/SPVs needing to undertake activities such as DSO.

The impact assessment does not set out how new connections will be managed under each of the potential new delivery models. With decarbonisation a key government aim, the ability to change existing assets and connect new assets needs further specific thought as to what obligations CADOs and SPVs would have.

Should any late (or early projects be identified in RIIO-ED2) then impact assessment(s) will need to be done for each specific project.

To an extent Ofgem's approach to RIIO-ED2 is really a competition proxy model on a grand scale. With paragraph 12.26 of the Keeping Bills Low annex referring to the perceived benefits of competition cited as allowing efficiencies through:

- *Establishing and locking in long-term debt and equity rates, as well as gearing, that reflect current market rates for financing a project:*
  Developments in the RIIO-2 framework should look at fair debt and equity rates and the right gearing to reflect efficient market rates and Ofgem is undertaking this anyway for the whole networks sector.
- *Establishing economic and efficient capital and operational costs that reflect current market rates:*
  This ought to be where Ofgem seeks to get to and we support Ofgem achieving this for RIIO-ED2.
- *Enabling efficient costs for a project through a project-specific risk allocation:*
  This can be achieved through the various licence mechanisms such as uncertainty mechanisms and re-openers.

Therefore, we don't think the competition proxy model would deliver additional benefits to consumers if the RIIO-ED2 price control is set appropriately. Additionally, the way Ofgem is consulting on the same competition models and approaches for ED as for Transmission doesn't align with ED having a separate process. There is a risk as a result that Ofgem's process leads to a sub-optimal outcome for consumers and stakeholders.

Q45 What are your initial views on the three models of late competition (CATO/CADO, SPV and CPM) in the context of electricity distribution? If there would need to be differences from the other sectors, can you please explain what these should be, and why.

Our initial view is that:

- The CADO model is relatively more suitable than other models. Since we already have IDNOs and ICPs competing effectively to provide distribution services, Ofgem should consider specifically how these models compare, contrast and what, if any, impacts their existence has on the late competition models relevant for ED. Equally Ofgem might find that changes to IDNOs and ICPs are needed;
- SPV would be very difficult to implement and doesn't have particular customer benefits to commend it over CADO; and
- CPM from its description sounds like it seeks to achieve what Ofgem is targeting for customers for RIIO-ED2 more generally, and so seems likely to be irrelevant for ED.

We and other DNOs are actively market testing flexibility which already gives a route for competition. How this can complement any potential late competition should also be considered.

Q46 Do you agree that the late competition models proposed could deliver benefits in RIIO-ED2?

We support using competitive forces and utilise them ourselves to secure innovative solutions and best prices for customers. This, and the DNOs expansion to include flexibility solutions alongside traditional asset-based solutions, when combined with Ofgem's approach to setting a stretching RIIO-ED2 framework, means that there is little or no ability for late competition models to deliver additional benefits to consumers.

We question the relative priority of work to introduce late (or early) competition models when the opportunity cost for customers of developing these models might be less progress on key areas such as decarbonisation and reliability.

Q47 Do you agree that our proposed criteria for identifying projects suitable for late model competition are applicable in the context of electricity distribution?

As set out by Ofgem the high-level criteria of; new, high value (£100m or more) and separable, are a suitable starting point to undertake a bespoke benefits/cost assessment on a specific larger project basis. The threshold of £100m may in fact be too low given that the potentially lower financial parameters for RIIO-2 compounded by more challenging base cost allowances could in turn erode or negate any potential cost savings from other parties.

Q48 What are your views on the best ways to identify a suitable project pipeline for late competition in electricity distribution (eg our proposal to require flagging of projects that meet the high-value, new, and separable criteria)?

Should Ofgem progress with late competition in RIIO-ED2 it would be sensible to request that DNOs include potential projects meeting the relevant criteria in their business plans. This will require a clear decision on the criteria in good time (by March 2021) to enable the relevant projects to be listed in time for final Business Plan submission in December 2021.

Q49 Do you agree with the proposed range of options available for repackaging projects in RIIO-ED2 in order to maximise consumer benefit?

Whilst repackaging should be thought about, its deployment needs to be carefully considered. We can foresee circumstances where existing assets might be efficiently bundled with new ones as part of a project, though repackaging should only be undertaken with bespoke consideration of the specific circumstances.

Q50 What relevant factors do you think we should consider in deciding how these repackaging proposals are specifically applied in electricity distribution?

The repacking proposals should be focussed around net benefit to consumers. The proposals are very high-level as set out and don't really include any insights as to how they might be applied to ED. We look forward to reading and reflecting on the responses received when these are published.

11 Incentivising ambitious Business plans and their delivery

Q51 Do you agree with our proposed approach to implementing the CDIR method in setting the TIM efficiency incentive rate?

We understand the approach that Ofgem is taking with regards to the CDIR in setting TIM, although we have some concerns with the approach taken.

Firstly, we are pleased to observe the TIM sharing rates as part of the DDs. Sharing factors at 50 percent represent a relatively fair and balanced position, and reflect good regulatory precedence as acknowledged by Ofgem in the SSMC[21]. Due to the increased number of comparators in ED a sharing rate of 50 percent should be the outcome rather than those observed in transmission.

It is concerning to see the proposed rate for transmission companies and should this be the outcome for ED it would risk a significant impact on the sector's ability to deliver Net Zero and the increased investment required to deliver this crucial policy objective. This is because a strong TIM sharing rate reveals more innovations and cost reductions in that period. It becomes harder to find or replicate these in future periods and subsequent price control reviews – therefore the strength of TIM needs to be increased rather than diminished.

[21] RIIO-ED2 Sector Methodology consultation: Annex 2: Keeping bills low for consumers, paragraph 13.9, Ofgem

In RIIO-ED2, with a 5-year price control, we do think Ofgem needs to consider the benefits that come from sharing factors in excess of 50 percent as this will ensure the strength of the incentive to enable investment in initiatives in a shorter control so there is adequate payback. Lower sharing factors in RIIO-ED2 than in RIIO-ED1 are likely to result in slower progress in driving savings than RIIO-ED1 experienced.

Our principle concerns stem from the blended nature of the sharing factor and how this interacts with highly ambitious and innovative business plans which may include a number of first mover or leading edge innovative projects that have, potentially, relatively more uncertainty than activities that have been done historically, but in our view do have robust evidence, potentially gained through the IRM. The cornerstones of RIIO, namely *innovation* and *incentives*, need to be complementary and not work in contradiction to each other and companies should not be penalised for being ambitious and innovative by facing lower potential benefit from lower sharing factors. A blended sharing factor and a lower TIM risks companies reining back innovation and ambition in business plans where there is a chance these are assessed as low confidence costs.

We note that there are proposals for how costs can be justified or evidenced to be assessed as high confidence, although we urge that more detailed guidance is provided and developed in collaboration with DNOs. Transporting these straight from GD/T without consideration to the unique circumstances of ED is sub-optimal. We welcome a request to increase the scrutiny and robust analysis of company plans but this should not treat innovation unfairly through TIM and should actively encourage innovation rather than discourage it.

Q52 Do you agree with our proposed design of the BPI for RIIO-ED2?

Whilst the design of the BPI is reasonably clear, how Ofgem implements it in practice is not. From what we have observed of the implementation in the early RIIO-2 sectors, we are concerned that unless there are changes made for the application of the approach within RIIO-ED2 that there is a real risk of the BPI becoming a skewed incentive where companies only aim to avoid significant downside penalties. In turn the BPI could reduce companies' ambition, where compliance with the guidance and avoiding the substantial downsides seen in GD/T is the goal, thereby reducing the potential for stimulating positive outcomes for consumers.

For clarity we provide comment on each stage in turn:

Stage 1 and 2: From observing the GD2/T2 process and reviewing the recent DDs, it is clear that there has been a lack of understanding and clarity between companies and Ofgem surrounding the BPI and the process of its assessment. During industry discussions and workshops there has been ongoing uncertainty over the CVP element of the business plan guidance and this has manifested itself in the outcome and assessment of the DD proposals.

Whilst some of the issues may have been a result of the iterative approach to Business Plan Guidance, there has also been a disconnect between Ofgem's expectations and companies' understanding that resulted in a large number of CVP proposals, yet a very small number meeting the criteria, and even fewer considered worthy of award. It is clear that CEGs and stakeholders have also had a lack of understanding of Ofgem's expectations, as CEG's supported the business plans submitted in many cases, though Ofgem issued penalties to most. It is critical that these lessons are learned and are resolved for the RIIO-ED2 process so that both DNOs, their CEGs, stakeholders and Ofgem can have a more positive experience, underpinned by clearer guidance on expectations and method of assessment. Therefore, we welcome the greater clarity and guidance provided as to the approach to

BPI and CVP for RIIO-ED2, and that this is being consulted on as part of this SSMC. We do have some concern that the guidance can easily become too prescriptive and not allow appropriate flexibility to reflect customer and stakeholder preferences and priorities, and we set this out in more detail in our response to Q54 of this document.

Stage 3 and 4: As discussed in more detail earlier in Q51, greater clarity is also required as to how high and low confidence costs will be determined. Given that no company in the GD/T DD was provided with a reward in stage 4 it would be helpful for Ofgem to provide a worked example so that companies can better understand how this stage is expected to work.

We welcome Ofgem's acknowledgement that greater clarity is required in this area, and the consultation and associated guidance goes some way towards this. However, we would urge that dialogue on this important subject continues between now and the decision point in December 2020 via the formal working groups so that all stakeholders and companies can be clear on how this will work for ED in order to ensure maximisation of quality and ambition of business plans to deliver the best outcomes for consumers. These discussions should walk through each stage of the BPI and the interaction within and we suggest this is done at OAWG.

Q53 What are your views on our suggestion to use proposals contained in draft business plans in the setting of baseline standards in a number of areas (as discussed in paragraphs 13.28 and 13.29)?

It is our position that baseline standards and any potential adjustments to these between Business Plan submissions should represent minimum standards, and that companies can go beyond these where justified through stakeholder and customer engagement. Anything imposed beyond a common minimum standard would risk disconnecting the requirements on companies from that agreed with stakeholders and consumers as part of enhanced stakeholder engagement.

Caution should be applied where companies submit deliverables and outputs that exceed baseline expectations and where these are considered for wider adoption by the industry. This could undermine customer and stakeholder engagement if incorrectly applied. It is not clear within the consultation, or the Business Plan Guidance, precisely what Ofgem's intention is in terms of the draft Business Plans to be submitted by DNOs in July 2021. Throughout the documents there are a number of references that the July submission will be to the RIIO-2 Challenge Group and the December submission to Ofgem. However, within this and other sections, there is the intimation that Ofgem will use the July submission to consider CVP and baseline standards. It is critical to gain clarity as to Ofgem's intent in this area.

As with each business planning cycle there is a natural tension between collaboration and competition between companies. The BPI is designed to drive companies to reveal best practice, cost efficiency and high ambition levels, which naturally brings an element of competition. However, the need to determine common standards, methodologies and performance metrics, combined with the requirements under the Enhanced Stakeholder Engagement Guidance to ensure plans are co-created and well tested, means that companies need to collaborate and be open with their draft plans, strategies and consultative process. These two requirements are not naturally compatible and introducing a further layer of Ofgem assessing draft plans with a view to re-setting baseline standards may result in a reluctance for companies to share their plans and risk a reduction in the collaboration and engagement that Ofgem's process is seeking to strive.

Equally, consideration needs to be given to the intent to use what may be an unfinished plan to require adjustments to other company plans and the consequences of such an approach.

The Enhanced Stakeholder Engagement Guidance which we are implementing thoroughly, ensuring our business plan is shaped by our customers, will lead to our plan having standards and services within it for the North West and regions within it. What our customers and stakeholders want, prioritise and are willing to pay for will be different to those in other DNO areas so it is important Ofgem doesn't use this process to undermine local engagement outcomes.

Finally, given that there is only a period of five months between the two business plan submission dates, and at least one to two months of that time would be used by Ofgem Challenge Group considering the July plans, this gives companies limited time to consider what impact revised baselines will have on their plans and costs, and may not allow sufficient time to re-test such baselines with their stakeholders. Companies will also need to consider whether their customers have expressed a view about total bill impact to ensure an affordable settlement in the round plan.

Whilst we agree with the concept of baseline standards in some areas to ensure that no region is disadvantaged on standard services, this should be focussed on minimum standards, not raising them to the highest standards of all offered, and there is also merit in providing companies with the ability to propose a level of service that is appropriate for their region given its unique characteristics. Therefore, a one size fits all approach may not be appropriate for all activities, DSO for example being one of these.

Q54 Do you agree with our proposal to cap the number and value of CVP proposals that can be included within business plans

Whilst we welcome the clarity on the topics suggested for CVP proposals, we do not believe that Ofgem should limit the ambition of companies by constraining proposals solely to these topics. We recognise that Ofgem wishes to ensure that there is a clear signal for the areas where it would like companies to focus, however, this makes areas outside of these topics ineligible for a reward, even if backed by robust customer and stakeholder engagement. We would suggest that Ofgem keeps sufficient flexibility to allow for companies to put forward proposals outside of the five areas on a comparable basis that are eligible for rewards, where prioritised and valued by customers and stakeholders. As we propose in our cover letter, areas such as Smart Street and leading decarbonisation should be included in the list of areas to be included.

With regards to a cap on values, quantity of CVP proposals and overall cap, we also believe that this approach in combination will fetter ambition and should be reconsidered. DNOs are working together collaboratively on a convergence project on Social Return on Investment (SROI) and how this can be standardised across DNOs, building on the work done for SECV in RIIO-ED1. We urge that Ofgem considers the output and progress of this project and how this can enhance CVP assessment for RIIO-ED2.

As referenced in the previous question (Q53) we would also like to obtain clarity on Ofgem's intention on the CVP assessment between draft and final business plan submissions.

Q55 Is there any further detail on the proposed content of the Business Plans that you think should be set out in the Business Plan Guidance?

We currently do not have any specific examples of further detail required in the Business Plan Guidance other than in the description of Price Control Deliverables where Ofgem refers to 'baseline funding'. This term is also used three times in the SSMC documentation, but there is no clarification of what this means. It would be helpful for this term to be clarified to aid in fuller understanding.

It is clear that, as the requirements evolve over the next few months in areas such as for CBA and EJP, supplemental detailed guidance will need to be published reflecting the agreed process changes.

We expect that further detailed discussion on the Business Plan Guidance will also take place within the RIIO-ED2 working groups and that any content or clarification points will be addressed within that forum as well as via this specific consultation.

Q56 Is there other information that we should be requesting in the Business Plan Guidance in order to assess a network company's Business Plan?

We are not aware of any material gaps in the Guidance subsequently issued by Ofgem, however, we will continue to work with Ofgem through the RIIO-ED2 working groups such as the BPDT Working Group to highlight these as and when they are identified.

Q57 Do you agree with the proposed set of minimum requirements for Stage 1 of the BPI that are set out in the draft Business Plan Guidance?

Through our observations of the RIIO-2 business plan process for GD/T we note that, despite the minimum requirements in the section being similar to those drafted for ED, four out of the eight companies were deemed to have not met the minimum requirements. We are unsure where the failing lies in this, as no company should fail to meet a set of clearly laid out minimum requirements. We ask that Ofgem provides more detail on how this was assessed and where the minimum requirements were not met, with examples, so that the lessons can be learned to ensure that no such failing occurs for ED companies.

Further, it is unclear from the document whether these minimum requirements apply solely to the business plans submitted to Ofgem in December 2021, and what, if any, requirements there are for the initial plans due to be submitted to the RIIO-2 Challenge Group in July 2021. It would be helpful to clearly state in the guidance this applicability.

We have no further comments on the list of minimum requirements at this point and will continue to work with Ofgem to develop the guidance through the Ofgem working groups.

Finally, section 8.7 final paragraph states "*and must also have regard to the guidance given in Section 4 of this document on the presentation and structure of Business Plans*." This should be corrected to point to section 7 which is the section referring to presentation and structure of plans.

Q58 Do you agree with the approach for assessing companies CVP proposals that is set out in the draft Business Plan Guidance?

As we share in our response to questions 52 and 54 we have some concerns over the level of prescription within the CVP proposals. We do not believe this is in consumers' best interests and could have the effect of fettering companies' ambition and focus on the range of customer and stakeholder needs emerging from enhanced engagement. We would suggest that Ofgem keeps sufficient flexibility to allow companies to put forward proposals outside of the five areas on a comparable basis, where prioritised and valued by customers and stakeholders.

With regard to a monetised benefit methodology, DNOs are working together collaboratively on a convergence project on Social Return on Investment (SROI) and how this can be standardised across DNOs building on the work done in SECV in RIIO-ED1. We urge that Ofgem considers the output and progress of this project and how this can enhance CVP assessment for RIIO-ED2.

Q59 We anticipate that DNOs are investing in improving / creating data dictionaries and business information models that describe the data-driven aspects of DNOs overall business architecture. We anticipate there may be opportunities to take advantage of these investments to support the process of cross-referencing data used within RIIO-ED2 Business Plans. What are your views on this?

Data integrity is a key part of assessing the quality of DNO Business plan submissions and we will be using approaches, such as those outlined, to ensure that our submission is appropriately cross-referenced.

Sector Specific Methodology Consultation response

Annex 4: Finance

September 2020

Contents

1 Allowed return on debt questions

FQ1. Do you agree with our proposal to use the iBoxx Utilities 10yr+ index rather than the indices used in RIIO-1?

As a general point of principle, we continue to have concerns over a one-size fits all approach to setting the debt allowance. A full indexation methodology, calibrated to the expected sector debt costs, will provide cross-generational outperformance to those 'lucky and large' networks, while perpetuating financeability headwinds for others.

We believe that the suitability of any approach is best measured with respect to its outcomes. Ensuring the financeability of individual networks, through the re-distribution of the sector debt allowances towards those networks with higher embedded debt costs, would provide significant benefits over the current approach without additional costs for UK consumers.

We recognise the concerns raised previously in respect of any straight pass-through of debt costs, and although we continue to believe it is more appropriate than the full indexation approach, we also believe a modified approach that provides individual networks with pass-through of embedded costs only, can deliver incentivisation for new financing, while also protecting consumers interests through debt efficiency tests in Business Plan submissions.

With respect to estimating debt costs, either under the proposed or any alternate approach to setting the debt allowance, we raise the following points of principle:

- The cost of derivatives should be included in any estimation. A key function of derivatives is risk management. To the extent that the efficiency of derivatives cannot be understood simply, networks should be asked to provide additional information.
- We support the inclusion of all areas of financing – including transaction costs, liquidity management and pre-financing.
- To the extent that networks are exposed to RPI basis risk on financing following Ofgem's decision to move to CPI or CPIH, the efficient cost of hedging this risk should be included in the estimation of debt costs.
- Intercompany loans are not simple and should be considered for inclusion on a case-by-case basis.
- If it can be demonstrated that some networks suffer structurally higher financing costs, such as from being an infrequent issuer in capital markets, then the additional costs should be included for that network.
- Incorporating additional sectors into any calibrated average will accentuate the issues noted above, while providing minimal benefits to consumers.

Providing that the primary objective holds - being to reimburse the estimated sector debt costs - the choice of reference index is of reduced importance, as any resulting allowance can be structured to be largely equivalent through the use of a wedge or a deduction. While such adjustments can be justified by reference to transaction costs, the halo effect, or similar, this process of justification is less critical than that of delivering on the primary objective and reimbursing networks with the appropriate allowance.

We do not have a view at this stage on whether the Utilities index is ultimately more appropriate, but we look forward to working with Ofgem as part of the ENA Finance Working Group to understand the relative benefits and weaknesses of the proposal.

We note that the period covered by any index, and whether a constant timeframe or tromboning structure is adopted, is of arguably more importance than selection of the base index. If this structure is inappropriate, the allowance will not accurately match the refinancing profile of networks and would also expose those networks to significant underperformance in the event of any rate reversion.

This risk could be reduced through the adoption of a modified pass-through approach.

The RIIO-ED1 approach to setting the debt allowance has resulted in skewed and unfair rewards, purely down to exogeneous factors that systematically penalise some companies and reward others. Ofgem should ensure that the RIIO-ED2 approach is fit for purpose long-term, supporting inter-generational policy-making and providing the stability that should be the cornerstone of an effective regulatory framework.

As previously mentioned in our response to the RIIO-ED2 Open Letter, Ofgem should undertake a stress tested impact assessment on how the debt allowance will impact individual company financeability. It should be carried out before finalising the RIIO-ED2 approach and ensure that it conforms to Ofgem's financeability duty.

FQ2. With reference to paragraph 2.8, do you have a view on what debt allowance calibration should be used for business plan working assumption purposes, and why?

While we continue to believe that a full indexation methodology is inappropriate for RIIO-ED2, for the purposes of business plan working assumptions, we support an assumption based on RIIO-ED1 (10-20 year trailing average). This methodology was calibrated for distribution networks previously and the annual RFPR reporting demonstrates that it is a reasonable proxy for sector average debt costs as a whole. The financing costs of GD&T companies are not necessarily comparable to those in the ED sector and using that calibration may be overly distortive, particularly in the context of financeability assessments.

Adopting the GD&T calibration without adjustment would embed a structural sector-wide debt underperformance for DNOs in RIIO-ED2. As part of the Sector Specific Methodology Decision (SSMD), Ofgem must give a firm reassurance to all stakeholders that its primary objective for ED remains, as a minimum, to reimburse sector debt costs. In the absence of firm guidance, rating agencies and debt investors will simply assume GD&T calibration and RIIO-ED2 structural debt underperformance, leading to rating downgrades and higher debt costs.

FQ3. Do you have any evidence to suggest ED networks should or should not have a debt allowance that has a different calibration to GD&T networks?

As stated in our response to FQ1 and FQ2, we do not believe full indexation is appropriate for RIIO-ED2. Should Ofgem proceed with full indexation and seek to calibrate the ED sector debt costs, we believe it is critical that Ofgem respect that the RIIO-ED2 process is distinct from GD&T and analyse the ED sector on its own merits. We do not believe a balanced and objective assessment approach can presume that GD&T is a valid starting point.

Ofgem has data on ED network debt structures, maturities and expected financing cost for the current price control through the annual RFPR submissions. It will be clearly evident from this dataset that ED financing costs are different to GD&T.

Even if the financing duty to the individual company is disregarded, then the objective for Ofgem must remain to reimburse the sector debt costs as a whole. The GD&T equity return levels have been pushed dangerously low and this does not leave any capacity for networks to absorb under-funding on the debt allowance. GD&T data must not be used by Ofgem to justify under-funding of the ED sector in RIIO-2. This would have severe consequences on financeability and Net Zero delivery.

With 14 DNOs in the sector, Ofgem has sufficient comparator data and does not need to look outside for information on efficient debt costs.

The challenges faced by DNOs in RIIO-ED2 will be different to the other energy sectors and this will be reflected in their Business Plans in due course.

In terms of the calibration approach, we strongly believe that derivatives should be included in the estimation of sector debt costs. To the extent that the efficiency of derivatives cannot be understood simply, networks should be asked to provide additional information.

We look forward to working with Ofgem, through the ENA, to arrive at an appropriately calibrated debt allowance for RIIO-ED2.

FQ4. Do you have any views on our analysis of additional costs of borrowing that may not be captured by an index of bond yields?

We assess that Ofgem's estimate of additional costs of borrowing as presented in 'Table 1: Ofgem estimate of additional costs of borrowing' under-estimate the true costs faced by companies in raising debt finance.

In particular, the cost of carry (including use of RCF) appears to be low due to incorrect assessment of cash positions in the RFPRs. Ofgem also take no account of basis risk from CPI indexation or new issue premium costs. These are real costs that cannot simply be ignored and should be allowed for in order to avoid even further risk being borne by equity.

We fully support the principles outlined in NERA's ENA paper submitted as part of the GD&T Draft Determination response.[1]

We also believe that the financing costs of smaller networks are systemically higher than that of larger networks or Groups. Either as a consequence of accessing capital markets frequently at below benchmark size, or through the additional cash carry costs associated with infrequent issuance.

We include the Frontier Economics paper "*Transaction Cost Premium for Infrequent Debt Issuers*"[2] as evidence in support of this conclusion.

[1] Review of Ofgem's DD Additional Costs of Borrowing, and Deflating Nominal iBoxx, NERA (September 2020)
[2] Annex 5 of this consultation response

FQ5. Do you agree with our proposal to use the longest term OBR forecast for CPI to deflate nominal index yields to a real CPIH allowance and to switch to using OBR CPIH forecasts if these become available?

As detailed in our response to FQ15 we continue disagree with the move away from the use of RPI.

However, in principle we agree that use of the OBR's longest term forecast for CPI would be a reasonable proxy for CPIH in deflating nominal index yields to real. It is stable over time, close to the Bank of England's inflation target and is published bi-annually. We also agree that there should be a switch to CPIH should this forecast become available.

2 Allowed return on equity questions

FQ6. In light of the equity methodology we set out in Draft Determinations for GD&T, do you have a view on how implementation could best be applied to the ED sector?

We generally support the concept of, but not the current execution of, stages one and two (being the Capital Asset Pricing Model ('CAPM') and cross-checks on CAPM)), of the three-stage approach set out by Ofgem in the GD&T Draft Determinations.

We believe components of Ofgem's stage one approach in calculating components of CAPM is flawed regarding calculation of real TMR, equity beta, debt beta and the RFR. Our view on these matters are consistent with the Oxera update paper on the cost of equity submitted by the ENA for Draft Determinations[3] (DDs). The ENA has provided a substantive body of evidence to support the component parts of CAPM which appears to have been routinely disregarded. The latest methodological change regarding gearing born out of the NERL CMA challenge, appears to be the product of mis-calibration of other CAPM components.

As part of the PR19 CMA appeal, Oxera have looked in to this issue and it appears that the assumptions Ofgem are using, particularly regarding the RFR, are the primary cause of this effect. We believe that use of an appropriate RFR (see Annex 1 of ENA submission to CMA review of Ofwat Price Determinations for PR19)[4] alongside reasonable CAPM assumptions can overcome this issue. Oxera highlight five key areas of issue with Ofgem's approach to the Cost of Equity[5]:

- restating the historical total market return (TMR) based on an experimental index for historical CPI, which results in a lower estimated TMR;
- increasing the weight on the geometric average historical return, thereby moving further away from the correct (Cooper) estimator, resulting in a lower TMR;
- moving to spot yields on government bonds, which lowers the estimated risk-free rate (RfR);
- using a debt beta of 0.125 where previously Ofgem used zero, which artificially deflates the notional equity beta;
- reducing the allowed return below the estimate of the cost of equity.

[3] 'The Cost of Equity for RIIO-2 Q3 2020 Update', Oxera (September 2020)
[4] 'Are sovereign yields the risk-free rate for the CAPM', Oxera (May 2020)
[5] 'The Cost of Equity for RIIO-2 Q3 2020 Update', s.5.2, Oxera (September 2020)

We strongly agree with the Oxera findings on the points above and urge Ofgem to re-think its approach in these areas for RIIO ED2.

Regarding stage two (cross-checks) we continue to support the ENA position where evidence provided to date has urged caution on the interpretation of cross-checks Ofgem uses such as MARs, OFTO's and investment management forecasts. As we have previously set out, we believe there is a great deal of subjectivity which gives rise to a range of answers and thereby significantly impact their ability to provide objective support to conclusions drawn from the CAPM.

Regarding MARs, Ofgem's proposals rely heavily on water companies. We are concerned about the use and relevance of water companies in the overall analysis as we do not believe that they are good proxies for Electricity Distribution companies, particularly going forward. That notwithstanding, further evidence of why a premium could exist was presented in an Oxera paper for the ENA as part of the PR19 CMA appeal process.[6] Its conclusion is:

> *"…under a range of plausible scenarios, the current traded premia can be more than explained without any recourse to an assumption that the actual cost of equity is lower than the regulated allowed base equity return. To the extent that conclusions can be drawn, the analysis is consistent with the conclusion that Ofwat has underestimated the cost of equity"*

Given this evidence, we do not believe there is a sufficient basis of understanding of MARs premia such that weight can be given to this as a valid cross-check.

Regarding OFTOs, we maintain this is not a valid cross-check due to the significant risk and structural differences between networks and OFTOs.

For RIIO-ED2, we believe that calibration of cross-checks should be better targeted and more appropriate, and we are happy to work with Ofgem to develop valid alternatives.

We do not support Ofgem's Stage 3 (adjustments for expected outperformance) process. The stage three adjustment (allowed v expected returns) should never be necessary in a well calibrated incentive-based regulatory regime, especially one that is now likely to include RAMs as an overall check. Its inherent current and future uncertainty will result in erosion of investor confidence and increase the risk they face, as well as tempering their view of the stability and predictability of the regulatory framework for future regulatory determinations. It is also likely to have adverse impacts on the incentive regime, distorting key mechanisms that benefit customers like the Totex Incentive Mechanism (TIM).

Notwithstanding our concerns about the stage three process and its validity, it would be incorrect to base any expected RIIO-2 performance on historical information in its entirety, especially given the step change Ofgem are proposing in tightening any opportunity to outperform in RIIO-2. An alternative approach to assess the balance of the whole package, would be to assess the overall incentive package and opportunity of outperformance against the overall penalty and risk of underperformance. This should include all elements of the RIIO-2 package, including financing. Without this assessment it is impossible to justify a lowering of equity return rates against investor expectations and below the fair equity return assessed.

[6] 'What explains the equity market valuations of listed water companies? – A review of Ofwat's use of financial market evidence to support its allowed cost of capital', Oxera (May 2020)

Finally, Ofgem's introduction of an ex-post adjustment for baseline equity returns adds significantly more uncertainty and raises more questions than it answers. Given we do not see the stage three adjustment as necessary, we equally don't see this added complication as necessary. It adds more uncertainty into the mix for investors and distorts incentives, thereby adding to consumers long term costs and likely reducing the future benefits the regime to date has achieved. This proposal is flawed in principle, has been insufficiently developed, and is now being shaped with late evidence. Its inclusion further undermines investor confidence in the regulatory framework and its governance and is detrimental to customers interests.

FQ7. Do you have suggestions on how we could estimate systematic risk for ED2 or any evidence to support a difference between ED and the other RIIO sectors, GD&T?

We firmly believe that Electricity Distribution (ED) faces its own unique set of circumstances and challenges that set it apart from the wider regulated company sector as well as other energy networks.

The Government's Net Zero challenges will affect businesses across the economy to a greater or lesser extent, but for ED it will have a profound effect on how the companies are structured, how they operate, what their deliverables will be and how strategies will be formulated to meet the needs of customers in highly uncertain and fast-changing conditions. ED will be expected to act as a leader and enabler to allow thousands of businesses and millions of customers to meet their own Net Zero ambitions and targets. Given this diversity in our customer base and in the network circumstances, ED faces unique infrastructure challenges in meeting what will likely be an enormous variety of low-carbon challenges on the distribution network. It is clear that the technological and delivery challenges in delivering and spear-heading the move to Net Zero pose a far greater challenge to Electricity Distribution companies than those faced by companies in the water, or even other energy sectors.

Substantial investment in distribution networks will be required to meet Net Zero which given the relatively higher systematic risk compared to other sectors as outlined above, will require adjusting for in determining a fair equity beta and return on equity.

We are happy to work with Ofgem to develop more credible evidence for ED systematic risk.

3 Financeability questions

FQ8. Do you agree with our proposal to align the RIIO-ED2 financeability approach with the approach we have taken for GD&T?

We do not agree with aligning the RIIO-ED2 financeability approach with the approach Ofgem have taken for GD&T.

As a fundamental principle, we consider that Ofgem's legislative duty is to ensure the financeability of individual networks and not the notional company or the sector average. As such, it follows that the regulator needs to have due regard to individual company circumstances to successfully discharge this duty.

We equally accept that this cannot represent carte-blanche for networks and there should be a requirement to identify any inefficient costs to avoid customers funding these. However, this financing duty is established to ensure that the long-term interests of consumers in each licence area are met.

It also cannot be appropriate to set equity returns independently and then expect equity to simply subsidise under-funding associated with efficiently raised debt with no implications.

FQ9. Are there any reasons why this approach should differ for RIIO-ED2?

As detailed in our response to FQ8, we are in strong disagreement with the financeability approach adopted by Ofgem for GD&T.

We believe that DNOs, and the five-year period to 2028, are critical to the successful delivery of Net Zero by 2050, and in the case of ENWL and Greater Manchester, by the earlier target date of 2038.

It is essential that the financeability of all DNOs is secured, together with a well balanced incentive package that is aligned to the long-term interests of consumers and stakeholders.

We look forward to working with Ofgem on developing the financeability assessment for RIIO-ED2.

FQ10. Do you have a view, supported by evidence, regarding the appropriateness of different measures to address any financeability constraints?

The results of the financeability assessment should not be used to justify the choice of notional gearing.

Notional company gearing is a determining factor in the long-term financing structure of networks. Regulatory consistency is critically important here and any decision to move from previous price controls needs to be carefully considered and well-justified.

The actual gearing levels of networks is an important consideration. If it can be demonstrated that these are consistently below the current notional gearing level and any change can also be justified with regard to customers interests then a well-signalled change, with transitionary arrangements may be appropriate.

The financeability assessment at the existing notional gearing level should be sense-checked as to whether the equity return, and debt allowance proposals are viable. The notional gearing level should not be used as a lever to make the assessment workable.

FQ11. Do you have any views on the proposed scenarios to be run for stress testing?

Ofgem has stated: *"…we would suggest that scenarios are designed to cover realistic high and low cases, rather than extreme scenarios."*[7]

[7] RIIO-2 Sector Specific Methodology Decision – Finance, paragraph 4.72, Ofgem (May 2019)

Given the widespread economic impact of COVID-19 and its future uncertainty on demand, we believe the Ofgem scenarios (particularly the macro scenarios) have insufficient ranges to capture potential downside scenarios.

We also believe that the current severe tightening in the GD&T price control introducing significantly higher probabilities of under-performance, penalties and restricted incentives, alongside RAMs and treatment of financing costs, means that the downside RoRE scenario is insufficient for stress testing.

4 Financial resilience questions

FQ12. Do you agree with our proposal to place additional requirements on licensees in RIIO-ED2 to provide Ofgem with a) published ratings reports, and b) a financial resilience report if their issuer credit rating falls below specified levels?

We support the principle of effective regulatory oversight to ensure companies remain financially resilient. However, the timing of this request is curious in so much as this is aligned to the severe tightening of the "notional" regulatory regime to such a point where actual well-managed companies may now suffer, through no fault of their own, financial distress as a direct consequence of the new framework; as we have mentioned in FQ9, Ofgem has a financing duty to each of the actual companies.

5 Corporation tax questions

FQ13. Do you agree with our proposal to align the RIIO-ED2 tax approach with RIIO GD&T including; to pursue Option A; the approach to additional protections; the approach to capital allowances; and not to pursue the Fair Tax Mark certification as a requirement for RIIO-2?

We agree with Ofgem's approach to align tax methodologies with GD&T for RIIO-ED2. Out of the options put forward for consideration, we would agree that Option A is the most suitable.

We agree that there should be a level of materiality in place. The current RIIO-ED1 deadband affects allowances, rather than being a tool for an assessment of materiality for a tax reconciliation. Therefore, at this stage, we would need to undertake further analysis to determine what would be an appropriate materiality threshold,

For the Tax Trigger and Tax Clawback mechanisms, we are mindful of certain instances where the clawback mechanism might have the following unintended consequences, for example:

- The impact of Ofgem changing notional gearing
- Where interest costs are disallowed for tax
- If there is a timing difference, i.e. where the associated tax benefit was not received for the period in question.

We believe these consequences should be taken into consideration when ascertaining whether the tax clawback should be applied.

Regarding the Tax Review, we have concerns about the structure and balance of the proposed wording, especially when considered alongside the drafting for other such re-opener mechanisms.

This has been underlined by Ofgem's response where they have stated that they do not necessarily expect this tax review mechanism to result in positive adjustments to the tax allowance (albeit they have stated that the drafting will remain silent on this). We believe there should be safeguards put in place that are in line with other re-opener mechanisms. We would like to see further guidance and clarification on the process that stakeholders must follow to notify Ofgem of a concern.

For capital allowances, although we agree in principle to making allocation and allowance rates Variable Values so that they are more aligned to actual results, we would like to see further guidance on how this will work in practice. In particular, for the change in allocation percentages, could the allocations be different for individual years and would the onus be on the company to calculate and revise the allocations on an annual basis? Would it be a requirement for companies to perform this calculation annually, even if they are not expecting the outcome to be materially different to the previous allocation? What methodology would be put in place to ensure a consistent approach is taken across the network operators? Furthermore, we would like to ensure that the simplification does not result in unintended consequences which have a detrimental effect on the calculation of the tax allowance.

Having just gained the Fair Tax Mark accreditation, we see no reason why this shouldn't be a requirement to further advance the credibility of the UK regulatory regime.

FQ14. Are there any reasons why this approach should differ for RIIO-ED2?

We are comfortable with the principles of the overall approach. Please refer to FQ13 for specific concerns.

6 Indexation of the RAV and allowed return questions

FQ15. Do you agree with our proposal to implement CPIH inflation?

The problems inherent in the Retail Price Index (RPI) are well understood. However, steps are underway to reform the index, with changes potentially introduced from 2025, two years into RIIO-ED2.

Any move away from RPI is problematic for networks. Adopting RPI-linked financing, either directly as index linked bonds or through the use of derivatives, has helped manage inflation risk in networks for many years. Much of this RPI-linked financing is structural and long-term, it cannot be restructured easily without cost. If CPI or CPIH is adopted, then this could not have been foreseen by networks and debt allowances should be adjusted to include the cost of removing any resulting basis risk.

While there was a strong rationale to implement an alternate measure of inflation in RIIO-2, we believe this rationale has diminished following the reform proposals. Noting the negative impact associated with the change, we do not believe the 'ends' justify the 'means' and we request that Ofgem reconsiders this strategy for RIIO-ED2.

FQ16. Are there any reasons why this approach should differ for RIIO-ED2?

Please refer to FQ15.

7 Regulatory depreciation questions

FQ17. Do you have any specific views or evidence relating to useful economic lives of ED 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-ED2, 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.

FQ18. During RIIO-ED1, the assumed asset life is being increased. Do you consider another change is required in RIIO-ED2 to reflect the expected economic asset life? If so, do you have supporting evidence and proposals, at this stage?

Prediction of an aggregate useful economic life across the entire asset base will become increasingly uncertain as technological advances accelerate and the move to Net Zero picks up pace. It may well be that certain existing assets could become obsolete in a shorter timeframe and that new types of network assets have significantly different profiles to existing assets. As such, we need to monitor this alongside the business plan to ensure the correct intergenerational balance is maintained. As noted in FQ17 above, we also see this, subject to intergenerational fairness, as a lever to manage future financeability constraints.

8 Capitalisation rate questions

FQ19. Do stakeholders support licensee specific rates for the ED sector?

Yes. As a starting reference point, we would agree with estimating capitalisation rates from accounting distinctions. However, if deviations can be justified and agreed by networks and Ofgem, we also support moderate deviations from this natural rate if in the wider interests of consumers. However, excessive deviation will become an issue if the ratings agencies view it as an artificial construct.

FQ20. For one or more aggregations of totex, should we update rates ex-post to reflect reported outturn proportions for capex and opex?

There are a number of approximations in the assessment of capitalisation rates and it will never be perfectly accurate, neither does it need to be. The benefits of predictability and certainty over capitalisation rates are significant and, in this area, they should not be disregarded in the pursuit of greater alignment with historic accounting distinctions.

The scope for a material restatement of RAV following an ex-post adjustment is a real concern and this could inadvertently lead to breach of financial covenants and financial distress.

For these reasons, we do not support the use of ex-post adjustments for capitalisation rates.

To the extent that additional totex awarded through uncertainty mechanisms has a materially different natural capitalisation rate, the specific capitalisation rate for this spend should be agreed ex-ante as part of the award, if the individual or cumulative amount is significant.

9 Directly remunerated services questions

FQ21. Are there any reasons why the RIIO-ED2 approach to directly remunerated services should differ from RIIO-ED1?

We are comfortable that RIIO-ED2 approach aligns to RIIO-ED1 however, as we explain in our response to Q24 of the Overview document, we have recently identified some limitations when it comes to whole system approaches.

There are recent examples of DNOs meeting Transmission or System Operator needs which have been arranged on a commercial basis, such as the Accelerated Loss of Mains project. It was agreed with Ofgem that DRS9 would be used to manage costs associated with the programme. However, as this is a miscellaneous category which could contain a range of activities that don’t naturally fit within one of the other DRS categories, we suggest the categories are reviewed, with the potential of creating a tenth DRS category which is specifically to accommodate commercial transactions across networks. The goal would be to ensure there are no barriers to using DRS as a route where projects do not merit Co-ordinated Adjustment Mechanism (CAM) applications. This will further support the aim of transparency and ensure activities are not mixed in with other reported costs.

10 Disposal of assets questions

FQ22. Do you support our proposal to continue the RIIO-ED1 approach to disposal of assets for RIIO-ED2?

We agree with this approach.

11 Dividend policy questions

FQ23. Do you agree that additional reporting on executive pay/remuneration and dividend policies will help to improve the legitimacy and transparency of a company's performance under the price control?

We do not agree that additional reporting on executive pay/remuneration and dividend policies will help to improve the legitimacy and transparency of a company's performance under the price control. We believe that current reporting requirements, under various statutory provisions, provide a level of disclosure that is both sufficient and consistent. We believe that there will be insufficient consistency and context available in the public domain (due to commercial sensitivity, data protection, etc.) to enable fair comparison and assessment of such disclosure. It should be noted that disclosure of executive pay creates a barrier to promotion and recruitment/retention of talent which the industry needs to be able to attract. Regarding reporting of dividend policies, having set an expected rate of return and an incentive/penalty regime around this, coupled with a gearing limitation, we fail to see the purpose of publishing dividend policies. If the purpose is to restrict dividends, then this represents a restriction on equity earnings and needs to be factored into the overall equity return allowance.

12 Return adjustment mechanism questions

FQ24. Do you agree with our proposal to introduce a symmetrical RAMs mechanism?

As a principle, we do not support the inclusion of RAMs within the RIIO-2 framework as these are not required if Ofgem sets an appropriate price control at the outset. RAMs distort the working of incentives, whose property has been one of the cornerstones of the success for consumers of Ofgem's regulatory regime.

The justification for the introduction of the RAMs appears to be two-fold. Firstly, as a failsafe to cap any perceived excess returns generated by strongly performing networks and secondly, to protect the cash flows and financeability of underperforming networks.

While a symmetrical RAMs mechanism is attractive from a simplicity perspective, it does not accurately reflect the weight of consequences at each boundary. The shape of the RAM ought to be informed by the package in the round of the regulatory mechanisms, and what scope Ofgem wants to allow for company performance to drive the level of returns achieved. The design of the RAM might need to be company specific, and the elements included and not included in how the RAM's work might impact how it is designed symmetrically or otherwise.

We believe that Ofgem needs to give greater consideration to setting an appropriate floor level for the RAM, ensuring that it is triggered at a level, and in a manner, that limits distress of the affected networks in a way that is proportional to those networks impacted at the RAM ceiling. This will be an important factor both in assessing downside financeability and in discussions with ratings agencies.

FQ25. Do you agree with our proposal to introduce a single RAM threshold level of 300 basis points either side of the baseline allowed return on equity?

A single threshold level benefits simplicity, but noting our response to FQ18, we do not necessarily support a symmetrical threshold either side of the baseline allowed return on equity.

Any RAM should be structured so that does not disincentivise networks from continuing to strive for innovation and further efficiency. The threshold level should be set in this context.

We note that the Output Delivery Incentive (ODI) package outlined in this consultation would appear to provide outperformance potential above the 300bps threshold. This is before any outperformance generated through operating and capital efficiencies.

In our view, setting a single RAM threshold cap at 300bps is too restrictive and would undermine the legitimate strength of incentives when these are considered as a collective package, potentially curbing a company's ambition to drive outcomes for consumers. Ofgem needs to provide confidence to stakeholders if companies are successful in delivering what customers value across several incentives.

Should the RAM be introduced, we propose a two-stage approach to the thresholds, resulting in a banding. On a post-financing and tax basis, for returns 300bps-500bps above the required equity return, companies should demonstrate that customers are receiving the benefits intended by the incentives and also contribute funding worth 1 in every 10 bps over this 300 bps threshold up to 500 bps to a vulnerable customer support fund for their region.

For returns of 500bps plus, the full RAMs mechanism would be introduced with Ofgem then confident that legitimacy will be secured.

FQ26. Do you have any other comments on our proposals for RAMs in RIIO-ED2?

The current RAMs proposal is structured around equity returns, with adjustments triggered as those returns deviate materially from the baseline. If the core argument in support of RAMs is to prevent 'excessive' outperformance, then we do not see how it can be justified to base the RAMs assessment on an incomplete view of equity returns, which excludes financing and tax performance.

Excluding some elements of outperformance in this way does nothing to support the legitimacy of returns to shareholders.

If the secondary argument for RAMs is to support the credit metrics of underperforming companies, we also do not see how this is achieved if financing underperformance is excluded. It is of no comfort to investors that a licensee had an underpin on penalties, if it has just gone bust on financial underperformance.

This serves to identify the consequence of the policy to set the debt allowance based upon sector average, rather than on a needs basis. It is this policy that will create permanent winners and losers.

We also believe the RAMs proposal is open to undesirable outcomes. It is not unfeasible for a network that is poorly performing operationally to be granted additional effective subsidisation from customers, while also being overfunded in respect of its debt costs. This cannot be in the interests of customers.

In addition, if a licensee is certain to outperform on debt costs, it may not have the same incentive or management drive to outperform on ODIs, which would be to the detriment of its customers. This is in contrast to ENWL, where we are delivering operational outperformance of 4.3 percent, benefitting customers directly through improved reliability and cost sharing, but then overall losing around half of this on financing and tax underperformance.

It is essential for the technical integrity of the mechanism that RAMs include financing and tax performance, i.e. include all net returns to equity and not some. If the debt allowance was instead structured to cover efficiently incurred embedded debt costs on an individual company basis, then financing performance would then relate only to that which was generated in the current price control, and not on issuances in previous periods when your issuance timing happened to be lucky in hindsight.

The price control mechanism already includes various existing measures to control the levels of out and under performance in specific areas. The rationale to include another measure in respect of certain specific items only is limited, while it is misleading to present it as a solution to perceived excess returns while it remains an incomplete view of excess returns itself (i.e. excludes tax and financing as currently proposed).

In the context of a price control including RAMs, we also do not see the justification for also including an adjustment to equity returns for allowed versus expected returns. Ofgem is introducing layers of complexity into the price control in areas such as uncertainty mechanisms, while refusing to consider alternate approaches elsewhere on the grounds of regulatory consistency and simplicity.

Should Ofgem continue with both RAMs and an adjustment to equity returns, the baseline equity return must be set at the expected return level and the RAM should be set around the baseline equity return pre-any adjustment. The logic of this is clear if one considers a situation with a larger allowed versus expected adjustment was proposed – say 200bps. In this scenario, Ofgem would be setting allowed returns 200bps below the return level required by investors on the basis that they will outperform. However, if the current RAM proposal was also adopted with baseline returns set at the allowed return level, returns would then start to be adjusted when they were only 100bps higher than the expected level (or indeed 500bps below). This is clearly an undesirable outcome.

Sector Specific Methodology Consultation response

Annex 5: Frontier Economics Report for ENWL

Transaction cost premium for infrequent debt issuers

September 2020

TRANSACTION COST PREMIUM FOR INFREQUENT DEBT ISSUERS

A report prepared for ENWL

29 September 2020

CONTENTS

EXECUTIVE SUMMARY

ENWL has commissioned Frontier Economics to independently assess the potential transaction cost differential on debt financing borne by a small DNO such as ENWL compared with its larger counterparts, within the context of setting the cost of debt allowance for ED2.

Context

There are 14 GB electricity distribution licences currently owned by 6 DNO groups. Of these, ENWL is the only DNO group that operates a single licence. At the time of our analysis, ENWL is the smallest DNO group by value of total RAV of approximately £1.8 billion (as of March 2019).

This context is important for this analysis. Although debt can be issued at individual licensee level, in principle DNOs have the option to issue bonds at the group level if they so choose. As a result, larger groups could benefit from economies of scale in market-sized corporate bond issuance that a single licensee, such as ENWL, is not able to achieve.

In its RIIO-2 framework consultation[1] and methodology decision[2], Ofgem has not proposed to make an explicit allowance on company specific characteristics in relation to the cost of debt, including transaction costs. Specifically, in its RIIO-GD2/T2 Draft Determinations, Ofgem considered a proposal from SGN for a premium to cover additional costs that stem from being an infrequent issuer due to small size.[3] While Ofgem rejected SGN's representation which sought an additional allowance for having to issue at a rate higher than the market benchmark, Ofgem has indicated that it would be open to consider individual adjustments to the cost of debt allowance for companies should evidence be provided to demonstrate that this is justified.

Our approach

Origins of higher transaction costs for smaller companies

When issuing debt, companies incur a range of transaction costs in addition to the interest costs owed to debt holders. Transaction costs relate to:

- **illiquidity costs –** costs driven by the way bonds are bought and sold in the financial market due to bid-ask spreads (dependent on the size of the bonds), which can translate into the primary market of issuance;

[1] Ofgem, RIIO-2 Framework Consultation, March 2018, https://www.ofgem.gov.uk/system/files/docs/2018/03/riio2_march_consultation_document_final_v1.pdf

[2] Ofgem, RIIO-2 Framework Decision, July 2018, https://www.ofgem.gov.uk/system/files/docs/2018/07/riio-2_july_decision_document_final_300718.pdf

[3] Ofgem, RIIO GD2/T2 Draft Determinations, Finance Annex, page 19.

- **issuance costs** – such as fees to financial intermediaries, legal advisors and credit rating agencies, which are partly fixed and partly variable in relation to the size of the bonds; and
- **costs of carrying excess cash –** the difference between the interest cost paid and the interest earned on the cash balance in short-term cash deposits[4].

Some of these costs are fixed. Hence by issuing a larger sum, these fixed costs may be spread over a larger total quantum and become proportionately smaller in relation to each pound of debt raised. Others, such as cost of carry, increase with the quantum issued, i.e. by issuing a larger sum the company will be left with extra cash in the short term, on which it will earn a minimal return on deposit while being obligated to pay interest cost.

Types of financing profile

Companies need to develop strategies to manage these costs efficiently. And in developing these strategies, it is clear that a larger company that needs to issue a larger amount of debt in any given period will have natural advantages.

- A large company with a large volume of debt issuance to perform is able to issue larger tranches of debt, thereby reducing illiquidity premium on the bonds (which tend to be high on the small-sized bonds);
- A large company can also proportionally reduce the issuance costs compared to a smaller company, due to the size of the issuances;
- As large companies typically have an adequate size of revolving credit facilities (these are often in proportion to the size of the RAV), refinancing often requires a lower issuance in advance of existing bonds expiring compared with smaller companies. Large companies are therefore better placed than smaller companies to manage costs of carry.

For a smaller company, there are essentially two types of financing profile that could be followed to manage their debt costs.

- The company can choose to issue "frequently" – issuing relatively small tranches of debt annually according to its annual financing needs; or
- The company can choose to issue "infrequently" – issuing relatively larger tranches of debt less frequently.

The "frequent" issuance profile will lead to relatively small sums being issued and will hence increase proportionately the first two costs. However, it will reduce the cost of carry. The "infrequent" issuance strategy does the opposite.

Although this paper does not seek to identify the "optimal" financing profile for a company, as it does not consider all the relevant factors including intangible costs involved in the financing decisions, the relevant regulatory question we seek to answer is how large is the intrinsic debt issuance transaction cost disadvantage faced by a small company relative to larger ones, under either of these two financing profile?

[4] The allowed return does not cover the interest cost on excess cash because the excess cash does not contribute to existing investment in assets that are registered in the RAV – the allowed return is set by the allowed rate of return multiplied by the RAV.

Our approach to modelling

We have developed a simple spreadsheet model that converts each of the three additional debt costs identified above into an equivalent amount of additional debt interest cost. We populate this model with information provided by ENWL, on the actual size of each of these three transaction costs. We then compare these costs for a notional small company (with the size of ENWL) with the costs for a notional large company, to quantify the size of the transaction cost differential.

It is worth noting that the focus of our analysis is on the differential between the notional smaller company and the larger company, rather than the absolute level of transaction costs, as we have not included certain elements of the transaction costs that are shared across companies regardless of their size (such as cost of carrying for daily cash requirements or working capital facilities).

Key findings

Figure 1 summarises the results of our transaction costs analysis.

Figure 1 Additional transaction costs on the cost of debt for small and large companies

Company size	Small		Large
Financing profile	***Frequent***	***Infrequent***	***Frequent***
Key assumptions			
RAV [£]	1800m		7000m
Debt issuance [£]	108m	324m	420m
Issuing frequency	1y	3y	1y
Illiquidity costs	✓ 15bps	✓ 6bps	✓ 6bps
Issuance costs	✓ 15-18bps	✓ 7-8bps	✓ 6-7bps
Costs of CC	✗ 1bps	✓ 21-23bps	✗ 1bps
Total transaction costs	**31-34bps**	**35-37bps**	**13-14bps**

Source: Frontier Analysis

Note: Each of the costs here are in annual interest rate terms to make them comparable to a company's allowed cost of debt and any potential small company premium.

We find that regardless of financial profile adopted, a smaller company like ENWL would incur higher transaction costs on debt financing than a large company. This additional cost is structural and cannot be fully mitigated.

More specifically, we find a smaller company of a size similar to that of ENWL would incur additional transaction costs of 18-20 bps on debt, with this cost minimised (according to our modelling) using the most cost effective financing profile. It is worth noting that this analysis does not include all relevant transaction costs, for example:

- It does not consider the costs of cash carry in relation to day to day liquidity management and/or revolving working capital facilities.

- it does not consider the management resource used up in the issuance of debt if this is done more frequently than necessary (as with other issuance costs, management costs will be fixed in nature and hence provide another source of scale economies in issuance).

Furthermore, we have chosen a financing profile that is the least costly to compare with larger companies' transaction costs. In reality, it is likely to be unfeasible for an infrequent issuer to suddenly switch to becoming a frequent issuer (e.g. the refinancing of an existing large bond cannot easily be done through a series of frequent but consecutive smaller issuances because there will be a shortage of cash to repay the maturing debt). We have not taken this path dependency issue into account.

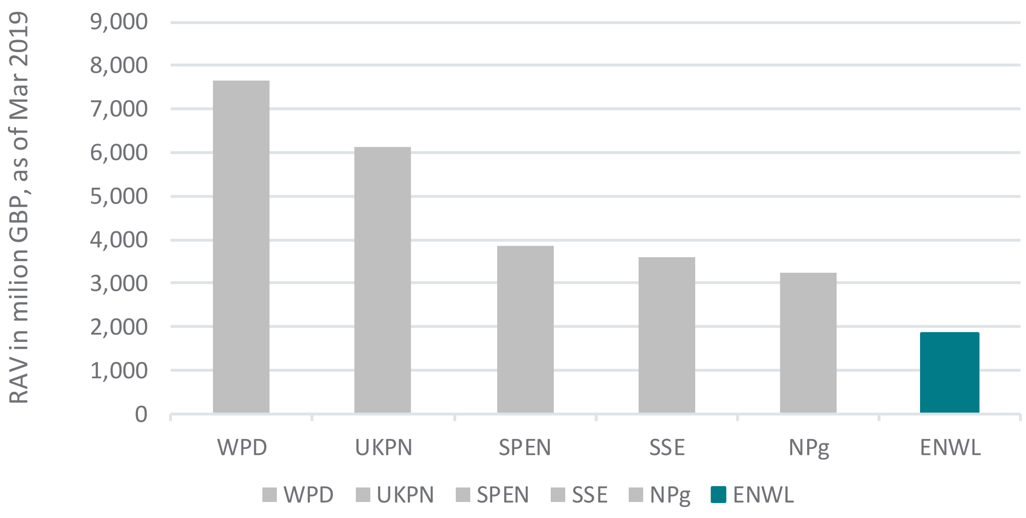
Overall, the factors above would suggest that the differential in transaction cost we have identified in this analysis may be a conservative estimate of the actual differential in reality. In conclusion, we consider that there is reasonable justification for the regulator to make an explicit additional allowance over the sector debt allowance in the range of 18-20 bps for smaller companies, to contribute to the premium they face on smaller and/or more infrequent debt issuances.

1 INTRODUCTION

ENWL has commissioned Frontier Economics to independently assess the potential transaction cost differential on debt financing borne by a small DNO such as ENWL compared to its larger counterparts, within the context of setting the cost of debt allowance for ED2.

There are 14 electricity distribution licences under Ofgem's ED1 price control, currently owned by 6 DNO companies. At the time of our analysis, ENWL is the only single-licenced DNO, and is the smallest DNO group by value of total RAV of approximately £1.8 billion (as of March 2019), as shown in Figure 2 below.[5] This context is important for this analysis, as although debt can be issued at individual licensee level, DNOs have the option to issue bonds at the group level if they so choose. Based on this, larger groups could benefit from economies of scale in market-sized corporate bond issuance that a single licensee, such as ENWL, is not able to achieve.

Figure 2 ENWL is the smallest Electricity DNO in the UK by RAV



Source: Ofgem ED1 financial model (November 2020)

Note: Prices converted to March 2019 prices using RPI data

In its RIIO-2 framework consultation[6] and methodology decision[7], Ofgem has not proposed to make an explicit allowance on company specific characteristics in relation to the cost of debt. However, Ofgem has indicated that it would be open to consider individual adjustments to the cost of debt allowance for companies such as Electricity North West Limited (ENWL) and Wales & West Utilities (WWU), if robust and convincing evidence can be presented.[8]

5 RAV figures taken from Ofgem financial model 2020, based on figures for closing RAV as of 31 March 2019. These are the latest official RAV figures for the ED sector at the time of writing of this report.

6 Ofgem, RIIO-2 Framework Consultation, March 2018, https://www.ofgem.gov.uk/system/files/docs/2018/03/riio2_march_consultation_document_final_v1.pdf

7 Ofgem, RIIO-2 Framework Decision, July 2018, https://www.ofgem.gov.uk/system/files/docs/2018/07/riio-2_july_decision_document_final_300718.pdf

8 Ofgem, RIIO 2 Framework Decision, July 2018 – paragraph 6.28

In its RIIO-GD2/T2 Draft Determinations, Ofgem considered a proposal from SGN regarding a premium resulting from being an infrequent issuer due to its small size.[9] SGN suggested that due to its infrequent issuance of bonds, it has a larger risk of the capital market being unfavourable when it needs to issue and therefore a risk premium needs to be allowed to compensate. Ofgem rejected SGN's representation, particularly in relation to the quantification of such a premium using the swaption instrument. Ofgem has also rejected the idea of an infrequent issuer potentially having to issue at a rate higher than the market benchmark.

For this report we have not examined the issues raised by SGN in its submission. Instead we focus on identifying and quantifying an arguably more pertinent reason for a cost premium for a smaller company which may need to issue more infrequently. This comes in the form of a demonstrably higher level of transaction cost associated with debt issuance faced by smaller companies.

In the RIIO GD2/T2 Draft Determinations, Ofgem proposes to switch to the iBoxx Utilities from the iBoxx A and BBB indices used in RIIO1, with estimated transaction cost allowance separately. Our study is in line with the methodology Ofgem has employed to estimate the transaction costs, and we find similar results to those from Ofgem, although unlike Ofgem's analysis which sought to estimate the total transaction cost for DNOs our analysis focuses on the cost differential between smaller and larger issuers.

Our analysis shows that there is a material difference for a smaller company that may need to either issue debt less frequently or issue smaller sums more frequently.

Ofgem has also suggested that smaller companies could circumvent the problem by simply issuing more frequently but at a sub-benchmark size (e.g. lower than £250 million for bonds). In our study we assess the cost associated with more frequent issuance for a smaller company, and quantify the conditions under which more frequent issuance would be preferred. However, even in these situations, there remains a differential in transaction cost compared to a frequent issuer but at larger issuance sizes.

This report:

- explains the differentials in transaction costs between smaller and larger companies, both for infrequent issuance and more frequent issuance;
- assesses the levels of these differentials;
- and proposes a range for the transaction cost differential on debt for a relatively smaller company such as ENWL.

The rest of this report is structured as follows:

- Section 2 explores the financing profile options for smaller and larger companies;
- Section 3 assesses illiquidity costs as a source of company specific transaction cost on debt;
- Section 4 estimates issuance costs as a component of the cost of debt;

[9] Ofgem, RIIO GD2/T2 Draft Determinations, Finance Annex, page 19.

- Section 5 estimates costs of carrying excess cash as a component of the cost of debt; and
- Section 6 combines all the relevant factors above and estimates a range for the cost differential that applies to the transaction cost on debt for a company of the size of ENWL.

2 OUR OVERALL APPROACH

2.1 Sources of transaction costs

It is well established in finance theory, as well as within regulatory precedent, that small company size can lead to a material premium on the cost of debt due to the existence of scale economies in transaction costs on debt financing. Our study aims to establish if the excess transaction cost on debt for small companies can be considered sufficiently material to warrant an additional regulatory allowance.

When issuing debt, firms incur transaction costs in addition to interest costs. Transaction costs can relate to:

- **illiquidity costs** – costs driven by the way bonds are bought and sold in the financial market due to bid-ask spreads (dependent on the size of the bonds), which can translate into the primary market of issuance;
- **issuance costs** – such as fees to financial intermediaries, legal advisors and credit rating agencies, which are partly fixed and partly variable in relation to the size of the bonds; and
- **costs of carrying excess cash –** the difference between the interest cost paid and the interest earned on the cash balance in short-term cash deposits[10].

Some of these costs are fixed. Hence by issuing a larger sum, these fixed costs may be spread over a larger total quantum and become proportionately smaller in relation to each pound of debt raised. Others vary in size of the bonds. Illiquidity premium for example decreases with the size of the bond, whereas cost of carry increases with the quantum issued.

Figure 3 provides an overview of these transaction costs.

[10] The allowed return does not cover the interest cost on excess cash because the excess cash does not contribute to existing investment in assets that are registered in the RAV – the allowed return is set by the allowed rate of return multiplied by the RAV.

Figure 3 Three different issues considered relating to smaller company debt costs

1 Illiquidity Costs

- Bonds smaller than £250m are likely to be traded less frequently.
- Buyers and sellers expect to see a liquidity premium in market yields to compensate for this lower frequency of trades…
- …this would be a cost to the firm and it would be priced in to the coupon rate

2 Issuance costs

- In order to issue bonds, firms incur issuance costs in addition to interest costs. A significant part of these costs is fixed (e.g. legal/credit rating fees, commissions)
- Therefore, issuance costs as a % of principal are higher for small bonds compared to larger bonds.

3 Cash carry costs

- To refinance bonds at date of maturity, firms might be required to seek new finance 12-18 months ahead of bond refinancing in order to ensure sufficient liquidity.
- Thus, they would carry excess cash on which they pay interest at the bond rate, but receive only small cash interests.
- However, if a firm is able to secure an RCF that satisfies the liquidity requirements it can re-finance closer to the date of maturity of existing bonds and it therefore has less carry cost.

Source: Frontier Economics

We note that illiquidity cost may exhibit itself as a premium on the yield of the bond in question. However, for the purpose of this analysis, we categorise it as a transaction cost as it is unlikely to have been included in the benchmarked efficient debt costs informed by large benchmark bonds.

2.2 Determining comparators

A smaller company can be on either a "frequent" or "infrequent" financing profile. In other words, it can serve its financing needs annually or it can issue larger sums of debt less frequently;

- If a smaller company issues bonds annually (e.g. around £100m), it decreases the amount of excess cash the company needs to hold, but creates higher illiquidity and issuance costs (we explain in more detail below why this is the case).
- Conversely, a smaller company can opt to issue a larger bond (more than £250m) by issuing debt less frequently. In this case additional transaction costs would arise mainly from excess cash holdings.

In comparison, the annual financing needs of a large company are large enough such that issuance costs and illiquidity costs are relatively small due to the size of the bonds required (generally exceeding £250m). Also, a large company could minimise transaction costs by adopting a "frequent" financing profile and issuing debt annually. Therefore, larger companies have natural cost advantages when deciding which financing profile to follow when compared to a smaller company.[11]

Our analysis follows two steps to estimate the transaction cost differential between the smaller and the larger company:

[11] We note that this does not preclude a large company from nevertheless choosing a more infrequent financing profile if it is considers it advantageous to do so, due to other considerations such as capital market conditions.

- First, we compare the transaction costs of a notional small company between its "frequent" and "infrequent" financing profiles;
- Second, we compare the *lower* transaction cost scenario of the small company with the transaction cost of a notional large company issuing debt "frequently".

The resulting differential then provides a conservative estimate of the potential size of a transaction cost differential between smaller and larger companies. It is conservative because:

- it does not consider the management resource used up in the issuance of debt if this is done more frequently than necessary; and
- it does not consider the fact that once a certain profile is chosen, it is costly for a small company to switch to the other profile (either from infrequent to frequent or vice versa).

We note that this paper does not seek to identify the "optimal" financing profile for a company as it does not consider all the relevant factors including intangible costs involved in the financing decisions.

2.3 Assumptions on notional debt issuance volumes

Our analysis considers stylised financing profiles for the notional companies and derives notional bond sizes for each scenario. These are based on the following assumptions:

- The comparison considers a notional small and large company with a regulated asset value of £1,800m and £7,000m, respectively. The smaller company is similar to ENWL's size at the time of this analysis, and the large company is similar to the size at which the transaction costs in our model can be considered minimised allowing for a frequent financing profile. Some regulated energy network companies are currently at or above this size;
- Both notional companies are assumed to have a RAV gearing level of 60%;
- Bonds are issued at a 10 year tenor. This assumption is based on the majority of bonds usually being issued either at 7-12 year tenors or at 20+ year tenors. We do not consider 20+ year tenors, as regulated network companies are incentivised to issue bonds that match regulators' cost of debt indexation mechanisms which tend to focus on maturities less than 20 years.
- Bonds are issued at a coupon rate of 2.51% - 4.18% according to iBoxx indices from the past five years[12];
- A company with an "infrequent" financing profile issues bonds every three years whereas a company with a "frequent" profile issues bonds every year;
- Bonds are issued for the purpose of refinancing maturing existing bonds rather than financing new investments; and
- The cost of carry incurred for the need to finance new assets is assumed to be similar across all companies and not included in our calculations.

[12] The upper and lower bounds are taken from the P90 and P10 of the iBoxx yield within the past five years, in order to depict a reasonably unbiased picture of the debt market in the medium term. We recognise that the latest yield is lower than our P10 scenario, due to the ongoing fall in the interest rates.

Figure 4 summarises the characteristics of the notional companies in our comparison and their respective financing profiles that we analyse.

Figure 4 Assumed bond size by financing profile and company size

Company size	**Small**		**Large**
Financing profile	***Frequent***	***Infrequent***	***Frequent***
RAV [£]	1800m		7000m
Gearing	60%		
Coupon rate	2.51% - 4.18%		
Bond Maturity	10y	10y	10y
Issuing frequency	1y	3y	1y
Debt issuance [£] *(RAV * gearing / maturity * frequency)*	**108m**	**324m**	**420m**

Source: Frontier Economics

In our stylised model, the large company with a RAV of £7,000m and a gearing level of 60%, would need to raise finance each year with a bond of £420m. A small company with a RAV of £1,800m would either need to raise a bond of £108m each year or raise a bond of £324m every three years.

In the following sections, we will look at the various transaction costs associated with these different scenarios.

3 ILLIQUIDITY COST

This section assesses illiquidity cost across bonds of different sizes. In particular, we use the relative bid-ask spread measure of liquidity to see if bonds with smaller issuance sizes are less liquidly traded than bonds with larger issuance sizes.

If smaller bonds are less liquid than larger bonds, then companies that issue smaller bonds will face additional costs. Investors in companies that issue smaller bonds need to be compensated for lower liquidity, which is likely to be priced into the coupon rate paid by firms. We note that even though this cost may manifest itself as a higher cost of debt, we consider it as a form of additional transaction cost in our analysis because it is unlikely to be have been accounted for in the estimation of "efficient levels of cost of debt" through benchmarking analysis.

3.1 Our approach

In financial markets, illiquidity refers to the fact that when an investor looks to buy or sell an asset, he/she may not be able to find a willing counter-party as easily due to the lack of interest from other market participants to trade this asset. It may then be necessary for the investor to sell at a lower price (higher yield in the case of bonds). A rational investor will need to be compensated for bearing this illiquidity risk. Illiquidity costs are therefore transaction costs that the issuer of an illiquid bond would incur.

One of the well-recognised indicators of liquidity is the so-called relative bid-ask spread. This is the difference between the bid-price (buy price) and the ask-price (sell price) of a bond, relative to the mid-price of the bond. Liquid assets typically command a narrower bid-ask spread than illiquid assets, due to the fact that dealers are more confident in their ability to unwind positions on a liquid asset and can therefore afford to charge a smaller margin for facilitating the trade.

In reality, larger bonds will be more liquid than smaller bonds and will have a lower relative bid-ask spread. One reason for this could be that bonds need to be relatively large to be included in a number of fixed income and bond market indices. For example, only bonds above £250m would be considered in the iBoxx indices[13]. The inclusion in such an index attracts a wider pool of investors making those bonds more likely to attract liquidity.[14] Therefore, large bonds will have a lower bid/ask spread, investors would incur lower transaction costs when selling, and they would demand a lower liquidity premium from the issuer.

In our analysis we report illiquidity related transaction costs separately for small and large bond sizes. In other words, the analysis shows an illiquidity cost for any bond with a positive bid-ask spread (i.e. all bonds). The term illiquidity premium is often used to describe the additional cost of a relatively illiquid bond to the more liquid ones. In our analysis, we compare the illiquidity cost of the small and large bonds, and the resulting difference can be considered illiquidity premium of the

[13] IHS Markit, Markit iBoxx GBP Benchmark Index Guide, September 2019

[14] In this analysis, large bonds are considered to be those with an issuance size above £250m. While this is not the same threshold as that used in the Markit iBoxx GBP Benchmark Index, the amount outstanding of a bond and its issuance size are sufficiently correlated for these thresholds to be comparable.

smaller company compared to the larger one, which the company is likely to have to pay to the investors when issuing bonds in the primary market.

3.2 Results

Relative Bid-Ask Spread

We calculate the average relative daily bid-ask spread of each bond over the previous five years, using data on bid, ask and mid-price of comparator bonds[15] from Bloomberg.[16] The bonds we selected for analysis share the following characteristics;

- maturity date between 2027 and 2033, with an average maturity year of 2030;
- data entries going back at least five years;
- denominated in GBP;
- larger than £70m
- UK bonds issued by a range of regulated utilities companies, and where there are multiple bonds from the same issuer, we have chosen at least one representative bond along with the criteria above.

First, the data shows a negative relationship between bond issuance size and the relative bid-ask spread, in particular for bonds with principals larger than £70m and smaller than £250m. In this category, a larger bond size can be clearly associated with smaller bid/ask spreads. For bonds with principals over £250m the evidence suggests a relatively stable bid/ask spread.

Next, we establish a threshold for large and small bonds to directly compare their liquidity based on the thresholds indicated in the data. We define large bonds as bonds with principals of larger than or equal to £250m. This aligns with the thresholds used by the iBoxx benchmark and it is the point where the relationship between bond size and bid/ask spread levels off in the data. As in our small notional company scenario the issuance is around £100m, we allocate bonds with a principal size between £70m and £130m to the small bond category, in order to compare to the large bonds

Figure 5 shows the results of our analysis. Small bonds are shown to have a higher bid-ask spread than large bonds, showing the existence of a liquidity premium.

Figure 5 5 Year Average Bid-Ask Spread By Bond Size Groups

Size of bond	5 year average Bid-Ask Spread	Number of comparator bonds	Average Size of Bonds (£m)
Small	1.46%	6	97
Large	0.60%	14	377

[15] We consider: *National Grid Electricity Transmission 2030, DWR Cymru Financing UK PLC 2031, Severn Trent Utilities Finance PLC 2028, Sutton and East Surrey Water PLC 2031, Yorkshire Water Finance 2033, Yorkshire Water Finance 2033, Western Power Distribution 2027, Anglian Water Services 2027, Yorkshire Water Finance 2029, Northern Gas Networks 2027, Yorkshire Water Finance 2032, Wales & West UTL FIN PLC 2030, London Power Networks 2027, South Eastern Power Networks 2031, Southern Electric Power Distribution 2031, Northumbrian Water Finance 2033, Southern Gas Networks PLC 2029, SSE PLC 2028, Centrica PLC 2029,* and *Western Power Distribution West Midlands 2032.*

[16] Bid-ask spread is calculated as the difference between the bid- and the ask-price, divided by the mid-price.

Source: Bloomberg data, Frontier Analysis

Note: Bid-ask spread is calculated as the difference between the bid- and the ask-price, divided by the mid-price.

In our sample, the smaller bonds on average have a relative bid-ask spread premium of 86bps compared to the large bonds.

Converting bid-ask spread into illiquidity cost

As explained above, illiquidity imposes a cost to the investor. Roughly speaking, this cost is equal to the bid-ask spread, if the bond is held to maturity. On an annual equivalent basis, this one-off cost can be spread across the years for which the bond is held.

From our analysis, large bonds would incur on average a bid-ask spread of 0.60% and small bonds 1.46%. In the context of our assumed tenor of 10 years, this one-off cost can be divided by 10 to estimate the average annual equivalent illiquidity cost. This is summarised in Figure 6 below.

Figure 6 Conversion of Bid-Ask Spread to illiquidity cost

	Small Bonds	Large Bonds
5 year average bid-ask spread	1.46%	0.60%
Years to Maturity (Sample Average)	10y	10y
Annualised Illiquidity Costs	14.6bps	6.0bps

Source: Bloomberg data, Frontier Analysis

Note: The bid-ask spread can be seen as a one-off cost to investors during trade which they need to be compensated for. One way to annualise this cost is to divide it by a typical holding period. We have used our assumed total tenor of the bonds (10 years) as the holding period.

The annual illiquidity cost is calculated to be 14.6 bps for small bonds and 6.0 bps for large bonds. The 9 bps difference between the two can be interpreted as an estimate of the illiquidity premium associated with a small company issuing small bonds with a “frequent” profile compared with it issuing large bonds with an “infrequent” profile or compared with a large company.

4 ISSUANCE COSTS

This section estimates the issuance costs on debt financing for a notional small and a notional large company. We make use of latest issuance cost information provided by ENWL, which we understand comes from its most recent bond issuance.

In order to issue bonds, firms incur issuance costs in addition to interest costs. Issuance costs relate, for example, to financial intermediaries' fees, road show costs, credit rating fees as well as legal and advisory fees. Whilst certain fee elements vary with bond sizes, a significant part of these issuance costs is fixed. Therefore, issuance costs as a percentage of the principal are higher for smaller bonds.

4.1 Our Approach

Cost assumptions

To compare issuance costs across bonds sizes, we adopt as a reference the cost that ENWL incurred when issuing its most recent bond in 2020. We note that although legal and advisory fees are fully fixed, some fees such as book runner fees and credit rating agency fees tend to have a component that is variable in the size of the issuance. In order to reflect the uncertainty in the fixed variable components of the book runner fees and credit agency fees, we have constructed plausible ranges based on information provided by ENWL.[17]

Figure 7 below summarises the total estimated issuance cost for the different financing profiles in our analysis.

Figure 7 Issuance cost for comparators

Company size	**Small**		**Large**
Financing profile	***Frequent***	***Infrequent***	***Frequent***
Debt issuance [£]	108m	324m	420m
Issuance costs			
Fixed [£]	0.8m	0.8m	0.8m
Semi-variable* [£]	0.6-0.7m	1.2-1.3m	1.5-1.6m
Total [£]	**1.4-1.5m**	**2.0-2.1m**	**2.3-2.4m**

Source: ENWL data, Frontier analysis

Note: Semi-variable costs include costs that have a variable component, but are also subject to minimum fees. These include items such as book runner fees and credit rating agency fees.

It can be seen that the fixed cost is the same across different sizes of the bonds and the variable cost is in proportion to the size of the bond.

[17] The fees incurred by ENWL, which are reported here, are only accurate at the exact size of its actual 2020 issuance (i.e. £300 million). Based on our understanding from ENWL, we have constructed a plausible range to reflect the fixed and variable proportions of the fees for the book runners and the credit rating agencies. The actual quotes from various banks and credit rating agencies may differ depending on the company asking for the service.

Conversion into annual interest terms

Next, our analysis converts these fees into annual interest rate terms. To do this, we incorporate this one-off issuance fee as a part of the cash outflow of a bond. The principal of the assumed bonds varies according to the financing profile and company size, but for comparability purposes, we assign the same coupon rates and time to maturity to all bonds in this analysis. These are 2.51% - 4.18% and 10 years, respectively.[18]

Using a discounted cash flow approach, we then calculate two internal rates of return (IRR) for the bond, one including these issuance costs, and the other excluding them. Figure 8 below provides more detail on this annualised issuance cost calculation. For this illustration, we consider the scenario with the lowest fixed costs and a bond rate equal to the lowest 10th percentile (2.51%) is assumed.

Figure 8 Issuance cost for notional small company issuing debt annually (in £m unless stated otherwise)

	IRR	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10
Small - Frequent												
Proceeds		108.0										
Coupon			-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7
Principal												-108.0
Cashflow		108.0	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-110.7
IRR	2.51%											
Transaction costs		-1.4										
Cashflow incl. issuance costs		106.6	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-110.7
IRR incl. transaction costs	2.66%											
Annualised issuance costs	**0.15%**											

Source: ENWL data, Frontier analysis

Note: Selected scenario is based on the lowest 10th percentile of bond returns and the lowest fixed costs assumption (£1.1m) and variable costs of £0.3m.

Starting by looking at the main cash flows associated with the bond, excluding the issuance cost, the stream of the cash flows generates an IRR of 2.51%, exactly equal to the assumed coupon rate. Adding the one-off issuance cost increases this IRR to 2.68%. The difference between this and the IRR absent one-off costs implies an annualised issuance cost of 0.15 bps for this bond.

In a similar manner, we repeat the same analysis for the other two financing profiles, a small firm that issues infrequently and a large firm issuing debt annually.

4.2 Results

Figure 9 below summarises the outcomes of the issuance costs analysis:

Figure 9 Issuance costs overview

Company size	Small		Large
Financing profile	***Frequent***	***Infrequent***	***Frequent***
Debt issuance [£]	108m	324m	420m
Issuance costs [£]	1.4-1.5m	2.1m	2.3-2.4m
Issuance costs (as IRR premium)	**15-18bps**	**7-8bps**	**6-7bps**

Source: Frontier Analysis, cost data provided by ENWL

[18] The coupon rate assumed and the time to maturity are as assumed in the rest of the analysis.

In annualised terms, our results show that a notional small company incurs a higher issuance costs in the range of 9-11 bps when it issues debt annually compared to a larger company.

5 COST OF CASH CARRY

This section presents our analysis on cash carrying costs for the three financing profiles considered. Cash carry costs arise through companies hold cash on the balance sheet that typically only earns short-term deposit interest rates, but the company will be paying the long-term borrowing rate (coupon rate on the bond).

Companies need to hold cash on the balance sheet for various purposes, including day-to-day cash and liquidity management and to ensure sufficient funds are available to meet financial liabilities as they fall due. An example of a financial liability is the repayment (re-financing) of maturing existing debt.

To protect against potential disruption and dislocation in capital funding markets, companies will typically seek secure committed funding or facilities well in advance of payment dates. This is often embedded in the company's Treasury policy and typically covers periods of 12-18 months in advance.

The size of the refinancing relative to the company can have an impact on the options available, we look into this in more detail in our analysis. In this regard, the frequency of a company issuing debt (and re-financing) also can have an impact on the relative carrying cost.

We have chosen to focus on cash held for the purpose of refinancing only because this cost tends to vary according to the size of the company. In contrast, we assume that the cash held for the purpose of day-to-day liquidity management carries a similar level of cost across different sizes of companies. Therefore, our estimate of the cost of carry does not cover all elements of cash carrying costs such as those included in Ofgem's own analysis on transaction costs for RIIO2.

5.1 Our Approach

Cost assumptions

We are focusing on how the cash carrying cost in relation to refinancing may differ between companies.. We understand from ENWL that when re-financing maturing existing bonds, companies have a number of options, with various degrees of availability and costs:[19]

- Pre-financing: this is the relatively straightforward option of issuing a new bond in advance of the maturity of the existing bond, which requires holding the cash on the balance sheet for a period of time; or
- Committed bank facility: this is a back-up facility that could be used in the event of capital market dislocation (e.g. credit crunch) where new debt cannot be issued. Companies with committed facilities can plan to issue debt much closer to the repayment date of maturing debt, largely avoiding pre-financing costs.

In the case of pre-financing, the company pays interest on both the bond that is maturing and on the new bond simultaneously. A small mitigating factor are interest receipts that a company generates on its cash holdings. For the small and large

[19] We understand from ENWL that another option called forward stating financing is sometimes also available in selected markets. But as these can be unreliable, we have discarded it from our analysis.

notional company, the analysis assumes an interest rate on cash holdings of 0.5%-2.5% (based on the P90 and P10 of the LIBID rate in the past five years).[20]

In the case of committed bank facility, the timing to issue new bonds can be postponed to coincide with the maturity date of the existing bond. A committed bank facility offers flexible financing that can be directly drawn from banks and the facility therefore credibly guarantees liquidity until the new bond has been issued. However, the size of a committed bank facility is typically limited, often in proportion to the size of the RAV.

Where refinancing is facilitated by committed bank facility, we consider related commitment fees in our transaction cost calculation. Commitment fees compensate banks for the commitment to lend and are payable independent of whether the facility is drawn or not. We note that in securing the liquidity requirements, we do not assume that the facility is actually drawn down, which would lead to additional costs such as interest costs and utilisation fees.

As there is limited public information on the pricing of committed facilities, our assumption on the commitment fee rate relies on conservative cost estimates provided by ENWL in respect of its Revolving Credit Facility (RCF). Based on this, we calculate the commitment fee rate as 25% of the interest margin (i.e. the increment over the LIBOR rate – assumed to be 35bps).[21] The commitment fee rate therefore is estimated to be approximately 9bps and will be applied to the size of the committed facility, which is assumed to be equal to the refinancing need in our analysis.

Cost of carry calculations

Figure 10 below shows the different scenarios in relation to the cost of carry.

Figure 10 Costs of cash carry by company size and financing profile

Company size	Small		Large
Financing profile	***Frequent***	***Infrequent***	***Frequent***
RAV [£]	1800m		7000m
Debt issuance [£]	108m	324m	420m
Bond / RAV	6%	18%	6%
Costs of cash carry [£]	**0.1m**	**5.4-6.5m**	**0.4m**

Source: Frontier analysis

As shown in the table above, a company of ENWL's size which issues debt annually would need each bond issuance to cover 6% of its RAV. This could be reasonably covered by committed facilities at a competitive price.

On the other hand, our notional small company with an infrequent financing profile would need a committed facility covering 18% of its RAV. We understand from ENWL, that an committed bank facility covering 18% of RAV would unlikely be available without incurring prohibitively high additional costs which would undermine the purpose of the committed back-up facility.

[20] The London Interbank Bid Rate (LIBID) is the rate at which banks rate at which a bank is willing to borrow from other banks. This is usually 12.5bps below the LIBOR, the banks' offer rate.

[21] This is conservative as we understand from ENWL that for companies with lower credit rating, the commitment fee can be as high as 50% of the interest margin.

We therefore assume that for the infrequent financing profile the notional small company needs to pre-finance by issuing a new bond at least 12 months ahead of the maturity date of the existing bond. Using our ranges for the debt interest rates and cash interest rates, the difference between the interest cost and interest income on the excess cash of £324m implies a cash carry cost in the range of £5.4m-6.5m.

In the two scenarios where the refinancing is facilitated by the committed facility (the small and large companies with frequent financing profiles), the commitment fees, which are calculated to be approximately 9 bps above, are accounted for in the cost of carry shown in Figure 10.

Conversion into annual interest terms

Similar to the issuance costs analysis, the next step is to convert these costs into annual interest rate terms. Again, our analysis considers the respective principal amount for each company, with a coupon rate of 2.51%-4.18% and time to maturity of 10 years for all firms. Using a similar principle, the annualised cash carry costs are calculated as the difference between an internal rate of return of the bond excluding the cash carry costs and including the cash carry costs in the cash flow of the bond (see Figure 11). For this illustration, we consider the scenario assuming the lowest 10th percentile returns for bonds and the lowest 10th percentile of LIBID rates.

Figure 11 Costs of cash carry for a notional small company issuing debt every three years (in £ million unless stated otherwise)

	IRR	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10
Proceeds		324										
Coupon			-8	-8	-8	-8	-8	-8	-8	-8	-8	-8
Principal												-324
Cashflow		324	-8	-8	-8	-8	-8	-8	-8	-8	-8	-332
IRR	2.51%											
Cash carrying costs		-7										
Cashflow incl. CC costs		317	-8	-8	-8	-8	-8	-8	-8	-8	-8	-332
IRR incl. transaction costs	2.74%											
Annualised issuance costs	**0.23%**											

Source: ENWL data, Frontier analysis

5.2 Results

As can be seen in Figure 12, the costs of cash carry for the small firms with an infrequent financing profile are estimated to be 21-23 bps, whilst the firms issuing debt annually incur very little costs of cash carry (only 1 bps due to facility commitment fees).

Figure 12 Overview of cash carry costs

Company size	Small		Large
Financing profile	*Frequent*	*Infrequent*	*Frequent*
Costs of cash carry	**1bps**	**21-23bps**	**1bps**

Source: Frontier Analysis

This is because firms who issue small amounts of debt in relation to their RAV could rely on committed facility to finance the maturing bond and such companies would therefore be able to avoid having to issue a new bond 12 months in advance of an existing bond maturing.

6 TRANSACTION COST DIFFERENTIAL

6.1 Transaction cost by scenario

As shown in the previous three sections, the source and size of the transaction costs vary for each of the notional companies and financing profiles;

- For a notional large company these costs are more straight forward to calculate. It could issue bonds worth more than £250m every year and would incur some illiquidity costs, some issuance costs and no cash carrying costs for refinancing;
- A notional small company would be on either of two financing profiles. It would either issue debt annually and save on cash carry costs, or it would issue debt infrequently (such as every three years) and would therefore avoid high illiquidity costs and high issuance costs.

Figure 13 below summarises the results of our transaction cost analysis. Our results suggest that the large company incurs the lowest transaction costs whilst the small company, in either financing profile scenario, incurs higher transaction costs.

Figure 13 Overview of transaction costs by scenario

Company size	**Small**		**Large**
Financing profile	***Frequent***	***Infrequent***	***Frequent***
Key assumptions			
RAV [£]	1800m		7000m
Debt issuance [£]	108m	324m	420m
Issuing frequency	1y	3y	1y
Illiquidity costs	✓ 15bps	✓ 6bps	✓ 6bps
Issuance costs	✓ 15-18bps	✓ 7-8bps	✓ 6-7bps
Costs of Cash carry	✗ 1bps	✓ 21-23bps	✗ 1bps
Total transaction costs	**31-34bps**	**35-37bps**	**13-14bps**

Source: Frontier Analysis

In particular, our results show that a frequent financing profile for a small company can incur a similar level of transaction cost than an infrequent one, depending on the exact conditions. If one considered a company even smaller than ENWL's current size, it would be plausible to observe that frequent issuance being materially more costly than infrequent issuance.

In addition, we note that the quantitative analysis above does not take account of any opportunity cost of managerial and business resources spent on major financing events. A smaller company is likely to face a proportionately larger strain on its management resources than a larger company with a larger treasury function. This unmeasured opportunity cost can be significant and would further tilt the total transaction cost comparison in favour of the infrequent financing profile for a smaller company.

As a conservative measure, we have chosen the financing profile that is the least costly to compare with the larger companies transaction costs. In reality, it is likely to be unfeasible for an infrequent issuer to suddenly switch to frequently issuing (e.g. the re-financing of an existing large bond cannot easily be done through a series of frequent but consecutive smaller issuances because there will be a shortage of cash to repay the maturing debt). In reality, there will be an element of path dependency in the financing profile of smaller companies. But we have not focused on that point in this study.

In conclusion, as our analysis has shown, the transaction costs differential between small and large companies can be significant. As shown in Figure 13 above, our results support an estimate of the differential in the range of 18-20 bps, (in terms of cost of debt), attributed to higher transaction costs.

6.2 Regulatory Precedent

This section highlights previous cases where allowances have been made in cost of debt calculations for illiquidity costs, issuance costs and for the cost of carrying excess cash. In addition, specific examples of company-specific small company premiums are also summarised.

Illiquidity Costs

During the GD17 price control review (2017 to 2023 regulatory period for gas distribution network operators) in Northern Ireland, The Utility Regulator provided Phoenix and firmus with a 40 bps uplift on the allowed cost of new debt attributable to illiquidity.[22] We note that the estimation of the illiquidity was made on the basis of higher yield to maturity of the relevant bonds than the benchmark rather than higher bid-ask spread.

Issuance costs

There is ample regulatory precedent on the inclusion of issuance costs within the cost of debt allowance.

In Ofwat's PR19 final decision on the allowed return on capital for 2020-25, it included an allowance of 6 bps in cost of debt calculations for issuance costs. In PR14, Ofwat allowed 10 bps in the cost of debt allowance for issuance fees. In both cases, the allowance was applied to all of Ofwat's regulated companies.[23]

In addition to the two cases above, the Utility Regulator in Northern Ireland has given company specific uplifts based on issuance costs in the past. In GD17 the Utility Regulator gave transaction cost allowances to Phoenix (40 bps on embedded debt, 30 basis points on new debt) and firmus (60 bps on all debt) in

[22] The Utility Regulator, Price Control for Northern Ireland's Gas Distribution Networks GD17 - Final Determination, September 2016

[23] Ofwat, PR19 Final Determinations – Allowed return on capital technical appendix, December 2019

addition to the allowances for illiquidity costs mentioned above. The Utility Regulator's report suggests that the transaction cost allowance was mainly due to costs associated with issuing debt.[24] In addition, in the 2017 price control for the transmission and distribution company, Northern Ireland Electricity Networks (NIEN), NIEN were allowed 20 bps on the cost of all debt to cover issuance costs and fees.[25]

Costs of Carrying Excess Cash

Costs of having excess cash have been previously highlighted as a potential source of uplift on the cost of debt allowance by Ofwat and the CMA.

In its PR19 final decision, Ofwat made an allowance of 4 basis points attributed to additional costs of cash carrying.

The CMA have also acknowledged that there are additional costs due to carrying excess cash. In the 2015 Bristol Water appeal of Ofwat's PR14 price determination, the CMA used a 20 bps estimate for cash carry costs when looking at the actual cost of debt of Bristol Water. The inclusion of this suggests that the CMA considered that additional costs for smaller firms due to carrying excess cash were important for cost of debt allowance.[26]

Small company premium

In the Ofwat PR19 final decision, Ofwat used notional companies to calculate a company-specific uplift.[27] In addition to the allowance given to all firms due to issuance costs and costs of carrying excess cash, Ofwat calculated that the appropriate overall uplift for a notional small company relative to its overall cost of debt allowance was 33 basis points on the overall cost of debt. This uplift was given to two small companies. This highlights a case when company-specific uplifts have been awarded.

Ofwat additionally allowed explicit small company premiums in PR09 and PR14. In the 2015 Bristol Water appeal of Ofwat's PR14 decisions, the CMA allowed a small company premium of 40 bps.[28]

Summary of precedent

As seen from the non-exhaustive list of examples above, there is regulatory precedent for the allowance of uplifts on the cost of debt for illiquidity costs, issuance costs and the cost of carrying excess cash. There is precedent for company-specific uplift attributed to small companies.

[24] The Utility Regulator, Price Control for Northern Ireland's Gas Distribution Networks GD17 - Final Determination, September 2016

[25] The Utility Regulator, Northern Ireland Electricity Networks Ltd - Transmission & Distribution 6th Price Control (RP6) – Final Determination, June 2017

[26] CMA, Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991 - Appendices 5.1 – 11.1 and glossary, October 2015

[27] Ofwat, PR19 Final Determinations – Allowed return on capital technical appendix, December 2019

[28] CMA, Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991 – Report, October 2015

6.3 Conclusion

In conclusion, we find that regardless of financing profile, a smaller company like ENWL would incur higher transaction costs on debt financing than a large company. This additional cost is structural and cannot be fully mitigated.

The difference between the transaction costs of a large company issuing debt frequently and the most cost effective way of financing strategy that a notional small company can choose is proven to be material and significant. More specifically, we find a smaller company with size similar to that of ENWL would incur additional transaction costs of 18-20 bps on the cost of debt, in addition to interest cost.

We consider that there is reasonable justification for the regulator to make an explicit additional allowance over the sector debt allowance in the range of 18-20 bps for smaller companies, to contribute to the premium they face on smaller and/or more infrequent debt issuances.

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