RIIO-2 (Cross Sector) Sector Specific Methodology – SPEN Response

Output categories questions

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

We have reviewed the proposal as set out at paragraph 2.20 that would allow Ofgem to make further licence modifications (to both appealing and non-appealing licensees) after an appeal to the Competition and Markets Authority (CMA). It is not clear to us from this paragraph what exactly Ofgem's proposals are. We would therefore ask Ofgem to explain its proposals in more detail, including the nature and legal basis of the discretionary mechanism, and an explanation of the problem(s) Ofgem is trying to address through the introduction of the measure. It would also be helpful if Ofgem could provide some practical examples of the circumstances in which Ofgem envisages utilising any such measure.

Ofgem state that they will have "due regard" to the CMA's determination and directions in any successful appeal, and the need to maintain the integrity of an effective appeals mechanism. We consider that the statutory appeals process already presents the flexibility that would permit Ofgem and the CMA to consider any relevant links between challenged parts of the price control decision and unchallenged parts in the context of any appeal. In the British Gas Trading (BGT) and Northern Powergrid (NPg) price control appeals, the CMA confirmed in its final determination reports that if evidence was presented that suggested that overturning one part of the price control decision would have knock-on consequences for other unappealed aspects of the decision, the CMA would consider any such links on a case-by-case basis. The CMA noted they would expect Ofgem, at least in the first instance, to highlight and address these links in its response.[1] As part of the remedies available to it, the CMA may then remit the matter back to Ofgem for reconsideration. We therefore submit that an appropriate channel already exists, through the statutory appeal process, for Ofgem to propose and evidence any necessary changes to other components of the price control which are affected by the appeal. Using this pre-existing mechanism would ensure the integrity of the appeals mechanism is maintained.

We would welcome clarification from Ofgem of the other circumstances that it may seek to use any discretionary mechanism that they introduce, outside this CMA mechanism.

We are alert to the risk that many different parties may seek to appeal Ofgem's RIIO-2 price control modifications. Given the lack of clarity about Ofgem's intentions behind these proposals, we have assumed that Ofgem's proposals might be at least partly driven by case management concerns. In light of this, we are keen to have a discussion with Ofgem about the potential case management risks and mitigations to ensure any disputes are dealt with fairly and efficiently through the CMA appeal process. SPEN would also like to discuss ways of ensuring that matters in dispute have been aired and focused in pre-appeal discussions between all potential appellants and Ofgem.

In this context, we would also note the letter from Andrew Tyrie to BEIS dated 21 February 2019 which sets out a range of proposed reforms from the CMA. One proposal states that there is a "strong case" for removing responsibility for regulatory appeals from the CMA and suggests the review of

[1] See BGT Final Determination report (29 September 2015) paragraphs 3.50 – 3.54 and NPg Final Determination report (29 September 2015) paragraphs 3.49 – 3.53

economic regulatory decisions could be consolidated in the courts.[2] We assume Ofgem will be keeping these proposals and any developments under review.

Reflecting what consumers want and value from networks

Output categories questions

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

The three proposed new output categories look reasonable and sensible.

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

No, we agree with what has been proposed. All aspects of our business activities can be included within any one of the three categories proposed.

Overarching outputs framework questions

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

In paragraph 4.10 Ofgem mentions "consequences for failure to deliver." In reaching its RIIO-2 decisions, we think it is important that Ofgem performs cross checks to ensure that it does not inadvertently drive the industry to be overly cautious, e.g. by weakening the incentive to innovate and try new ways of doing things which will be to the consumers' benefit. RIIO-T2 is an extremely important review period for the GB transmission system. It will be the price control period which further facilitates the increase in electric vehicles and the start of a shift to renewable domestic heating sources. Given the challenges associated with the GB's transition to a low carbon economy, network companies should be investing and delivering ahead of need to deal with the changing demand scenario forecasts, and we consider that the RIIO-T2 framework should be designed to allow for anticipatory investment, in appropriate circumstances.

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

We do not believe that dynamic and relative incentives will drive the right behaviours amongst companies. Each network operator is responsible for its own licence area which can vary greatly in terms of size, geography, customer numbers, technical challenges and local economies. Therefore, each licensee is different in the way it operates and is managed and must focus on what its customers and wider stakeholders ask of it. We would be happy to work further with Ofgem to ensure that companies can continue to collaborate in order to learn from best practice and share innovation to consumers' benefit.

Bespoke outputs questions

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

[2] Page 40
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/781151/Letter_from_Andrew_Tyrie_to_the_Secretary_of_State_BEIS.pdf)

We do agree with the proposals. Companies can vary greatly in terms of their customers' needs, therefore, there may be a requirement for a company specific Output Deliverable Incentive (ODI). However, this must be carried out on a level playing field so that one licensee is not excluded from having an ODI which they and their customers could would also be able to benefit from. Ofgem should review all bespoke ODIs to ensure that they are only applicable to one licensee and not all.

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

None that are apparent, however we will keep this under review as work on ODIs develops.

Enabling whole system solutions Questions

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

This consultation document has a number of differences from the whole system consultation referenced in paragraph 5.8 and being consulted on in parallel. In particular the definition of whole system is different in both consultation documents which we consider will lead to confusion, as in the early years of RIIO-2, DNOs and IDNOs will have one definition, but those in the RIIO-2 process will have a different whole system definition within their licence.

We refer Ofgem to the response we provided to the recent consultation on a Whole Systems licence obligation and remain of the view that Ofgem should publish a Whole Systems guidance document, setting out its policy for a Whole Systems approach, following completion of the RIIO-2 price control process. This would also allow time for the work being done through the on-going ENA's Open Networks project to be completed.

Without the need for the proposed licence changes we are already, as a responsible network operator, applying, and delivering Whole Systems solutions in accordance with our broad obligations, to work in an efficient, economic and co-ordinated manner wherever appropriate.

We believe that the proposed definition is too narrow for a truly whole system approach to be considered. The current proposal places an emphasis on greater network coordination, but not a whole system level approach. Emphasis is placed on coordination across distribution and transmission networks which is appropriate, as well as the concept of gas and electricity coordination. However, we consider that the opportunities flowing from these proposals will be limited.

Section 5.8 suggests that if the current system is left un-touched, this would produce sub-optimal coordination. This is incorrect. It needs to be recognised that changes to the system and the need for whole system coordination is driven by changes by consumers and users of the network – changes to supply or demand. Failure to recognise the wider definition of whole system leads to network coordination rather than a whole systems approach.

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

Having a broader definition would not necessarily lead to network consumers funding some of the elements that are described in section 5.17, but it would require network companies to consider the wider implications. There is also an implicit reference to whole system planning being associated with demand. Section 5.16 only references the demand element, yet some of the best examples of whole system coordination to date, have been through network coordination across the DNO, the TO and the ESO for connecting new generation, like SPEN has achieved in Dumfries and Galloway in managing the connection of substantial amounts of new renewable generation. Ofgem have cited the fact that they do not regulate external sectors, however, a definition which requires companies to consider the impact of these factors, does not impact the current regulatory boundaries.

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

A broader definition is likely to achieve greater benefits for consumers. The proposed definition does not give adequate emphasis on coordination with generation, demand or other relevant parties who could make a valuable contribution to a more optimal outcome. The cost of connecting generation and demand has a cost which is partially socialised therefore there is a consumer benefit from optimising this where possible.

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

Our response to this question is incorporated into our response to CSQ12, below.

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

Our views on the various mechanisms are:

1. We agree with the criteria as part of the business plan incentive. Consideration of a whole system approach is important in the evaluation of the business plan. An upfront incentive is important to recognise, and reward upfront planning, which is embedded in the business plan and would not then be eligible for further reward in the price review. The proposal to penalise companies who are underperforming against this criteria, should be proportionate to the benefit lost to consumers. The opportunity for taking a whole system approach may be limited for some network operators and they should not be unfairly penalised for this in the same way that Ofgem identify any reward should be commensurate with the benefit that consumers receive.

2. The proposal to allow the use of innovation funding to address whole system approaches is positive. It provides a funding route for costs which would not be considered at the time the business plans were developed and allows companies to flex their approach. What is not clear in the guidance is whether the use of innovation funding for whole system approaches would only be where the approach is innovative, of if the funding could be used where coordination is the right thing but an allowance is not available in the price review – in effect a substitute for a re-opener. Should proposal 6 be progressed, then it would be reasonable to limit this option to only being available for innovative approaches.

3. We do not see how such an incentive could be easily measured or tracked, to provide a robust means of justifying a reward or penalty. There has been significant learning from the Environmental Discretionary Reward on the degree of subjectivity of such rewards. We would be concerned that this approach could be similarly subjective and bureaucratic for network operators and Ofgem to administer.

4. A consideration of the whole system, needs to be taken into account in the creation of all output categories that are created for RIIO-2, to minimise the risk of inefficient outcomes. Whilst we do not expect inefficient outcomes, a wider consideration needs to be adopted as any output or incentive is defined. The use of the totex sharing mechanism plays a major role in incentivising innovative approaches which can involve a whole systems approach. In particular, where new ways of coordinating new generation onto the network allows the connections and associated reinforcement to be undertaken, at a lower cost.

5. A re-opener mechanism would allow for adjustment. However, this would most likely need to be aligned with T2/GD2 and ED2, therefore would not lend itself to a mid-period review. The drive for whole system coordination will largely be driven by changing customer needs, such as new connections or network loading, which may not be able to wait till the trigger point for a re-opener. A flexible approach is required to ensure network operators can undertake the best approach, rather than being restricted by funding windows. As whole system

approaches will be driven by customers connecting to the network, the risk of a re-opener approach is that network operators will delay investment until such time that the re-opener is available, which may not be in the customer's interests. A re-opener typically has a materiality threshold, and whole system solutions individually, may not achieve this level. We believe that further discussion with real examples are required to consider how this approach may work in practice including ensuring any re-opener is clearly and tightly defined.

6. The use of a whole system discretionary funding mechanism would allow more flexibility, than a re-opener, but is likely to be very subjective. It is not clear if this is purely a funding mechanism or a reward mechanism as well. Given the definition in section 5.38 of evidence of network operators pushing boundaries, we would expect this to have an associated reward to recognise the risk and efforts that a network operator has undertaken to achieve this. Where an incentive based approach is taken, consideration needs to be given to (i) the recipient to which the whole system approach is being taken (ii) the network operator who is avoiding costs by engaging another operator, yet still incurring costs to enable this to happen without a direct deliverable, or (iii) the operator undertaking the additional works. This is not defined but will be important in considering how any mechanism would operate. Close cooperation between these parties is required and recognition needs to be given that creating competition in this area, is not conducive to an optimal and coordinated outcome.

No mention is made in the consultation document of proposals for including IDNOs or IGTs into these whole system mechanisms, as is recognised in the parallel consultation on whole system approaches for RIIO-1. This further underlines the need for Ofgem to set out its policy for a Whole Systems approach, following completion of the RIIO-2 price control process.

There is also an interaction with the Whole System approach and other parts of the price review. In particular, the definition of Licence Obligations and Price Control Deliverables (PCDs) in section 4 is understandably robust. Section 4 outlines that PCDs are delivered to a stated specification, budget or timing (section 4.16). Yet over the course of a price review, a whole system approach may change this and it should not result in the network operator being penalised. This will need to be weighed up with the desire of achieving a whole system approach.

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

We are of the view that the need to transfer revenues should be a failsafe position and with the adequate use of re-openers, network operators should not be proposing projects where it is reasonably foreseeable, that the party responsible for delivery may change.

Should a mechanism be required to transfer revenues and outputs, consideration needs to be given to who makes the assessment of the cost efficiency of alternative approaches. If the TO has to transfer funds to the DNO, or another party, as the solution on offer is lower cost, that does not necessarily mean it is an efficient cost. For example, a DNO can provide a reactor connected to the Distribution network at a lower cost, however a means of assessing the efficiency of this needs to be considered, such that the other party is not making a higher return. Where different solutions are being proposed, the benefits may not be readily comparable and a means of trading these off will need to be made.

Ofgem's work should recognise the rules and procedures which are already in place for proper allocation of costs at the boundary of transmission and distribution networks. It should also consider the benefits of holding over the funding of Whole Systems projects until both transmission and distribution solutions can be considered.

Business plans should be designed to minimise the need to transfer revenues in the period by actively considering whole system approaches from the outset.

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

There are no other mechanisms that we can suggest at this time. However, a means of sharing the whole system benefits is required, which will sufficiently incentivise an operator not to invest and get credit for this, whilst also benefitting the party that is undertaking the expenditure.

A whole system incentive for RIIO-T2 will need to be carefully designed to ensure consumer benefits will be realised, for two overarching reasons. Firstly, given the limited time between Ofgem's decision in May and the submission of our business plan, to the Consumer Challenge Group, in July. The opportunity for transmission companies to establish whole system solutions is limited and may depend significantly on solutions involving distribution companies or the ESO. It will take time to develop these solutions and could require funding to be available across the different companies. With the transmission price control being determined first, this could bring a misalignment in funding provision, or certainty, that could hinder implementation of whole system solutions. Therefore, a whole system incentive should reward an approach or strategy, for identifying where whole system solutions could be realised over the price control period, as well as rewarding solutions that can be explicitly identified in the business plan submission.

Secondly, the role of transmission companies in the running of market tenders or contracting commercial services is limited by their existing licence obligations (see our response to CSQ12 above). Whole system solutions that rely on non-build commercial aspects require the ESO or future DSO's or other 3rd party providers to contract services through new or established markets. TOs, at this point, should not be incentivised to provide this service, to avoid the risk of undermining current market mechanisms or adopting broader roles than they are currently licenced to do. This dependency needs to be accommodated within any business plan incentive.

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

We have no further proposals to add.

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

We have nothing specific to add, beyond the comments made in response to the questions above.

More generally, we are mindful of our wider competition law obligations and look forward to working with Ofgem, to demonstrate that we always meet those obligations, and develop a Whole Systems approach in those instances where it is to the consumers' benefit. We recognise that the rapidly changing nature of the energy related markets means that it will be particularly important for us to work closely with Ofgem and other stakeholders to achieve this.

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

Network operators have certain non-financial licence obligations, such as the obligation to provide an offer, even where the customer a choice can lead to sub-optimal outcomes for the consumer. For example, we have seen instances where a customer opts to connect to either the distribution or transmission network, where connection to another part of the network offers a lower cost to the network operator (thus consumers). Charging reform may address this however it demonstrates barriers exist that can limit whole system optimisation.

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

A re-opener approach to allow elements of the price review to be re-visited would be the most appropriate approach. Some of these areas will continue to evolve in the RIIO-2 period and trying to develop a sophisticated mechanism risks the mechanism becoming a barrier in itself. However, as with all re-openers, it must be very clearly and tightly scoped in advance.

Ensuring future resilience

Asset Resilience Questions

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

Monetised risk is embedded within the asset management practices across SPEN.

SPT has been engaged with Ofgem and other TOs over the last few years to develop a common methodology to quantify network asset risk at the transmission level.

At the distribution level, SP Distribution (SPD) and SP Manweb have been working closely with Ofgem and the other DNOs for over 5 years and have collaboratively implemented a common method for assessing and reporting network asset risk. SPD's ED1 plans have been restated and they have been reporting using this method since 2016.

Considerable effort has been put into the development, calibration, testing and validation of these methodologies. The result is robust condition based methodologies covering both our transmission and distribution networks. These describe the current and future condition of the lead network assets, their criticality and therefore the network risk represented by these assets. The use of monetised risk allows comparison between different types of lead assets and also facilitates the prioritisation of certain interventions, in a consistent manner.

Whilst we agree on the use of monetised risk as one of the key considerations in the justification of investment proposals, we believe that its use in isolation to justify the investment would not lead to robust outcomes for consumers. Instead, we believe the condition of the assets should be the starting point in the determination of whether an asset requires intervention. Monetised risk is useful in planning and prioritising asset interventions. The probability of failure of an asset, based on its observed and measured condition, is the key determinant of whether an intervention is necessary for an asset, ensuring that asset and network risk are managed efficiently.

The same high standard of service should be available to all users of our transmission and distribution networks. Focusing on monetised risk to justify investment proposals, without detailed consideration of the components of the risk, could lead to poor asset management decisions on lower consequence assets which are approaching the end of their operational life. The monetised risk is derived from the probability of failure (health) and consequences of that failure (criticality) but they do not contribute to the risk value in the same way. Therefore the health of the asset should be the "primary" criteria to target the assets requiring an intervention.

The use of monetised risk allows network owners to manage their portfolio of assets ensuring that the work required can be expressed on a common basis, demonstrating the effect of the actions on the risk of the network as a whole.

Similarly, the setting of a monetised risk objective requires careful consideration of not only the monetised risk of the individual assets, that comprise the risk value, but also the condition (or health) of those assets. The value of monetised risk at a whole network level is not sufficiently meaningful if considered in isolation, without a more granular understanding of its components. This ensures that the risk objective is informed by a strategy to intervene on the right assets at the right time. It is important that licensees demonstrate how they have used their detailed knowledge of their asset base to determine a long-term plan for interventions and that, where appropriate, these are supported by CBAs. This process will define the risk objectives at various points in time and will give stakeholders confidence that there is sound stewardship of the assets and transparency in the derivation of benefits. It is also important to be mindful that network reliability, particularly in electricity transmission is also critically dependent on the condition and risk represented by assets not covered by the monetised risk methodology. The licensee's view of its risk objectives should therefore not place undue emphasis on the monetised risk number to the exclusion of a holistic approach.

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

The approach to using a relative measure of risk across all sectors is welcome, however it is important to keep in context that this is a relative measure and therefore is not directly comparable across sectors. It should also be recognised that each sector has developed a risk methodology which is reflective of their own sector and therefore differences in approach will be intrinsic in the application of the various methodologies.

A relative target in monetised risk provides a more direct link between proposed intervention activities and outputs; yet it still retains flexibility to react to emerging risks.

We believe that targeting an absolute level of monetised risk could be sensitive to background changes in monetised risk outside network companies' control. The proposed approach therefore provides greater certainty that companies deliver the level of risk reduction originally outlined in their plans. The consumers will ultimately benefit from this approach as they would only pay for the cost of the works carried out in the price control removing uncertainties from the absolute risk target.

Given the timescales that Ofgem has set for development and delivery of our Business plan, it is critical that the details of the implementation of the mechanism are resolved as a matter of urgency.

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

SPEN has always taken a longer term view of the sustainability and effectiveness of our asset interventions. With this in mind we support, in principle, a mechanism by which a long term measure of the effectiveness of an intervention is defined. However, the definition and implementation of this measure must be robustly defined. We look forward to working with Ofgem and the other network companies to further define this.

Whilst we are supportive of proposals for defining a long-term measure as a forward looking indicator of the value for consumers, we are very concerned about the maturity of this approach at this stage. We are concerned over the timescales involved to define and implement measures which are common within each sector. The timescales afford insufficient opportunity to adequately test robustness.

The proposed measure would introduce significantly more complexity into an already complex approach. We are concerned about the practicalities required to implement an effective measure of long term benefit within the available timescales. In particular, the investment and implementation in IT systems, business processes and engineering practices to enable plan development and subsequent regulatory reporting.

A key consideration is that within a regulatory time period the long term monetised risk benefit can only be forecast, based on the best information available at the time. There are a number of outstanding details to be resolved to allow licensees to calculate the benefits, the end of period risk targets and the mechanisms for reporting. Approaches taken in ED1 could represent an appropriate starting point for relative risk measures but further development to extend this to the long-term approach remains outstanding.

The lack of alignment of lead asset categories between companies in the ET sector prevents Ofgem from undertaking accurate comparisons between companies due to the materiality of the impact on network level monetised risk that this causes. The ED sector companies are currently working towards reporting a common set of asset categories ahead of ED2 and will seek to extend the asset categories covered by NARM during ED2.

It is clear that a number of areas still require clarity. It is therefore critical that the detail behind the implementation of the mechanism is agreed as a matter of urgency.

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

We broadly agree with the approach outlined in relation to setting outputs and welcome the opportunity to develop a business plan which focuses on the key points set out. However, we do not agree with the use of monetised risk to set allowances. While monetised risk is a good measure of the benefit derived from an intervention, it is also important to remember that this is not directly comparable to the finance cost incurred in delivering the most efficient interventions across a population of assets, and each intervention cost should be considered on its own merits.

We have concerns in regards to the intended use of the monetised risk for benchmarking the companies' proposals. Monetised risk cannot be directly compared between companies because the lead asset categories differ between licensees within the same sector, and also because monetised risk is heavily dependent on the network characteristics, asset population and present asset condition.

We would welcome guidance on how all the elements may be reported, to ensure consistency and transparency that is reflective of the present and future risk for the interventions we plan and then deliver. We envisage that some of this reporting could build upon reporting developments from the ED sector.

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

Option 2 of allowing a fixed pot of money in RIIO-2 for funding outputs which is subsequently trued-up at the end is preferable. Option 1 would expose companies to justifiable costs with no means of funding and is likely to result in greater peaks and troughs between price reviews to minimise the cost exposure for companies. This decision should be consistent with load related expenditure.

We agree with the proposed Option 2. The price control boundary should not have an impact on our asset management activities.

Within the ET sector, project development is often lengthy with many of the schemes spanning across price controls. Option 1 may have an impact on efficient project planning as we have seen through the current price control. Companies' internal financial governance would require a commitment on expenditure to be funded years ahead of delivery and it is not possible to progress that without certainty of the funding mechanism.

We agree that funding arrangements should ensure consumers do not pay for work that does not deliver any benefits within the first price control period. However an efficient asset management strategy and project planning may require works that incur costs in one price control period, even if outputs are not delivered until the project is commissioned in another. It is a feature of complex, large scale transmission projects that there can be significant construction and pre-construction works required prior to the commissioning of assets. While the counting of output in terms of monetised risk delivery may occur later, these works are necessary elements of activities agreed to be in consumers' interests. We are therefore supportive of Option 2 and we would like to engage in further discussions around how to measure progress within the first price control.

Within the ED sector, delivery timescales of major projects, particularly at 132kV, can be lengthy. In RIIO-ED1, individual projects exceeding £25m are designated as High Value Projects. The costs and outputs for these are determined individually at the start of the price control and are reported on separately. Occasionally these projects span into the next price control and are trued-up. This appears broadly similar to Option 2 presented within the consultation.

It is worth noting that for the ED sector, the scope of the proposed Option 2 would need to be limited to only High Value Projects. It would be neither practicable, nor efficient to individually determine on every cost, volume and risk on small schemes spanning the last month of the period. There will inevitably be a level of in-progress projects which are claimed during the next period when the assets are commissioned. Over the longer term, the volume of these in-progress projects claimed at the start of a period should roughly balance those which carry over at the end.

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

We acknowledge that companies should have greater confidence in setting baseline outputs than in RIIO-1 due to the shorter price control period and improved understanding of asset deterioration and network risk facilitated by the NOMS methodology. However, the RIIO-2 proposal suggests a different approach to dealing with deviation of delivery from targets and does not appropriately fund or encourage efficient delivery.

Assets can deteriorate in unexpected ways and licensees need to have the ability to make the right asset management decisions and have their efficient costs funded. As raised in different NARMS working groups, the proposed approach introduces a perverse incentive to avoid delivery of justified additional interventions, when this represents the best outcome for customers.

We strongly believe that well justified over-delivery should be funded on the same basis as the mechanism for the business plan. This is to ensure companies are consistently incentivised to carry out effective asset management and to adapt to changing network risk. Experience shows that there are occasions when non-delivery of agreed works is either in consumer interests or is prevented by circumstances outside the control of the network owner. In these circumstances, under-delivery is justified and should not be penalised.

In regards to the proposal to penalise unjustified under delivery by an amount equivalent to the risk benefit not delivered, is unclear, and could potentially lead to a disproportionate penalty. Different activities on different assets can have a wide range of intervention cost and risk benefit through time. SPEN has been consistently accurate in its business plan forecasting. The proposed approach could be particularly disproportionate if this penalty were to be heavily based on the benefit not delivered over the longer term. We would welcome the opportunity to work further on this matter with Ofgem and the other companies.

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

Clarity is required on how projects which interact between load and non-load are reported in terms of outputs and cost categories in the business plan data tables.

There may be some projects where a co-ordinated approach to a load and non-load need case is the most appropriate solution. For those cases, we believe an uncertainty mechanism should be put in place to deal with possible changes in the load need case during the price control period and adjust the allowance accordingly. This enables projects to still be delivered in an efficient way and licensees are not exposed to risks outside their control.

Conversely, it should be noted that the differences in lead asset categories within the same sector will lead to different assessment methodologies and potentially funding mechanisms being employed for the same investment drivers, but with different output measures being used to measure the relative success or not. If it is necessary to use different assessment methodologies or funding mechanisms then the outputs used to assess these investments should be equitable and equally challenging. For this reason, the ED sector is currently working toward alignment of the asset categories covered by NARM ahead of the RIIO-ED2 proposals.

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

High value projects with significant uncertainty in their delivery timescales could have a large impact on the defined outputs, we therefore welcome the opportunity to ring-fence those with separate funding and PCDs.

Also, projects driven by legislative changes, or HSE commitments would fit well into this category.

Workforce Resilience Question

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

<u>Inclusion of Workforce Resilience</u>

SP Energy Networks are pleased to note the inclusion of Workforce Resilience in the Sector Methodology Papers for consultation. We fully support the requirement to explicitly set out our proposals to maintain a resilient and diverse workforce in RIIO2. We believe that these should be set out within the Business plans, as it is a key enabler to the delivery of the wider Business plan.

To enable a sustainable, resilient workforce within the current labour market requires ongoing levels of investment in Trainees, ongoing skills development of existing staff and development of new skills for the industry. We believe to achieve this workforce resilience; these plans must be explicitly set out in the Business plans with appropriate funding and measures to demonstrate delivery.

It is also important for the supply chain to have confidence in the support for workforce resilience, as the skills requirements reach across the industry and not just within the utility companies. A perceived lack of support risks unintended consequences on contractor risk pricing and investor sector attractiveness.

Each company faces a unique set of challenges from a combination of local market or geographical pressures and internal challenges like existing staff age profile. If the detailed challenges, strategy and plans are not included in the business plans, there is a danger that these are not considered within the context of the business plans and a core enabler is removed. Without a suitably skilled, sustainable workforce, the business plans cannot be delivered.

<u>Known Workforce Challenges and Extraneous Factors</u>

There have been many changing factors in the work place environment and society that have impacted on previous predictions around attrition. Within SP Energy Networks, and in particular the SP Transmission Business, we have a wide diversity of international employees from both the EU and beyond. This is particularly pronounced within the Projects division. This diversity brings great benefit in diversity of thought, skills and improved availability of resource, however, the ongoing impact of Brexit may increase the risk of attrition due to the existing diverse nature of our workforce.

Following the re-integration of the former Iberdrola Engineering and Construction (IEC) Business back into SP Energy Networks during 2018 our strategy for a Project Delivery Disaggregated Model has the advantages of improved continuity, control and visibility of employees who would be otherwise in a ‘tier one’ contractors organisation. However, this model does expose the company to higher levels of attrition more comparable with external construction organisations, as opposed to a utility.

To offset the risk associated with a purely external recruitment strategy and to develop a diversity that reflects the communities we serve, we apply a blended approach to Technical skills. Our strategy of “Grow our own” for core craft and operational skills, recruited from within our licence areas is complemented by external recruitment of specialist and project skills.

The age profile of our staff is not linear and we have a significant number of staff at or approaching pensionable age. Greater freedom with pension funds introduced recently have seen a higher than expected number of employees leaving on or soon after 55 years of age, particularly for staff who have long service with defined benefit pension funds.

For other staff, we have also observed a change in behaviours over recent years with new employees more likely to be mobile, trying out several roles and companies unlike in the past where the vast majority of new employees saw the company as an employer for life.

We are also seeing a change in the traditional skills required by employees working with a Transmission business. Changes in technology, for example series compensation, active load management schemes, substation digitalisation and protection and control developments have changed the skills mix required.

Current Commitments and Utility-wide Collaboration

We are extremely active within the wider industry skills arena, working collaboratively through the Energy & Utility Skills Group, Energy & Utilities Skills Partnership, Skills Development Scotland, the IET Power Academy and others to promote the industry, support STEM activities and ensure efficient, collaborative development of industry critical skills.

We see workforce resilience as one of the specific areas where cross industry collaboration clearly works to the consumer benefit. However, we are mindful of our wider competition law obligations and look forward to working with Ofgem, as competition enforcer, to ensure that we always meet those obligations, but collaborate in those specific instances, such as workforce resilience, where it is possible and clearly to the consumers’ benefit.

Timescales

We welcome the view from Ofgem that workforce planning is a long term commitment and that the strategy should include not only the RIIO2 period but a period beyond that. We already undertake workforce planning over an extended period and it is critical to be able to continue that to ensure a workforce that not only delivers now to our customer expectations but also for our customers in the future.

For a strategy with a core component based on apprenticeship, higher skills apprenticeships, engineering and Graduate development, it is essential that a long term view is employed. The plan must take into consideration ‘time to effectiveness’, i.e. the time taken from recruitment for each role to be effective in the role. Some specialist roles for example ‘Senior Authorised Persons’ or ‘Protection and Control Engineers’ can take many years to train new employees, therefore justifying recruitment and training ahead of the predicted loss.

Measures

We understand and support Ofgem's desire to have measures that support the delivery of workforce resilience plans while still providing the ability to make decisions in real time to optimise resourcing. We are continuing to work with the task and finish group to develop initial ideas on this area. We believe that appropriate measures could be incorporated in the Sustainability Scorecard within Social Performance and be further supported by a Performance Report.

In terms of milestones and measures to demonstrate an effective sustainable workforce strategy it would be prudent to monitor not only levels of resourcing against plan, but the effectiveness and accuracy of the forecast and plan, providing a mechanism to recognise unforeseen extraneous influences.

Our current policy and ongoing intention is to monitor movement dynamically, providing a mechanism to react quickly to major changes with a full review in detail annually, adjusting our future plans in line with any amended view on attrition and skill gaps.

Physical security questions

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

The scope of costs that fall under the PSUP does not reflect the actual works associated with PSUP. The understanding that we take from the consultation is that only CNI mandated works are included within the existing scope of costs. The "business as usual" aspect of PSUP such as, but not limited to, fencing, security systems and fire systems are not included in the scope of costs associated with the existing PSUP scope and, as such, should be considered for inclusion in the scope.

We agree that the works described are appropriate for classification as physical security, however, we do not think this definition is adequate to account for the range of physical security related activities network operators need to undertake. We are fully supportive of the PSUP programme and work closely with BEIS on this matter but the PSUP programme only extends to infrastructure designated as CNI. There is a significant footprint of infrastructure with a lower designation that must be kept secure from interference, vandalism and theft. Proportionate, risk assessed investment in physical measures, as well as technological detection and a deterrent, is necessary to prevent unauthorised access and safeguard the infrastructure.

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

We agree with the ex-ante allowance approach for PSUP works, where mandated by Government at the time the price control is set. As noted in the response to CSQ28, we believe that an ex-ante allowance approach for necessary non-PSUP physical security works is also appropriate.

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

Recognising the nature of PSUP works, we do not consider a reopener to be the most appropriate mechanism to deal with costs associated with, within period changes, to these government mandated works.

We consider a revenue driver mechanism to be more appropriate than a reopener mechanism to accommodate within period changes to PSUP works. The reasoning for this proposal is that the reopener mechanism is based on a TOTEX set level of reopener trigger, which these schemes, due to their volume and financial value, will not approach to allow the process of reopening. The costs of the works are known with sufficient certainty to support this approach.

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

SPEN agrees there is a requirement for flexibility within the price control mechanism to accommodate within period changes. However, we would suggest a volume driver mechanism is more appropriate than a reopener mechanism.

Notwithstanding the above, should a reopener mechanism be employed, SPEN would propose two reopener windows with the RIIO-T2 Price Control period. The first we would propose in 2022, one year into the RIIO-T2 Price Control period. This would be three years after the original RIIO-T2 business plan submission, and would provide an opportunity to review and reflect any changes to mandated works in the interim. The second reopener we would propose for 2024, mid-way through the RIIO-T2 Price Control Period, which may also align with initial discussions for the RIIO-T3 Price Control period.

More generally, wherever re-openers are used, it is an essential part of the regulatory framework that they are clearly defined and targeted. General or open ended re-openers can create investor uncertainty, which only increases long term costs to consumers.

<u>Cyber resilience questions</u>

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

The scope of costs that fall under the Cyber Resilience does not reflect the actual works associated with Cyber Resilience. While we agree with area (1) NIS regulation implementation, we consider that the wording for (2) should be "business as usual to maintain the current levels of cyber resilience". These "business as usual activities" are activities which, in the main, are yet to be determined and could change with frequently. All additional activities that we see as being required to be above the current running of Cyber Resilience and delivery of the NIS Directive, should be identified, and separately costed as business table lines.

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

Yes, we agree with this as a fair approach. We feel that this is an appropriate mechanism for the funding of Cyber Resilience. As the nature of Cyber resilience changes, this means that the requirements will constantly have to be reviewed and scopes changed to match. This is appropriate with a re-opener mechanism in place as well.

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

Yes, given the nature of Cyber Resilience and its ever changing position, we agree that a reopener is an appropriate mechanism to ensure an effective delivery of Cyber Resilience given the degree of uncertainty over scope and costs.

However we suggest that the reopener mechanism be based on a percentage of the allowed costs in this category as opposed to at the overall TOTEX level as this is more appropriate for this activity.

Managing uncertainty

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

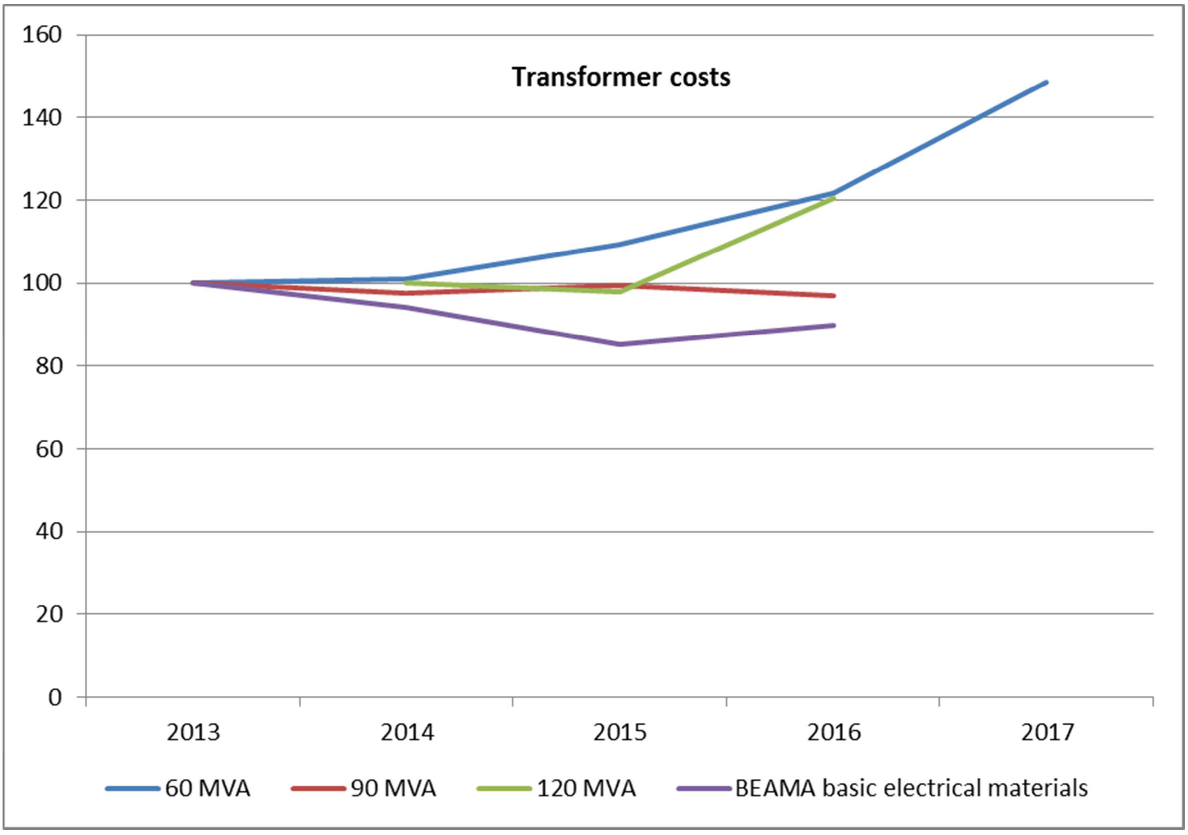
It is our view that the costs of inputs faced by companies in the energy networks sector do change at a rate different than that of economy-wide inflation. As such, these need to be adjusted by an appropriate measure to reflect input cost and price growth for each expenditure category. We would be happy to support Ofgem in further work to help ensure that its ultimate approach to real price effects recognises the challenges of ex-ante allowances, whilst respecting the evidence that economy-wide inflation is not a reasonable measure.

We have started to consider what alternative approaches might better reflect the true real price effects. Historical analysis of the outturn growth in the official input price indices, used to proxy the TOs input costs in RIIO-T1, has shown that input price growth has substantially differed from inflation growth with no consistent relationship between the two – whether measured against RPI or CPIH. Along with the increased volatility in these indices since the 2008 financial crisis, accurately forecasting input price trends has proved difficult due to their unreliability.

Our conclusions from research in this area over recent years is the common indices being utilised for forecasting RPEs are not sufficiently correlated to our specialised Transmission costs, leading to our actual experience being irreconcilable to indices. Further, we believe that to pursue RPE indexation, there is a need for development of statistically robust indices which are more closely related to electricity Transmission. An option would be to canvas statistical providers to collect more relevant data from the Electricity Transmission industry and use this to develop more appropriate indices. In addition more weight could be given to Transmission companies' procurement experience.

For SPT, the major contributions to Real Price Effects (RPEs) arise from materials (Capex) and contract labour.

Most commentators rely on BEAMA's "basic electrical materials" which recently has indicated a significant fall in costs. However, our analysis of the cost of the most frequently purchased transformers, by contrast, shows significant rises in recent years (see chart below). However, as we purchase some types of transformers infrequently, it is not possible to derive annual rates of change in costs for these. Nevertheless, the overall conclusion is that BEAMA's "basic electrical materials" is not reflective of our purchases of major items of capital expenditure.



As regards labour costs, for specialist engineers in industry, our experience is that supply is limited. However, the BEAMA electrical labour cost index would have presented a real input price decrease of 4% for specialist labour, for the period 2010/11 to 2017/18. This leads us to the conclusion that the labour indices may reflect lower skill levels, such as electricians, rather than, for example, Senior Commissioning Engineers, for which there is unprecedented demand.

In our experience, the usual proprietary industry cost and price indices do not reflect our own experience. Identifying, and testing, relevant and closely correlated indices, is essential if a mechanistic approach is to be adopted.

Future costs are expected to increase further, as the prolonged depreciation of sterling leads to rising costs of imported goods and services. We currently face demands for around a 15% increase in the sterling price of imported goods. Furthermore, following exit from the EU, there is the risk of the imposition of tariffs on imported goods, should the UK leave the EU without a future trading agreement with the EU. Nevertheless, the outcome of the Brexit negotiations is unknown, at this stage.

Following the submission of business plan data, Ofgem should work alongside energy network companies and statistical experts through an industry working group on developing more appropriate indices. Indices that are representative of the actual cost base of the network companies and are correlated with the actual input costs and prices faced by network companies (but which are not directly influenced by their own activities and decisions, which could lead to an endogeneity problem).

CSQ36. Do you agree with our initial views to retain notional cost structures in RIIO-2, where this is an option? & CSQ37. Do you agree with our initial views to update allowances for RPEs annually and to include a forecast of RPEs in allowances? Do you have any other comments on the implementations of RPE indexation?

Appropriate consideration needs to be taken on whether an indexation approach provides the most optimal outcome for both consumers and network companies. These would include the considerations of: whether the balance of risk allocation for input price changes between network companies and consumers is optimal; whether it provides for intergenerational equity; practicality issues of implementing an indexation approach; impact of the switch to CPIH; whether increased volatility in revenues and customer charges with an indexation approach can be smoothed (e.g. setting RPE index allowance to a longer moving average); and whether Ofgem can identify indices that are closely related to TOs costs and can guarantee both the data quality and continued availability of these third-party indices through to the end of RIIO-T2.

A methodology for RPE indexation will also need to take into account the different process for setting allowances for Strategic Wider Works Projects, which were set at different times. Also, specific projects, such as the Eastern HVDC link, will comprise unique sets of materials, equipment and installation requirements, such as sub-sea installation and work in a marine environment, which do not reflect our normal operations.

Additionally, it is essential that forecast Totex allowances are appropriately adjusted for real price effects, relative to CPIH, to ensure nominal costs will be recovered.

We believe work in developing an appropriate approach to RPEs for RIIO-2 price controls should be taken forward through an industry working group, building on any lessons learned from RIIO-1, which we would be happy to contribute to. Such a work programme would allow for a more complete assessment of the pros and cons of the indexation of RPEs and more detailed analysis of the design and construction of the index (including identifying the most appropriate set of cost indices to use) and evaluation of its impact. This would follow the submission of our RIIO-T2 business plan, in which we will address which cost areas we believe a RPE allowance would be appropriate and what mechanisms applied would be most appropriate.

Ongoing efficiency questions

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

We agree with this proposal given the regulatory precedent to use the EU KLEMS dataset to measure productivity in the UK. We would also support the use of other robust datasets in order to measure productivity in each sector individually.

Managing the risk of asset stranding questions

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

We agree with Ofgem that it is not appropriate to include a utilisation incentive. Utilisation levels on the electricity network are extremely hard to establish and partly out with the control of the TO. Ofgem identify many of the other measures that are in place, in section 7.23 which incentivises companies to invest appropriately

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

The desire to invest ahead of need is driven by customers and stakeholders who wish to connect to the network and cite the timing of connections being available as one of the key barriers. Network operators' pressure to invest in advance of need is on the back of increasing pressure from customers and to deliver a more optimal approach than is currently allowed. We agree with the principle of a mechanism to allow networks to be developed in a more timely manner, but the current proposal passes much of the risk onto network operators, despite this need being driven by customers.

In DPCR5, the Distributed Generation revenue driver mechanism was established that provided network operators with an allowance for incremental capacity, that they constructed to help facilitate further generation, and acted as a simple means of allowing and rewarding companies to efficiently build capacity, ahead of need. We would welcome the re-introduction of such a mechanism in RIIO-2 which was successfully used by SPD and SPM to create more network capacity, allowing further generation to connect earlier to the network, thus accelerating the low carbon transition.

An approach of considering societal regret costs, of not investing, may be an option for considering anticipatory investment. In particular, when seeking to be an enabler of government policy, which requires different facilities and perhaps driving changes across society. An example of this would be similar to the value of lost load, which could provide a metric which network operators can use to justify additional investment on the basis of the lost opportunity for consumers.

We have noted from our extensive experience of connecting significant volumes of renewable generation, that once assets are constructed and capacity is available, the demand often follows at ever higher levels than had been initially forecast. Such experience should be borne in mind when Ofgem considers the actual risk involved in allowing for anticipatory spend, in particular circumstances.

We welcome the proposal to establish a group similar to the Electricity Networks Strategy Group (ENSG) which allows strategic issues to be considered. Assuming an appropriate membership, such a forum would be a constructive approach to considering strategic network issues which can be difficult to consider as part of a price review, as they may be longer term in nature or enablers to future changes, which would not normally be considered in business plans. One area of focus we would suggest for this group is Black Start requirements. We are strongly of the view that a longer term, strategic view is required, encompassing not only network requirements but also market arrangements. This group would be the appropriate place for such discussions.

Whilst we welcome the proposal to establish this group, we are unclear as to whether this group is expected to have any role in deciding what anticipatory investment is required. It must be recognised that the role of the network operator to deliver agreed anticipatory investment decisions, would need to be clearly defined. Such proposals could not be forced upon the network operators, against their will, given the greater risk involved in this approach.

Further detailed thinking and discussions are also required on how anticipatory spend would be justified, assessed and then measured to ensure consumer value was delivered. The time period over which any anticipatory investment pays off, will be of particular relevance in these considerations. Whilst we consider that Figure three provides a good illustration of the economic considerations, the associated time period and approach of measuring success needs further discussion and consideration. Therefore, a forum such as the proposed ENSG, would also allow for cross sector/whole system approaches to also be actively considered in the round, where strategic anticipatory investment would normally be much harder to determine and coordinate.

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

Most strategic projects are driven by customer need, in particular, by generation customers. We have a number of sites where we can only invest, once customers have committed. Even at these sites, we get significant feedback that if additional capacity was to be made available, generation would actively be connecting to the system. It is the time taken for a connection which prevents the customer committing. We are finding that in many instances, it is the length of time to connect which makes projects unfeasible, rather than the cost of the projects. We would therefore suggest that an approach, where these customers share the risk, rather than the network operator carrying this risk, needs to be considered. An example of this could be the SHET-T proposed Orkney sub-sea link. If the Network operator has the confidence that the additional capacity will be utilised and properly remunerated, they can build it as they consider most appropriate.

Anticipatory investment may also include constructing greater network capacity than is currently required, to facilitate future connections as well as standalone investment. There could also be a range of other consumer benefits of anticipatory investment in over-sizing assets, such as reduced losses and faster facilitation of new demand and generation connections that would not offer a benefit directly to the network operator. Again, as outlined in response to the question above, Ofgem needs to work with industry players to consider how the success of such projects would be evaluated and over what time period.

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

Risk-sharing approaches need to be considered in the context of connecting customers who may benefit from anticipatory investment, consumers who will fund a large part of the works and network operators who undertake the works. There are a number of mechanisms already in place such as securities that generation customers place, which minimise the risk to consumers. These would all interact with this proposed approach and Ofgem should consider such wider, or incidental, effects before a decision is made.

We would also like clarity on the use of the 'high-value' terminology. There are likely to be many lower value opportunities that could also present significant benefits to customers that cannot be ignored.

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

Further consideration is needed on Ofgem's requirement for project justification, because at present, the high hurdle makes it challenging for these projects to be progressed. The reason why some of these projects may not be progressed in business as usual, could be as a result of the current regulatory approach, rather than companies withholding information.

We think further discussion is required as to how such a mechanism could be established to ensure appropriate risk sharing arrangements, ensuring value for money and unlocking the wider benefits that anticipatory investment may offer.

Driving innovation and efficiency through competition

Innovation questions

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

We agree that network companies need to innovate to remain sustainable, given the fast paced changes in the energy landscape. We believe innovation is the key to resolving our network challenges. As an industry, we have embraced innovation as we know what faces us cannot be solved by doing things the same way we did a decade ago. We have evolved our business practices, asset management techniques and have invested in the deployment of new materials and technologies within our network area in RIIO-1. This kind of innovation, that we call core or incremental innovation, has been delivered in the price control without use of any additional innovation funding. In reaching its RIIO-2 decisions, we think it is important that Ofgem performs cross checks to ensure that it does not inadvertently drive the industry to be overly cautious, e.g. by weakening the incentive to innovate and try new ways of doing things which will be to the consumers' benefit.

Our business expertise and knowledge of the network has allowed to us to keep in pace with the dramatic changes in Scotland's transmission and distribution networks. The closure of the last coal-fired power station and rapid increase in wind, solar and biomass generation, connected to our network, has posed some serious challenges in maintaining system security and stability in RIIO-1. We mitigated these risks and improved boundary transfers to England through the deployment of series compensation technology, establishment of the Western HVDC link and through various smart network and load management schemes, such as active network management (ANM). All of these are examples of SPEN taking the lead in deploying innovative solutions on its network. The innovation delivered through business as usual has also changed our business processes and enhanced our internal skill-sets. Our business plan for RIIO-T2 and RIIO-ED2 will further emphasise our innovative ambitions.

The type of innovation we are able to deliver through business as usual depends on case by case costs vs risks vs benefits analysis. Any technology or solution with unproven benefits, without proper standards and specification definitions, less understanding of the health and safety risks, lack of supplier base and/or lack of internal skill-set to design, delivering and maintaining such a solution is perceived to be of higher risk, and without a small scale trial, cannot be delivered through business as usual processes. The transition of proven innovation to business as usual also has an implementation cost for the business. The roll-out of proven innovation can result in benefits which largely accrue to 3rd parties, other network owners, operators and/or environmental benefits, which are currently not incentivised through TOTEX. The financial benefits that can be incentivised through TOTEX, in some cases, will only be realised in future price controls as there is currently no incentive to accelerate the roll-out of such innovation. In these cases, the implementation cost in the current price control might be unjustifiable for the network licensee, unless otherwise incentivised by the regulator.

We are currently also penalised for non-delivery in our price control periods. In order to encourage more innovation through business-as-usual, the regulator can make provisions to reward innovative business plans and provide incentives, such as the sharing of benefits generated through innovation within the price control period. Another option will be for the regulator to take a view on the perceived risks through trials of unproven innovative solutions and simplifying the criteria for performance measurement, for such price control deliverables.

Our RIIO-T2 innovation strategy focuses on building more innovation ability within the business, enhanced planning of the innovation portfolio and minimising the risk of transitioning innovation to business as usual. We agree that SPEN should be accountable for efficiently utilising innovation funding and delivering benefits to GB customers. We will therefore continue to evolve our internal processes and enhance our skillset to do so.

We will classify our innovation portfolio for RIIO-T2 into three categories of core, incremental (adjacent) and transformational innovation. Our RIIO-T2 business plan and innovation strategy will demonstrate that we are a leading innovation company. It will also demonstrate that we have adopted and will roll-out, where applicable, successful innovation trials from RIIO-T1 funded through the network innovation allowance (NIA) and network innovation competition (NIC). Innovation within our business plan will demonstrate our commitment to deliver core and, where applicable, incremental innovation through business as usual and use dedicated innovation funding to meet longer term challenges, transformational innovation and where the benefits mainly accrue to 3rd parties. Our approach to innovation as business as usual is that of fulfilling our licence obligation to maintain a an efficient and economical transmission system and managing the risks of the introduction of a new technology to that reliability. We agree with Ofgem that any allowed funding for BAU innovation which is not subsequently rolled out should be recovered as part of the close-out for RIIO-2.

It is vital that any decision Ofgem takes on innovation recognises the important balance that must be struck between the need for us to meet our competition law duties and the consumer benefits, specific, targeted, collaboration can bring. There is a risk of decreasing collaboration amongst network companies if innovative solutions are trialled primarily through business as usual processes. New technologies and solutions, which are deployed for the first time, do generate considerable amounts of knowledge and experience and it is in the consumer interests that network owners and operators to share this knowledge to drive efficiencies. This allows us to better drive the market and suppliers to create GB specific solutions. If innovation is only delivered through business as usual processes, there will be less opportunity for collaboration and knowledge sharing. It is important to maintain the right balance in the network owner's innovation portfolio between innovation delivered through business as usual and through dedicated innovation funding, which promotes collaboration and knowledge dissemination so that consumers benefit to the fullest extent possible from the specific instances where collaboration is appropriate.

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

We have successfully utilised the innovation roll-out mechanism (IRM) in RIIO-1 to facilitate more renewable generation and reduce environmental impact. The roll-out of High Temperature Low Sag (HTLS) conductor technology funded through IRM in 2015 in RIIO-T1 increases the total export capability from Coylton to the wider 275kV and 400kV network within SP Transmission and contributes 1.7GW by 2021 (and 2.1GW by 2023) of additional renewable generation to the GB system, representing 40% of the onshore wind generation in Scotland. The implementation of innovation through Integrated Network Constraint Management for Dumfries and Galloway funded through the IRM mechanism in 2017 project brought forward the roll-out of ANM across Dumfries and Galloway will enable more efficient utilisation of the energy network in the South of Scotland, reducing constraints to the existing wind farms connected in Dumfries and Galloway region. Our experience shows that there can be significant environmental and economic benefits achieved through roll-out of proven innovation as an alternate to planned network reinforcement.

The RIIO-2 price control is currently set to run for 5 years. Given the short price control period and provision for re-openers for critical issues, which will evolve quickly with changing nature of energy landscape and technological advances, we agree that IRM would be less effective in RIIO-2.

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

We are supportive of Ofgem's proposal of introducing a new network innovation funding pot, replacing the RIIO-1 network innovation competition (NIC) stimuli with a sharper focus on strategic energy system challenges. Energy system transition (EST) and the associated challenges have been the main drivers for innovation for SPEN in RIIO-1 along with improving efficiencies to benefit consumers. The EST challenges for RIIO-2 should be clearly defined through engagement with network companies and 3rd parties. These EST challenges definitions should be done in a collaborative and transparent manner, and should be flexible to changes when required and keeping pace with technological advancements, changes in policies and regulation. The ENA innovation strategy 2018 has already set a precedent in this direction defining themes of innovation based on EST challenges. The themes provide an overview of the funding utilisation across the EST challenges and the benefits generated through implementation of innovation in each category. Industry wide strategies defining the emerging energy system transition challenges such as the one from ENA should be encouraged and published on annual basis in RIIO-2, providing clear direction to network owners, operators and 3rd parties and aiding in creation of their own innovation portfolios.

We propose that Ofgem should put a mechanism in place to regularly perform gap analysis to modify these clusters and themes on an annual basis. This will minimise the risk of precluding any EST or technological advancement that requires innovation funding to be further addressed. It will also allow a review of a spread of innovation funding across the themes for innovation emerging from the EST challenges definition.

The risk with this approach however might be that the challenges are too specific and do not allow valuable transformational innovation to be taken forward that do not fall under the pre-defined categories. SPEN encourages Ofgem to retain the flexibility of funding projects where justified and demonstrate higher levels of collaboration and greater benefits to customers through flexible and discretionary funding schemes. Furthermore industry wide annual progress reports should be encouraged to keep track of progress of funded projects and provide an overview of roll-out of innovation projects that were successful in generating positive learning and delivered perceived benefits. This will ensure accountability and maintain transparency regarding how the EST challenges are addressed and the benefits generated through innovation throughout the price control period.

In addition to increasing focus on strategic energy system challenges we propose the following reforms for the new innovation funding mechanism based on our experience with NIC in RIIO-1

- Streamlining the NIC bid process by reducing the bid evaluation duration while increasing transparency and accountability for use of innovation funding to deliver benefits to GB customers
- Innovation based on clearly defined EST challenges and themes with a continuous review mechanism in place to ensure balanced innovation portfolio across themes and avoidance of repetition of themes to efficiently address energy system challenges
- Level of funding allocated to an EST challenge and theme should be made flexible depending on the long term benefits that can be generated and level of risk associated with the innovation proposed.
- Stage gated review and gap analysis of innovation incentives and projects to ensure projects are aligned to original objectives and are on track to deliver benefits. If deemed necessary, re-evaluation of project deliverables and gap analysis to ensure alignment of project themes in order to improve and accelerate integration of innovation projects to business as usual.
- Unified review and benefits tracking mechanism, in terms of impact assessment, application and implementation review. Avoidance of multiple publications of close down reports, project progress reports which is currently resource intensive and does not provide a whole picture of all innovation activities. We support development of industry wide strategies, application and implementation plan.

- Introduction of a benefits sharing mechanism to incentivise innovation within license areas and deliver tangible benefits to GB customers.
- Introduction of an independent governance board with representatives from each licensees, 3rd parties; government bodies and research institutes to ensure transparency and collaboration among the sectors and within the sector. The governance should support the definition the EST-related challenges. The governance board can also potentially streamline the reporting mechanism to Ofgem and will be responsible for the overall management of the innovation activities.
- Increased 3rd party engagement and collaboration across sectors where possible to ensure learning from one sector where applicable is adopted by other sectors addressing more common grounds of energy system transition.

Our proposal is to retain the NIC funding mechanism with some or all of the reforms listed above to account for deliverability, visibility of outcomes and improve ease of benefits tracking to further ensure roll-out of successful innovation and deliver benefits to GB customers. The level of innovation funding as proposed by Ofgem can be varied based on the stage of the innovation trial with higher level of funding available for actual network deployments and demonstrations and lower level of funding for early stage research and development (R&D) activities. There is a potential to provide direct access to 3rd parties for early stage R&D projects provided they partner with network companies to ensure the innovation remains focussed at addressing EST challenges and delivering benefits to GB customers.

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

We are supportive of both options of raising innovation funds either from Transmission Network Use of System (TNUoS) charges for network owners and through Balancing Services Use of System (BSUoS) charges for the electricity system operator (ESO) or raising all innovation funding from BSUoS charges. The BSUoS will be more volatile in future, however as highlighted by Ofgem most of the innovation projects undertaken by the ESO and network companies aim to generate benefits through balancing and settlement costs. This could be a direct measure of success of innovation projects and more transparent way of delivering benefits to GB customers. Ofgem could also take the view that as the benefits of many innovation projects related to balancing and settlement are still being rolled-out and will only generate benefits in future price controls and continue to raise innovation funds through TNUoS for RIIO-2.

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

Network innovation allowance (NIA) in RIIO-1 has encouraged increased engagement with 3rd parties, academia and has addressed critical system issues that required innovative system solutions and further research and development for deployment of suitable solutions. We urge Ofgem to retain NIA funding in RIIO-2 with necessary reforms and governance in place to ensure clear tracking of benefits and avoidance of duplication of efforts to continue the utilisation of this funding to address system issues generated through change in energy landscape.

We appreciate Ofgem's concerns that the sheer volume of NIA projects in RIIO-1 makes it difficult to track outcomes from individual projects and track learnings from other projects. Most importantly, it is difficult to track whether the findings from each project were utilised on the network to generate benefits. NIA funding in some cases funded lower Output Technology Readiness Level (TRL), research and development projects where the solution trialled was in a prototype design stage and/or confined to a limited supplier base. Such projects require further assessment, development into higher TRL solutions and sufficient supplier base for successful roll-out. The benefits generated from lower TRL and research and development type projects cannot always be measured through net quantitative benefits. A qualitative assessment (ref CSQ49) is required to assess the impact created by the project upon completion and the implementation plan put in place after completion to enable future roll-out. In many cases NIA projects in the past have informed future successful NIC projects. We agree with Ofgem that operation and maintenance type projects where NIA funding has been used to assess asset risks, or solve specific network problems typical to one substation in network licensee areas should be funded through business as usual in RIIO-2.

NIA funding in RIIO-1 has been a percentage of the licensee's regulatory price control allowance. We have concerns whether this is truly representative of the type of innovation required in the license areas. Energy system transition (EST) challenges are not scalable with the size of asset base owned by a network license. The number and type of challenges faced by the network companies is more related to the scale of change of generation and demand connected to their network, the growth of distributed energy resources and their ability to maintain security and stability of supply given the rapidly changing nature of the energy landscape. We propose that NIA funding in RIIO-2 should be more aligned to the level of risk posed to each network licensee through EST in their network areas. This will shift the focus of NIA funding from asset operation and maintenance to EST challenges. We also agree that there should be increased levels of collaboration and knowledge sharing among network companies for NIA projects in RIIO-2, building upon the successful collaboration established between network licensees in RIIO-1 through NIA and NIC.

In RIIO-1 in SPEN's NIA portfolio ~75% of the projects expenditure was allocated to 3rd parties involvement in various innovation projects. We aim to maintain our engagement with 3rd parties in RIIO-2 and encourage more 3rd party engagement through NIA especially for SMEs and academia. We suggest developing a feedback mechanism in order to provide more transparency regarding the kind and type of 3rd party engagement in NIA and other innovation projects to ensure that all viable 3rd party ideas and solutions with potential to aid with the energy system transition and with potential to deliver benefits to GB customers are taken forward through innovation incentives.

The risks of network companies having no NIA funding in RIIO-2 will be manifold, namely loss of collaboration between network owners, operators and 3rd parties on critical system challenge issues that requires trial of innovative solutions through small scale trials and research oriented projects. It will also adversely impact benefits that can be generated through innovation in future price controls beyond RIIO-2.

We are in complete agreement with Ofgem in addressing consumer vulnerability through NIA funded network-related innovation projects. We agree more innovation should be targeted towards empowering customers and prosumers to understand their role in the energy system transition. In fact there should be mandatory requirements to ensure network licensees have knowledge of their customer base and direct innovation towards the benefits of the consumers especially those vulnerable to economic fluctuations and changes in energy sector. Scottish Power's HALO project is an outstanding example of how innovation is being used to empower communities within Scotland.

We undertook a review of all NIA projects funded in RIIO-1 and identified the projects that can be considered for roll-out in RIIO-T2. Our review highlights that there has been considerable amount of learning generated through NIA particularly through projects where system studies and a quick trial of prototypes have mitigated risks on the network or deferred the risk of trial of a new innovative solution on the network by creating better understanding of the risks vs benefits case. Based on our review and experience with NIA we propose the types of projects to be funded through NIA funding in RIIO-2 in the table below.

Suggestions for types of projects to be funded through NIA in RIIO-2

Type of Project	Justification for funding through NIA
System wide planning and modelling addressing specific EST challenges	There is a considerable amount of system planning and modelling required understanding the behaviour of the power system in changing energy landscape especially with rise of more converter based generation. Studies will focus on future uncertainties in network behaviour. Such studies are required to predict network requirements beyond the price control and therefore would not be funded from BaU. Network companies have significant reliance on academia and research centres for such studies and as these studies are wide ranging involving different network elements and connected assets they should be funded through dedicated R&D funding. Ofgem have proposed that the replacement for NIC funding will be targeted at EST challenges. There needs to be a mechanism to prepare the groundwork for these large projects and de-risk them. Projects undertaken under NIA are ideally suited to that purpose.
Projects where the anticipated benefits are primarily to the customer or are societal benefits	Projects of these types do not have a TOTEX benefit and are therefore unlikely to be funded from BaU. Previous examples include active network management and real time thermal rating of cables which have accelerated the connection of, or increased capacity for renewable generation
Technology and solutions trials at lower TRL	The true evidence of the success of a new technology which is currently in prototype stage and/or not commercially available is achieved through a small scale network trial. These types of solutions are often brought forward by small medium enterprises (SMEs) and independent 3rd parties. Though the success rate of such trials might not be high. Given the risk profile of such projects they would not be funded through BaU. It is important to trial such solutions to avoid the risk of large scale investments in such solutions in future.
Projects related to enabling whole system approach	These projects cannot be undertaken under business as usual as the level of data sharing and collaboration required to enable whole system approach requires additional governance and intellectual property rights arrangements to be put in place for successful execution.
Projects focussed on defining new sector specific or cross-sector business models	The kind of projects which encourage creation of new sector specific and/or cross-sector business models require a huge amount of collaboration and stakeholder engagement in the definition phase and such projects can be potentially funded through NIA.
Projects encouraging customer engagement and empowering consumer base	Largely such projects will be funded through business as usual however in case of trial of new models and methods NIA funding will help incentivise network companies to further invest in such projects.

We concur with our peers, academia, 3rd parties and independent innovation and assessment bodies such as Energy Networks Association (ENA) and Energy Innovation Centre (EIC) that NIA funding should be continued in RIIO-2 with change in governance criteria to provide more transparency to stakeholders regarding utilisation of this funding through industry wide and network company specific innovation strategies.

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

We agree that there are reforms required to better track benefits from NIA projects in RIIO-2. The innovation review undertaken by ourselves of the NIA projects funded in RIIO-1 highlights that. NIA projects have created considerable amount of knowledge and learning for network companies and have concluded with further work planned and delivered through NIC and/or direct adoption in business as usual. The challenge has been more around projects with no clear outcomes and where no further work was planned after completion of the project. At present every network licensee independently tracks the outcomes and benefits generated through NIC and NIA projects, and there is opportunity to develop a unified and transparent benefits tracking methodology in future price control periods. We are in agreement with Ofgem's proposal to introduce more effective governance and a unified benefits tracking process around NIA projects in RIIO-2.

The work currently being undertaken by Baringa partners in collaboration with Energy Innovation Centre (EIC) and GB electricity and gas DNOs is evaluating methods to track and quantify benefits through NIA projects. This work can be adopted in RIIO-2 in the NIA governance process where the benefits generated from NIA trials with positive outcomes can be tracked over the price control periods. In order to manage uncertainty and risks associated with NIA projects a risk assessment can be performed at the beginning of each NIA project. The risk assessment should allow network licensees to only fund projects with acceptable risk scores and clearly defined mitigation measures through NIA funding. The cost benefits analysis (CBA) methodology developed through this work can establish a unified net benefits tracking mechanism for all network licensees. As proposed by Baringa, the CBA process can be repeated at various stages of the project and used to track benefits during the roll-out period.

We also recommend a comprehensive qualitative impact assessment and performance based benefits tracking methodology similar to that implemented by ENTSOE R&I framework to complement the CBA process developed by Baringa. This methodology can be used to review the impact of each NIA and potentially for NIC funded projects during and after completion of trial. The impact assessment and performance based benefits tracking procedures from ENTSOE's R&I framework roadmap proposes categories for benefits assessment at the end of the project, assessment of planned next steps and key performance indices (KPIs) to measure and track benefits of innovative projects. This process is complementary to the CBA process and acknowledges the inherent nature of innovation that not all projects will immediately result in roll-out after completion. It takes into account the implementation steps planned after completion of the project and qualitative impact created through the execution of project on different aspects of the business process in order to truly measure the success of a project with a holistic approach.

Impact Assessment

The impact assessment ensures the project created value through its execution and the funding used for the delivery of the project created measurable outputs that can be shared with other network owners. The following output measurement criteria can be used for NIA projects upon completion to assess the impact by the project during project delivery and at completion:

1. **Methodology** (includes methodology for designing new rules, scenarios)
2. **Software** (includes development and demonstration of simulation tools, decision-making support tools)
3. **Hardware** (includes development or demonstration of pieces of hardware)
4. **Database** (includes quantified scenarios, results of cost–benefit analyses, …)

5. **Policy, regulation, market** (includes business models, policy recommendations)
6. Other.

There is a greater need for tracking the next planned actions after completion of a NIA project as this will inform wider stakeholders regarding the status of the project and manage the expectations regarding possible roll-out of the innovation trialled through the NIA project. The types of next steps defined at the end of each innovation project can be categorised into:

- Further research
- Further development
- Demonstration
  - The projects categorised for further research, development and/or demonstration should be followed through a subsequent action plan to clearly highlight the next steps to be taken by the network licensee(s) to ensure the findings of the initial NIA project are successfully carried forward through a detailed action plan.
- Deployment
  - The sharing the knowledge gained and promoting the outcomes reached by NIA projects with a high potential of replicability or scalability and high potential to deliver benefits in the stage of deployment should be pursued to make the most of innovation investments. This final impact assessment of successful NIA projects can be based on
    1. Output Technology Readiness Level (TRL): achievements with output TRL higher than or equal to seven (system prototype demonstration in operational environment) that have been selected for business as usual roll-out;
    2. Achievements expected to be followed by deployment as the next step, with a target year to achieve roll-out of such projects with an implementation plan
    3. Analysis of the explanations given by project owners about the importance and urgency for the network licensees to implement the project achievements to allow for planning of funds for the implementation plan;
    4. The budget of the implementation plan.
- No further action
  - The network licensee(s) should clearly highlight why the NIA project resulted in undefined or no outcome that should be carried forward through an action and/or implementation plan. In this case, the benefits could be highlighted in terms of deferred investment if the project were to be pursued through business as usual.

<u>Benefits Tracking</u>

The key performance indicators (KPIs) for network owners innovation portfolio including NIA and NIC could be potentially based on two assessments aspects:

- Implementation Effectiveness KPI
- Expected Impact KPI

The 'Implementation Effectiveness' KPI could be a measurement of the percentage of completion of NIA project objectives defined in the project registration form. The methodology will include the evaluation of activities that are completed, ongoing, under proposal and not started.

The 'Expected Impact' KPIs consist of the following:

- **Overarching KPIs—**a limited set of network and system performance indicators,

- **Specific KPIs—**provide an overview of other specific technical parameters relevant for network operators and related to the different innovation clusters and themes
- **Project KPIs—**proposed by each innovation project that will stem from the innovation strategy and will listed in the implementation plans.

The Baringa and ENTSOE method for impact and benefit assessment can be directly adopted or modified for RIIO-2 to track benefits of NIA and NIC projects. The end objective being unified impact and benefits tracking system against which all NIA and NIC can be benchmarked and presented to wider stakeholders. Ofgem can also request for publication of yearly industry wide impact and benefits tracking report for its own assessment and to inform wider stakeholders regarding the benefits generated through NIA and NIC innovation stimuli in RIIO-2. The unified impact assessment and benefits tracking method will create transparency regarding utilisation of NIA funding by network licensees in RIIO-2.

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

We agree in principle with the proposals laid by Ofgem for distribution companies prior to commencement of RIIO-ED2. We agree the distribution network owners (DNOs) should be allowed to access the RIIO-1 NIC and NIA funding stimuli till commencement of RIIO-ED2 in 2023. We are also in agreement with the level of NIC funding set for DNOs between 2021 and 2023.

We appreciate and align with Ofgem's view to encourage and continue appropriate collaboration among DNOs and other network companies between 2021 and 2023. This implies DNOs should be allowed to engage in specific collaborations with transmission network owners in RIIO-2 price control from 2021 onwards through the innovation funding stimulus set for RIIO-2. Similarly network owners in RIIO-2 price control from 2021 should continue to collaborate with DNOs in NIA, NIC projects funded through RIIO-1 network funding stimulus. This will ensure that during the period between 2021 and 2023 network companies collaboration on strategic innovation activities is not affected by change in governance and funding regime. The leading network licensee should be responsible for the overall regulatory reporting and benefits tracking during the transition period between the price controls.

Competition questions

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

We support, and already use, competition where it delivers better outcomes for customers, provided that it is established in an effective, and legally robust, way.

We do not support the additional models that Ofgem has proposed for late and early competition. We do not see how they can be considered 'appropriate' for delivering wider benefits to consumers than the existing framework, given that the vast majority of work across our transmission and distribution businesses is already subject to market tendering and that significant problems remain with the additional late competition models Ofgem are proposing (detailed below).

We think it is important that Ofgem recognises the success of the Strategic Wider Works (SWW) framework, the current mechanism for delivering large scale projects, which has not been included as a potential late competition model, it allows specific opportunities for Ofgem to scrutinise and benchmark project costs and has already been proven successful in delivering large scale projects, whilst safeguarding consumers' interests.

In relation to the late competition models, we continue to hold the view that the SPV proposal is unlawful, unworkable and will not deliver the benefits for consumers. The inclusion of CATO in the suite of competition models is premature, given that the legislation does not currently exist to deliver the CATO framework, nor has Ofgem or BEIS given any indication as to when this legislation will be brought forward. With the legislative programme dominated by Brexit legislation for some time to come, we question whether the CATO framework will be in place in time for the RIIO-2 period. We also note that there is no mention of Ofgem's Competition Proxy Model (CPM) in the consultation document for the RIIO-2 framework. However, we understand it is Ofgem's intention to include CPM in the suite of RIIO-2 competition models. We would therefore suggest that in its decision to this consultation, Ofgem makes it explicitly clear which models it intends to include in RIIO-2. Ofgem must make sure that any decisions it makes in relation to CPM are consistent with those it makes for each of the TOs in RIIO-2, e.g. as to the level of gearing which it assumes.

Whilst, in principle, we would support early CATO models, we are unable to offer detailed comments on the early competition models proposed within the consultation document as it is unclear how they will work in practice, and if they are to apply to the transmission or distribution networks, or both. If Ofgem is committed to delivering early competition, we would strongly encourage Ofgem to develop a comprehensive policy detailing its proposed early competition models for both the transmission and distribution networks.

For the above reasons, we consider that the competition proposals for RIIO-2 are unclear within this consultation document. We also question whether the late competition models can be developed and embedded in sufficient time to coincide with the start of RIIO-2. This is a particular concern to us, given that:

a) there are substantive differences between the land and planning regimes in England and Scotland. We provide more details on these in response to CSQ52 below. In effect those differences mean that late competition, as currently imagined by Ofgem, would not be practical in Scotland.
b) the suggestion that TOs should set out in their business plans how, and to what expenditure, competition will apply during the RIIO-2 framework. We would urge further details from Ofgem on this, as a matter of priority, given the deadline for business plan submission.

Important differences between land and planning regimes in England and in Scotland

Ofgem's proposed models of late competition assume it is possible for a third party to finalise the design, construction, build and/or financing of network extensions or reinforcements **after** the relevant TO has obtained the necessary planning and other land consents.

We understand that this may be possible in England where a Development Consent Order ('DCO') is often used to create a transferable package of planning consents and land rights and avoids the need for certain further land rights, e.g. wayleaves, or easements, to be obtained and managed. The granting of DCOs operates to a fixed timetable and is usually completed in under 17 months.

However, that mechanism is not available in Scotland. There is no fixed period by which land rights and planning consents can be obtained. There are also legal and practical limits on the extent to which rights can be transferred.

Further examples of these particularly Scottish constraints, are set out below. In effect, they mean that any third party model of competition in Scotland can only be either:

a) an early one where the third party is licensed and therefore fully authorised and responsible for the project in advance of any consenting work being carried out (i.e. early CATO); or
b) a late one limited to the construction and/or maintenance of assets on behalf of the TO (i.e. existing SPEN procurement practices).

Constraint 1: DCOs are not available in Scotland.

The necessary land and planning consents must be obtained using separate statutory processes, which are expensive and can take many years to complete. Despite recent efforts to streamline arrangements, there are currently no firm proposals for reform. This means that there is a greater risk in Scotland that delay, caused by third party involvement, will affect a project's feasibility. Often external stakeholder focus is directed at construction methodologies and practices, for which the TO will not have responsibility e.g. under the SPV model.

Constraint 2: Consents are only provided on the basis of fully specified designs.

Planning consents and land rights are only given, once the full details of any proposed project have been set out. This often requires specification down to the metre for each individual pole on any line and a full Environmental Impact Assessment having been completed. Such advance specification will almost eliminate any scope for third party innovation in design or overall cost saving once consents and land rights have been obtained.

Constraint 3: Scottish Ministers' consent would be needed.

Scottish Ministers' have to consent to almost all above ground electric lines ('Section 37 consents'). Those consents cannot be transferred without the further approval of Scottish Ministers'. In giving their consent, Scottish Ministers' must take into account various factors, including the extent to which they are satisfied that the regulatory and statutory framework has been followed. For example, one of the principal factors in determining whether the original consent is granted by Scottish Ministers is compliance with the various duties set out in s9 and Schedule 9 of the Electricity Act 1989. Over recent years, we have provided Ofgem with various pieces of information and analysis on this particular point, and we would be happy to discuss it further.

Constraint 4: In most circumstances, wayleaves and other land rights can only be obtained through negotiation with each individual landowner.

Only the licensed TO can seek compulsory wayleaves. They are only available in certain circumstances and after efforts have been made to reach a voluntary agreement. This means that it is not possible to shortcut the process for obtaining the necessary land rights. It also means that, in practice, most wayleaves are voluntary and so subject to termination by the landowner. The potential involvement of an unknown third party is also likely to make the necessary negotiations more difficult, time consuming and expensive, as often external stakeholder focus is directed at construction methodologies and practices, for which the TO will not have responsibility e.g. under the SPV model. Even where a compulsory wayleave has been secured, it is not transferable to a third party.

Constraint 5: There is no sure fire way to fully protect a project from future landowners.

A wayleave is a personal agreement which is only enforceable against the specific landowner who enters into it. Whilst there are various ways a TO could try to secure enduring rights, e.g. by making separate contractual arrangements with the landowners, there is also case law which allows landowners to interdict third parties with whom they have no direct arrangements from entering or working on their land. This means that any third party would have to price the risk of future removal or re-negotiation of land rights into their bids.

Constraint 6: SPEN carefully manages its relationship with its land stakeholders.

There are a number of significant stakeholders in Scotland with whom SPEN has an enduring relationship, e.g. the Forestry Commission. A mutual trust has been built up over the course of years which is vital to SPEN to maintain. In our experience, the successful delivery of a project is, in very large part, dependant on positive working relationships being built and maintained. The involvement of a third party could have a negative impact on those relationships, either for a particular project or more generally, which would certainly increase the long term cost to consumers.

<u>Early and late competition models questions</u>

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

We consider that the criteria of projects which are new, separable and high value (>£100m) is sensible, given that this criteria is currently being used to identify projects eligible for late competition.

Is it Ofgem's intention that the figure of £100m will be used as criteria for competition for both transmission and distribution? We note that the Impact Assessment for competition only accounts for the £100m criterion.

We note the reference to 'native competition' made throughout the consultation document. We are also keen to understand how Ofgem intends to define native competition, and if the £100m threshold applies to all competition, including native competition.

We also think is it vital that the criteria are stable. Whilst their precise application may change, depending on the specific circumstances of any given project, it is essential that companies know what to plan for and that investors can have confidence that they understand the scope and risks of what they are investing in.

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

The draft Impact Assessment for late competition contains limited evidence. We do not consider that the findings of the draft Impact Assessment robustly make the case for introducing the late competition models, proposed by Ofgem.

As set out in our response, dated 9 November 2018[3], to the consultation on the Impact Assessment of delivering the Special Purpose Vehicle (SPV), we explained our reservations at the methodology that Ofgem and CEPA, their economic advisors, have used in the Impact Assessment. Our concerns remain true for the methodology used to calculate the costs and benefits for this Impact Assessment. We are also surprised that Ofgem has not chosen to undertake different Impact Assessments for the transmission, distribution and gas networks individually, given the different nature of each of these networks.

We note that even with the limited assessment which has been undertaken, the benefits have been measured against a £100m project. However, we also note that the scope of a project to be subject to competition is contingent on Ofgem's approach to 'bundling, splitting and repackaging.'[4] Ofgem's earlier guidance[5] on how this might be performed is pitched at a level of general principle and we note is due to be updated in May 2019. There is clearly a risk that splitting or repacking projects into bundles worth less than £100m could change the cost benefit analysis and so we assume that any bundle would have to be worth at least £100m, but we would be grateful if Ofgem could confirm the point.

Finally, we think it is unlikely to produce an overall net benefit if multiple different competition models were applied to one project. Doing so seems likely to introduce untenable complexity, additional cost and risk of delay to critical national infrastructure projects and so we would be grateful if Ofgem could confirm its policy in that regard.

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

As noted in response to CSQ53 above, we would expect the Impact Assessment to undertake different assessments for introducing late competition models across the electricity transmission, electricity distribution and gas networks. Individual assessments will accurately capture the different circumstances of each network.

[3] https://www.ofgem.gov.uk/system/files/docs/2018/12/spt_scottish_power_transmission.pdf
[4] RIIO-2 sector specific Methodology, Appendix 2, at p 145
[5] Extending competition in electricity transmission: Decision on criteria, pre-tender and conflict mitigation arrangements, Ofgem, 25 November 2016

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

We do not consider that the proposals put forward in the consultation document for early competition are appropriate for the transmission network. Should Ofgem decide to implement early competition models, we are of the opinion that different early competition models are required for transmission and distribution networks, particularly as DSO flexibility solutions will have a strong role to play across the distribution network.

Is it Ofgem's intention that early competition will primarily be used to identify potential ideas, as opposed to solutions? Or is it both? In which case, could there potentially be two tenders undertaken before an early network solution is agreed as the most effective approach for both network operators and consumers? Would further tenders then be run for implementation or delivery of the solutions?

We also question how willing parties will be to offer potential ideas in a tender exercise, where the eventual solution is to be determined by a follow-up exercise, which parties have no certainty of winning. Such an arrangement may therefore discourage parties from participating in the tender for ideas, in order to protect their Intellectual Property and innovative ideas, from other market players.

For early competition to be successful, Ofgem must establish a process that can identify, and effectively, deliver a competitive outcome. We ask Ofgem to set out how the early models proposed will deliver more effective competitive outcomes to consumers in comparison to the status quo, where network operators are responsible for delivering the most effective solutions for their networks and are benchmarked against each other as well as incentivised to deliver best value to consumers.

More generally, we note that competition must be effective. Amongst other things, this means that it must be very clear, for each stage in a project lifecycle, what is being subjected to competition, by whom and using what criteria. Without that clarity we see a risk that repeat competitions will increase overall risk, potential delays and cost for the industry, as well as creating market fatigue and damaging supply chains.

We would also urge Ofgem to set out its thinking on early competition in a comprehensive policy document, which includes suitable models for both transmission and distribution networks and a process for the operation of early competition models.

CSQ56. Are there other potential drawbacks of early competition?

The potential drawback with early competition, as identified in the consultation document, is that the most effective solution for the network may change, if solutions are chosen too early in the process. Clearly this will not be in the best interests of consumers or network operators especially if contracts have already been awarded and so costs will necessarily be incurred. It will also be important to ensure that speculative or poorly scoped competitions do not disincentive people from bringing forward ideas.

It is important that the early competition models continue to offer network operators as much flexibility as possible, so that if circumstances change or if new, more effective solutions arise, these can be adopted, delivering system security and the most cost effective outcome for consumers. As we explain below, we also see it as vital that any early competitions respect the different duties which Ofgem and the network companies have, as well as their technical knowledge and understanding.

As an operator of both transmission and distribution networks, we are familiar with working, and adapting to, the many changes which occur during the development of key projects. It will be important that the early competition models are designed in such a way as to cope with ongoing project changes, should a solution be adopted too soon in the development of a project or project circumstances change which renders the adopted solution no longer the most effective solution.

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

We are not aware of any existing examples. However our own experience has shown the benefits and cost savings which come from carefully designing procurements, for example, in the level of disaggregation and approach to smaller suppliers, as well as positively engaging with our supply chain. We are already sharing the benefit of this approach with our customers and would welcome the opportunity to discuss with Ofgem how we could build on the success to date.

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

In the absence of a clear policy framework for early competition models for transmission and distribution networks, we are not in a position to offer detailed comments on the advantages and disadvantages of the early competition models proposed.

As already mentioned, like Ofgem, we do consider that there is a particular risk with the early competition models in that network operators are 'locked in' to a solution at too early a stage, which may not be the most optimal and effective solution for the network, or consumers, in the longer term in particular as circumstances can change. There is real merit in retaining flexibility. Equally, there is a risk that 3rd party competitions could raise costs by creating further uncertainty in project delivery.

We note that similar risks have been managed in other sectors through detailed project and competition planning, including pre-tender market engagement and development of full project documents. For example, the competition for the Thames Tideway project achieved relatively low financing costs for the construction period. However, that competition was only run once the need was settled, the precise scope, licensing arrangements, project documents (including delivery and construction agreements) and government support package had been negotiated and put in place. That work took time but was an essential part of allowing the risks to be understood and effectively managed.

As noted above, given the potentially long lead in times for effective competitions, it is important that Ofgem set out a clear, comprehensive policy as soon as possible.

That policy should also recognise the risk that a more innovative, risky solution has greater potential for delay, with delays to strategic network infrastructure resulting in increased costs for consumers, for example, in constraint payments. We note in the recently published "Network Options Assessment 2018/19" report that the ESO accepts that investing in traditional reinforcement, at the right time, can lead to hundreds of millions of pounds in constraint cost savings to consumers. Looking across three different investment strategies, the ESO predicted savings of £220m-£460m[6] in constraint costs. Ofgem must therefore give detailed consideration to constraint cost savings as part of its cost benefit analysis work when considering early competition options as an alternative to traditional reinforcement, which will become an inevitable option in the short to medium term. This must be borne in mind by Ofgem as it considers the consumer costs and benefits for a particular network solution. Flexibility will be essential if early competition is going to be delivered cost effectively for consumers.

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

As mentioned above, we consider that there should be different early competition models for distribution and transmission networks, which could be reflected under the same competition criteria.

Given the potential for network operators being 'locked in' to a particular solution too early in the process, when there is still the potential for other options to be considered, we are supportive of the inclusion of "certainty of system need" to be included in the final criteria to ensure that consumers do not support early solutions to a network issue, which very quickly becomes outdated. It is also

[6] Network Options Assessment 2018/2019, p27
https://www.nationalgrideso.com/sites/eso/files/documents/Network%20Options%20Assessment%202018_19%20report.pdf

important that the time period over which costs and benefits are assessed is appropriate, given the potential for some solutions to simply ‘kick the can down the road’.

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

We recognise that competition is a powerful force, when used in a way which is both effective and fair. We agree that market participants must see the process as being fair and transparent and therefore have confidence in the outcome. We also agree that economies of scale and scope and technical proficiency are important factors in deciding who should take on what roles. However, for competition to be effective it must be designed in a way which respects the statutory framework and builds out from existing competitive markets. We suggest Ofgem considers the following distinction:

Competition for the market
Parliament has already decided that only Ofgem has the power to licence those who are to be given the rights and responsibilities over transmission or distribution activities. It has also made sure that those companies have access to the powers they need to properly develop and deliver networks, and to do so in a way which protects consumers. We therefore consider that only Ofgem can run and decide upon any competition model which decides who is allowed to engage in transmission or distribution activities (e.g. through an early CATO model).

Competition in the market
Parliament has also already decided that it is the licensee’s duty to ensure that the networks are developed and maintained in an efficient, co-ordinated and economical way (S.9 Electricity Act 1989). Therefore the licensee must remain in control of how that duty is discharged, e.g. by running competitions for the outsourcing or tendering of any activities.

This approach would also allow the licensee’s technical proficiency and the TO’s intricate knowledge of their own networks and local/regional circumstances to be fully utilised. It would help ensure that the long term design and operation requirements were properly considered.

We agree that the licensee can, indeed should, consider the views of others when developing and maintaining the network. We continue to support the ESO’s role in recommending possible network solutions, but recognise that the ESO can only properly make ‘recommendations’.

We note that this split of roles is similar to that used in other sectors. For example, in telecoms, Ofcom are responsible for running competitions for and awarding new spectrum licences. The split is recognised in various different ways in the legal framework for the water sector. Under the Specified Infrastructure Project (SIP) model, the Secretary of State is responsible for determining the scope of a project; the network licensee then runs the competition for the 3rd party provider of solutions which it needs to deliver on its obligations, with Ofwat then licencing the winning provider.

We think that Ofgem should be careful to avoid undermining the statutory framework and procurement obligations in order to address perceptions of bias. There are many different ways in which competitions can be run in a transparent and fair way. Indeed most network companies already do so because of their wider legal duties to observe procurement rules.

The role of the ESO
We do not consider that the ESO should play a role in running early and late competitions in RIIO-2. With its role in operating the GB Balancing Market, the ESO has a commercial interest in the development of non-asset and commercial solutions. This runs the risk of the ESO benefitting financially from decisions taken in running early and late competitions.

Whilst the consultation document makes reference to the role the ESO plays in the Network Options Assessment (NOA) report, it should be borne in mind that this report only makes recommendations following an economic assessment of when projects should be delivered. It is quite rightly, the responsibility of TOs, to propose and justify the large scale network reinforcements required across their own networks.

In addition, appointment of the ESO to perform Ofgem or the network company's statutory roles would inevitably lead to a duplication of work but could also undermine the legality of any effort to improve delivery.

Further, Ofgem would have to create new ways of exercising scrutiny over the ESO's work. The exercise of a decision making function would need to remain unaffected by the ESO's own view of whole system solutions and uninfluenced by any divergence of opinion the ESO may have had about the proposed project during the NOA process. An ESO run tender may also require sharing of sensitive information, beyond what is necessary or appropriate. Therefore, this would not be the most efficient or expedient way through which to progress needed infrastructure improvements.

Finally, however the various roles are scoped, it will be important to make sure they don't overlap. For example, Ofgem's statutory consultation to modify standard condition C27[7] (the Network Options Assessment process) envisages a role for the SO to make a recommendation so Ofgem can decide whether a project meets the criteria for competition Given the overlap, there is a clear need to ensure that Ofgem's competition policy is developed as a complete whole.

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

We would welcome a precise definition from Ofgem on 'native competition', which is referred to within the consultation document. Does it only apply to traditional procurement exercises undertaken by network operators or does it also relate to flexibility solutions, which are being increasingly used across our networks?

We would welcome clarification of this point at the earliest opportunity, given the suggestion that network operators should set out in their business plans how, and to what expenditure, competition will apply during the RIIO-2 framework. We would urge further details from Ofgem on this, as a matter of priority, given the deadline for business plan submission. With RIIO-2 draft business plans due to be submitted in the next few months, we would suggest that the RIIO-3 framework allows Ofgem a more realistic timeframe to develop any proposals around 'native competition', in the detail necessary to allow stakeholders the opportunity to offer constructive comments.

In relation to the Competition as a 'price finder' proposal, we would welcome further clarity on Ofgem's proposals. We assume that the intention is not to require market competitions where bids are used to simply change the allowance given to the TO. There would be no reason for 3rd party companies to participate in such 'shadow' competitions and it is unlikely that they would be compliant with network companies' statutory procurement obligations.

Scenarios should also be avoided whereby 'price finder' tenders are used by market players to attempt to influence, or change, a network operators' intended plans, to their own commercial advantage, due to unrealistic prices being submitted as part of the tender exercise.

Consideration must also be given to the fact that when the network operator does eventually run the 'actual' procurement exercise, the parties who participated in the earlier 'price finder' exercise, will have run a cost for the earlier 'price finder' exercise, and will simply look to recoup these costs, by adding them into their bidding price for the actual competitive tender.

We would argue that this complicated and risky approach is unnecessary as Ofgem already uses a form of 'price finder', in transmission, where it bench marks prices across the 3 TOs. This means that, in approving network companies' business plans, or specific projects, Ofgem already has access to extensive cost information. Network companies, such as ourselves, subsequently tender large parts of their work.

[7] https://www.ofgem.gov.uk/system/files/docs/2019/02/c27_cover_letter.pdf

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

We are strongly of the view that the current arrangement, with the use of totex being incentivised, is undoubtedly the best approach for driving efficient costs and consumer benefits, given that both the TOs and consumers aim to benefit from this successful incentive mechanism.

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

As per the above response, we remain strongly of the view that the current totex framework remains the best approach for driving efficient costs and delivering consumer benefits.

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

We do not support the ESO having a role in facilitating competition in the gas sectors. We consider that the ESO should continue to focus its resources on delivering its work programme across the electricity transmission and distribution sectors.

9. Simplifying Business plan assessment

Business plan and totex incentive questions

CSQ65. What are your views on our proposed approach to establishing a Business plan incentive? CSQ66. Under the blended sharing factor approach, should the scope of stage 2 evaluation of cost assessment be based on the entire totex or only on cost items that we consider we can baseline with high confidence? CSQ67. What should be the method for categorising cost forecast as High, Medium or Low? Are the indicative boundaries of 1.0 (High to Medium) and 1.04 (Medium to Low) appropriate?

This response covers questions 65 to 67. Essential to a regulatory incentive being effective are the properties of transparency, consistency and fairness. To achieve this for a complicated area like stage 2 evaluation of costs, a detailed methodology should be prepared setting out the cost assessment tools that Ofgem will apply.

It has long been acknowledged by Ofgem that they do not have perfect information. To recognise the complexity of the process the interpolation rule was devised which applied a 25% weighting on network owners forecasts and 75% to Ofgem’s assessment. We believe a greater tolerance needs to be applied to determining the categories proposed for the business plan incentive. A materiality range should be applied so as not to differentiate between companies within 2% of Ofgem’s view of costs. A level of accuracy of 0.49% of totex, which Appendix 3 may suggest, is too precise for such a complex forecast. It would seem unjust to exclude a company from the ‘Good’ or ‘Average’ category that was within a tolerance of Ofgem’s forecast considering all the components of totex.

We propose the range for ‘Good’ is X<=1.02, ‘Average’ 1.02> X < 1.06 and ‘Poor’ X >1.06.

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

Considering the success of the established business plan incentive in prompting good value for consumers we propose Ofgem should retain the option of awarding up to 2% of a company’s own totex in circumstance when more than one plan demonstrates good quality and value. The current proposal significantly reduces the strength of the incentive, and potentially companies’ ambition, by diluting the prospective reward value by the number of companies also achieving a set criteria.

Based on the Ofgem’s proposal, the incentives strength, particularly in the RIIO-ED2 price control, has the potential to be very low.

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

We agree with Ofgem's assessment of the IQI and that learnings can be made from RIIO-1. However we do not agree with Ofgem's proposal to remove the IQI in its entirety and we remain supportive of the option to retain the IQI mechanism for the totex incentive rate, enhanced to recognise the learnings from RIIO-1. A significant benefit of the IQI mechanism is the clear and appropriate relationship between efficiency and the totex sharing factor.

A predetermined matrix has the benefit of providing clarity and incentive to an ambitious company. It is essential that the scale, mechanism and means of assessment are present for the full incentive properties to be realised.

Any concern that the IQI alongside another upfront incentive may result in a duplication of rewards and penalties can be mitigated by only utilising the IQI for establishing the cost sharing factor. This has the benefit of avoiding the complexity of the blended sharing factor proposal.

The existing IQI matrix is calibrated to provide the maximum reward to companies should they bid in accordance with their actual forecast expenditure. A company spending less than their forecast will not have acted in a rational manner had it had all the information at the time of their initial bid. We therefore believe Ofgem's statement, in paragraph 9.28, "that we have not seen evidence the theoretical assumptions that are required in order to make the IQI effective are achievable in practise", is flawed. We believe there are isolated outcomes that are very unlikely to be repeated, that should not be interpreted as undermining the IQI matrix.

CSQ70 Do you have views on the effectiveness of the blended sharing factors approach and in particular the incentive it provides on companies to submit more rigorous totex submissions?& CSQ71. Do you agree with our assessment of the blended sharing factor in comparison to the Ofwat cost sharing mechanism? If not, please provide your reasons.

We do not think sufficient emphasis has been placed on dis-incentivising over ambitious or audacious totex forecasts. We believe the Ofwat proposals have the potential to encourage risky and undesirable management behaviours of under forecasting. The separation of sharing factor for overspends / underspends encourages risky speculative bidding.

CSQ72 Considering the blended sharing factor, what are your views on the factors (e.g. predictability, ability to effectively deal with uncertainty) or evidence that could be used to distinguish between costs that can be baselined with high confidence and other costs?& CSQ73. Do you have any views on the level of cost disaggregation we should apply to calculate the blended sharing factors approach on (regulatory reporting pack level or another level)?

We require further clarity from Ofgem on the proposed application of the blended sharing factor, particularly around the basis to be applied to determine which costs would be 'baseline' and 'non-forecastable' costs, before we could provide an informed response.

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

Ofgem's proposed business plan reward is consistent with our objectives and we believe in principle has good regulatory qualities including, ensuring stretching cost, and output forecasts, are submitted promoting a RIIO-2 settlement that is good value for money for consumers.

We believe it has been acknowledged that the RIIO-1 business plan incentive was an important catalyst that influenced the step change in the comprehensive nature of network operators business plans. In our view, one of the important benefits of RIIO is the proportionate feedback and reward depending on the quality of the business plan. If a business plan is well-justified, demonstrating appropriate stakeholder engagement with a clear strategy, then it is appropriate for an incentive mechanism to reward companies.

Considering the success of the established business plan incentive in prompting good value for consumers, we propose that Ofgem should retain the option of awarding up to 2% of a company's own totex in circumstance when more than one plan demonstrates good quality and value. The current proposal significantly reduces the strength of the incentive, and potentially companies' ambition, by diluting the prospective reward value by the number of companies also achieving a set criteria. This incentives strength, particularly in the RIIO-ED2 price control, has the potentially to be very low.

To date the new business plan incentive lacks detail and guidance on what criteria Ofgem will apply in their business plans assessment. The clear communication of the detailed assessment criteria is a prerequisite to ensuring the Network Operators are informed and the process is equitable.

We believe there would be benefit in reviewing Ofwat's approach to business plan guidance, which provided clarity well in advance of their submission date. In response to Ofgem's working groups we tailored an approach based on Ofwat's for RIIO-T2 and provided this to Ofgem for consideration. We are not opposed to an upfront penalty regime for companies that do not meet Ofgem's minimum requirements, however this is on the basis those requirements are clearly and unambiguously set out in the very near future.

Currently, with the information made available to date, the IQI mechanism is considerably easier to communicate than the business plan incentive or blended sharing factor proposal. For example, additional clarity needs to be provided in the consultation decision on the scoring mechanism that Ofgem refers to in paragraph 9.13 and the weight for each element it intends to utilise for the assessment of cost and qualitative elements of the business plan. Transparency and consistency are essential qualities of a regulatory incentive. How does Ofgem propose to communicate the basis of their assessment at each stage? How will Ofgem ensure consistency across Network Operator business plan assessments particularly in the more subjective qualitative elements? Will Ofgem consult on their assessment at each stage?

We are of the view the interpolation rule should be retained. It has long been acknowledged by Ofgem that they do not have perfect information and therefore applied a 25% weighting on network owners forecasts and 75% to their assessment in order to recognise the complexity of the process. The potential inequity of a price control is greater if the interpolation rule is not retained due to the greater potential for unintended differences in allowances between companies. In addition, this inequality would be further compounded under 'Anchoring Returns'.

We support the proposal to not include the business plan incentive within the scope of potential return adjustment mechanisms.

CSQ75 What views do you have on our assessment of the sharing factor ranges? & CSQ76 Are there any other factors that you think we should take into account in the design of sharing factors?

We do not support the blended sharing factor approach. We believe a direct relationship should be retained between the cost efficiency assessment and the efficiency incentive rate. Therefore neither can be assessed fully in isolation. We would support a stage 2 evaluation of cost assessment based on the entire totex as the overall cost forecast should be considered in the round.

In our view the blending approach has more inherent issues than the mechanism it is seeking to replace. The determination of costs to be considered baseline and the subsequent baseline categories introduces a new degree of complexity which will require consistency checks across price controls and sectors. Ensuring consistent and equitable application is an essential regulatory quality, however this will be very difficult to achieve across all NWOs. Inconsistent application of the categories or costs with similar properties will create the possibility of endless cost boundary debates and through inconsistent application unintentional inequality across companies and sectors.

A detailed methodology of this proposal incorporating category definitions and the criteria for weightings should be provided to meet good regulatory practice.

Blended sharing will dis-incentivise investment in initiatives (NPV +ve projects) in more established areas like non-load where the current incentive rate will be reduced through blending. This will have the effect of stifling cost reduction initiatives and potential future efficiencies for the customer. It will be very difficult to demonstrate NPV positive improvement projects, which are currently very tough to achieve when the sharing factor is reduced.

Additionally, under the totex sharing proposal the link is not as clear that more efficient forecasts will achieve a higher sharing factor. Companies are only incentivised to provide lower cost forecasts through the Business plan incentive but may not be granted an appropriate higher sharing factor for more efficient forecasts.

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

We do not have substantial data at a sector level, however from review of regional and national macroeconomic data we can see that ongoing efficiency has stalled in the economy. There is considerable comment on the reasons for this with commentators having referenced the recent recession. The deputy governor of the Bank of England has recently commented that the economy could be experiencing a similar lull as to when the steam era was over but the age of electricity was yet to begin, comparing this to the end of the current digital era boom and awaiting the next big technological breakthrough.

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

If so:

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

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

An adjusted sharing factor would introduce a further level of complexity to the price control process and arguably create greater risk to shareholders.

Shareholders will approve investment in initiatives during the price control based on analysis on which sharing factors will be a key input, for example NPV analysis of totex savings. The introduction of changing sharing factors will undermine investment confidence in initiatives.

The potential for significant movements in areas like generation connections or shared infrastructure load growth is possible. These areas will likely feature in the low confidence category as they are uncertain by their nature. It would seem unequitable for movements in low confidence areas to materially reduce the sharing factor for changes in circumstance, completely out-with the Network Owners control, and detrimentally impact the basis upon which investments in initiatives have been approved.

Fair returns and financeability

Cost of Debt questions

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

In our response to Ofgem's RIIO-2 Framework Consultation, we considered that it would be in consumers' interests to replace the current indexation approaches in RIIO-1 with a pass-through allowance for debt for energy network licensees in RIIO-2 (Option C) as this would remove any incentive to adopt short-term financing decisions and would ensure that consumers pay no more than the licensees' actual interest costs. Following Ofgem's removal of this option, for setting cost of debt allowances in RIIO-2 in their Framework Decision document, out of the remaining two cost of debt options for RIIO-2, we are supportive of Ofgem's retention of the full indexation approach (Option A) over the partial indexation approach (Option B).

We believe at this stage, that there is a benefit of consistency and predictability for investors and stakeholders, with the continuation of the RIIO framework's established indexation based methodology for the cost of debt. Our inclination of the full indexation approach (Option A) over Option B is, however, contingent on the mechanism being sufficiently calibrated to allow for the recovery of efficiently incurred debt costs. We outline our recommended suggestions for re-calibration in section FQ3.

We agree with Ofgem's decision to no longer consider the partial indexation option in its cost of debt methodology. The approach, which is comparable to that proposed by the CAA and Ofwat, would involve setting the allowance explicitly in two parts by adopting a fixed allowance for embedded debt plus indexing new debt raised during the price control, would not be in the best interest of consumers, compared to a re-calibrated indexation mechanism. Setting embedded debt costs on an ex ante basis, against an industry average which would involve Ofgem making a subjective decision on which averaging technique would be appropriate for the calculation of embedded debt costs for each sector, is going against Ofgem's principles that the debt allowance mechanism should be simple and transparent.

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

We agree with the removal of the proposal for debt under/outperformance sharing. The introduction of such a mechanism could prove unfavourable, in so far as, it would introduce further complexity to the price control framework and cause further uncertainty in forecasting returns. It would also impose additional resource pressures on Ofgem in order to accurately estimate and verify company debt cost performance annually.

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

We are supportive of the next steps outlined by Ofgem and welcome the willingness to continue assessing the options of re-calibrating the RIIO-1 indexation mechanisms, based on feedback and evidence submitted by network companies and other stakeholders. NERA's modelling of debt performance over RIIO-2 under each sector's existing mechanism shows that all sectors are expected to underperform the debt allowance.[8] These results emphasises the need for Ofgem to re-calibrate the allowance mechanism in order to address expected underperformance.

The reference benchmark index should be representative of the costs debt financing, exhibited by network companies. This is accomplished by selecting a benchmark index whose average remaining tenor matches the efficient tenor at issuance of network companies' debt. We believe that the RIIO-1 selected benchmark index (the iBoxx non-financial corporate 10Y+) meets this objective and should continue to be used as the basis for the setting the cost of debt allowance. The index is calculated with reference to more regulated utility bonds and better captures the debt profiles of network companies, as it has a remaining tenor which is approximate to the average tenor at issuance of network companies' debt, of around 20 years.

We propose an extension of the current index mechanism's trailing average period, in order to match the average remaining tenor of the bonds in the iBoxx A/BBB index. As the average tenor of issuance of energy network companies' debt is around 20 years, a move to a trailing average period of 20 years would therefore be the theoretically correct approach for the cost of debt indexation mechanism, as this would ensure that the index better reflects the longer term nature of network companies' debt. A move to a longer trailing average for RIIO-2 would provide companies with an allowance that is reflective of financing the cost of efficiently incurred long-term debt across the energy networks sectors, hence providing them with sufficient revenue to service their debt costs.

Ofgem sets out further modifications to the full indexation mechanism in para 2.24. The notion of the existence of the "halo effect" (i.e. that network companies have raised debt at rates less than the current iBoxx benchmark) has been previously justified on the back of unsound evidence. NERA's analysis[9] has shown that Ofgem's analysis of the halo effect at previous price controls (GD1/T1 and ED1), and CEPA's analysis in their February 2018 report both suffer from sample bias, which results in a failure to compare network debt issues and the benchmark iBoxx index, on a like-for-like basis. After correcting for factors such as rating, yields, tenor and the significantly cheaper utility ILD issued pre-2010, the historical halo can be shown to be near negligible, and recent network company bond issues showing an effect that is non-existent and perhaps evens negative. This in clear contrast to CEPA's estimated halo effect of 38 bps for nominal bonds.

Given that there is no evidence to support a halo effect, Ofgem should provide an explicit allowance for debt transaction, liquidity and cost-of-carry to compensate companies for these unavoidable transaction costs associated with raising debt financing. NERA's modelling for cost-of-carry and operational liquidity costs alone support the provision for an allowance in the range of 23-56bps.[10] Allowance for transaction and liquidity costs has also been supported by regulatory precedent.

Additionally, Ofgem need to be mindful of wedding the rating of the benchmark index to the prescribed financeability rating from the overall regulatory package. If the regulatory package is inconsistent with an A/BBB rating, then Ofgem should consider basing the notional cost of debt index on yields from BBB rated bonds only.

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

The immediate switch to CPIH indexation necessitates a change in Ofgem's approach for the derivation of the real cost of debt allowance from observed nominal yields. The two approaches advocated by Ofgem in the Finance Annex (paragraph 2.14) present technical issues that will require

[8] NERA (March 2018), "Cost of Debt at RIIO-2", a report for the ENA
[9] NERA (March 2018), "Cost of Debt at RIIO-2", a report for the ENA
[10] NERA (March 2018), "Cost of Debt at RIIO-2", a report for the ENA

further assessment by Ofgem and industry, to ensure the deflationary approach ensures the financeability of companies over RIIO-2, and NPV neutrality over the long term.

We do not agree with Ofgem's consistency reasoning for retaining the current RIIO-1 method of deflating the nominal iBoxx index, in deriving a real cost of debt allowance, through the use of break-even inflation. RPI Break-even inflation is a biased measure of expected inflation and habitually overstates expected inflation. This is mainly due to the excess demand for long-dated real gilts from obligations coming from institutions such as pension funds, but also due to the presence of the "inflation risk premium" which is priced in the yields of nominal gilts. The large historical differences between break-even inflation and outturn inflation risk leading to a situation over a regulatory period where network companies may not recover their nominal debt costs in any one year if the inflation component of the RAV return is not equal to the real allowed cost of debt. The need to adjust the RPI break-even inflation measure with an assumption on the RPI-CPI wedge, in order to derive a CPIH real allowance, could further exacerbate the issues with utilising break-even inflation. This option would therefore add further complexity into the derivation of a real allowance and variations between forecast and actual wedge, could introduce an uncontrollable cost for network companies which may increase cashflow volatility. Additionally, in adopting this approach Ofgem are choosing to retain the use of RPI within the price control, thus the switch to CPIH indexation would not be a clean one.

The use of an ex ante CPIH inflation assumption is likely to accentuate risk, due to the correlation between nominal debt costs and inflation. If the debt allowance is set based on an outturn nominal benchmark index and a fixed ex ante inflation assumption, the real allowance will decrease and will lead to companies under-recovering their debt costs during the price control period, in the event of a decline in inflation.

An alternative option for deriving a CPIH real allowance would be to utilise outturn CPIH inflation data. This methodology would simplify the derivation relative to the other options considered and would largely mitigate risk for investors in recovering nominal debt costs, as the inflation element of the cost of debt is recovered as a capital gain on the RAV and the remaining real element is recovered as a return on the RAV. However, it risks introducing volatility in the allowed real debt component of revenues, but this could be mitigated by utilising a suitable trailing average measure or by trueing-up forecast inflation for the outturn inflation at the end of the price control.

It is worthwhile noting that it is important for Ofgem to consider that in a real framework investors anticipate the nominal cost, while the remuneration of the costs provided for in the regulatory settlement is 'back-end loaded i.e. deferred in the future. The consideration of a low cost of debt allowance combined with the delay in the recovery of the inflation could create several difficulties for companies in making the necessary investments and could potentially exacerbate financeability problems with certain companies.

Cost of Equity questions

Risk-free rate questions

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

As Ofgem, along with other GB regulators, determine the cost of equity based on their TMR approach, we consider that if the cost of equity were to be indexed, then we would consider that this would be best served, as Ofgem have proposed, by indexing it to the RFR only, since this is the most straightforward and objective method for indexing changes in the cost of equity.

However, Ofgem have only focussed their analysis on how the cost of equity index mechanism would work, rather than appropriately assessing whether indexation of the cost of equity is superior to setting an ex-ante allowance with an included uplift. This is important, as with this mechanism Ofgem have passed on the impact of changes in the cost of equity to consumers. Ofgem need to consider whether cost of equity indexation is to be applied in an objective manner, and if the RFR is volatile and unpredictable, such that forecasting error in ex-ante outweighs increases in risk and credit metrics. If both can be answered with a yes then Ofgem should consider applying cost of equity indexation for RIIO-2.

In our responses below, we propose that if based on nominal gilt yields, less HMT/OBR CPI forecast (complemented with potential outturn true-up), then the cost of equity index can be set in an objective manner. However, the second question is not as clear. Firstly, it is unclear how well forward curves predict future outturn yields, however as of yet, there appears to be no systemic bias. Secondly, UK regulators have to date set ex-ante RFR allowances, which incorporate an uplift for expected changes in rates (based on short-term evidence). In theory combining the two can result in an ex ante RFR assumption that near equals the RFR index, given market expectations. However, indexation imposes risk on credit metrics and Ofgem needs to ensure sufficient head-room in financial ratios, when setting the price control parameters, to protect companies against financeability problems in the instance where RFR declines.

If a RFR indexation mechanism was not applied in RIIO-2, then an ex ante allowance should be set by Ofgem, adjusting the short-term market evidence to incorporate an uplift for expected changes in interest rates. This approach is consistent with UK regulators' approach of placing greater weight on long-run evidence to avoid setting the allowed rate of return which varies with the business cycle, which contributes itself to co-variant risk, as well as regulatory risk. Such a scenario would inappropriately restrict the allowed returns to regulated companies over the price control period, leading to underinvestment.

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

We agree with setting the allowed RFR with reference to the yields on UK gilts with 20-year maturity. It is appropriate that the tenor of the RFR should be set, consistent with the investment horizon of equity investors in energy network assets. Given that UK energy networks typically have asset lives of around 20 years (the typical remaining (regulatory) asset life is 22.5 years, based on the 45-year RAV depreciation), this implies a 20-year investment horizon for equity investors in UK networks. Also, in practice, survey evidence shows that the vast majority of corporations and financial analysts report using the yields of long-term government bonds of 10 to 30 years.

The above suggests that the 20-year UK gilt yields should be used in order to match the 20 year investment horizon of energy networks.

However, we do not agree with the use of yields on index-linked gilts for determining the real RFR allowance directly. Instead we would propose that Ofgem draws on evidence from nominal gilt yields and adjusts for inflation, to express the RFR allowance in real terms.

In para 3.32 of the December sector consultation, Ofgem appear to acknowledge that that the stability of network charges is an important consideration in the design of any equity indexation approach. The 20-year nominal gilt yields have been more stable than yields of shorter-term maturities, which are a useful feature for an RFR index and supports our previous submission on the appropriate RFR tenor. RPI-linked gilt yields, on the other hand, have exhibited greater volatility than nominal gilt yields, with the yields on 20 year real gilts being just as volatile as those for 10-year and 15-year real gilts since 2010. As such, RPI-linked gilt yields do not meet the stability criterion required for a cost of equity index.

ILG may also be an inappropriate proxy for the RFR, given the liquidity risk premium included within their yields. This premium compensates the risk of incurring costs trading ILG, as evidence shows that the ILG market is far less liquid than nominal gilts. With longer-dated real gilts, there is also an excess demand or "structural imbalance" from obligations coming from institutions such as pension funds, which result in depressed yields.[11]

20-year ILG are therefore a less suitable measure for the RFR compared to the 20-year nominal gilts given their greater volatility – which would lead to a less stable cost of equity index – and the fact that they provide a less objective measure of RFR given the excess demand from obligations on pension funds.

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

We do not agree with the use of a one month average of returns as the optimal estimation period. This would only capture the most recent market evidence and would not be reflective of the variations in interest rates over a given year. There is also a risk that unusual circumstances or activities occurring in the estimation month could create atypical fluctuations in the allowance. The use of a one-month average would therefore provide for a RFR allowance that is overly reactive to short-term interest rate changes.

Setting the allowance with respect to a longer averaging period of gilt yields would reduce fluctuations and provide a more stable measure of the RFR. It is worth noting that the European precedent of RFR indexation mechanisms supports the use of an averaging period of at least 6 months, which help protect against downside risk.[12]

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

In recommending the use of 20-year nominal gilts, as the appropriate proxy for the RFR, we inherently disagree with the proposal of deriving a CPIH real RFR by adding an expected RPI-CPIH wedge to RPI-linked gilt yields.

Ofgem's proposed method effectively incorporates a 20-year "breakeven" inflation measure, which is the difference between the yields of 20-year nominal gilt and inflation-linked gilt. The resulting 20-year breakeven inflation measure, used in this instance, may be a poor measure of inflation, particularly at the long end, given the concerns addressed in FQ 6 around the excess demand from pension funds for real gilts. The adoption of CPIH indexation also complicates the use of break-even inflation given the absence of an equivalent market based CPIH measure, which requires an adjustment of the RPI-CPI wedge. This would add further complexity into the derivation of a real allowance due to the variations between the forecast and outturn RPI-CPI wedge, which could introduce an uncontrollable cost for network companies. The wedge can present NPV neutrality concerns and Ofgem need to ensure that this is properly addressed.

Overall, Ofgem's implied adjustment for inflation (adding RPI-CPI wedge to RPI ILG yield) is less objective, and less stable, than by deflating nominal gilt using CPI inflation. The use of nominal yields would instead provide for greater stability and objectivity in the estimation of the RFR. This more objective approach in determining the RFR index (i.e. Ofgem's "alternative approach") would avoid the uncertainty concerns with the RPI-CPI wedge by deriving a real CPIH gilt through the deduction of

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[11] *"yields are likely to remain depressed relative to economic fundamentals for the foreseeable future"* Schroders (June 2016), "Pension funds and index-linked gilts - A supply/demand mismatch made in hell"frotn

[12] In Italy the AEEGSI sets a real RFR based on 1-year average of 10Y gov't bond yield, subject to a lower bound of 0.5 per cent in real terms. In Finland the EMVI sets the RFR annually based on the greater of i) 6-month average of 10Y Finnish gov't bonds in the preceding year, and ii) 10-y average yield on 10Y Finnish gov't bonds in previous ten years.

expected CPI. This can be done using the 5-year CPI forecasts from HMT or the OBR. Either of which could provide objective forecasts of CPI, with the HMT forecast representing the consensus estimate of c. 20 forecasters (including investment banks and macro research companies). Alternatively the Bank of England's CPI target could be as a measure of expected inflation, with the benefit of providing a more long-term view of CPI compared to the 5-year forecasts from HMT and the OBR.

An alternative (or complementary) approach would be to true-up CPI forecasts for outturn CPI in order to mitigate forecasting error. As long as the true-up does not introduce undue volatility then this approach could be considered reasonable e.g. trued-up based on a rolling average of CPI or trued-up at the end of the price control.

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

We believe that Ofgem have highlighted the main concerns that we have raised following the publication of the RIIO-2 frameworks consultation and decision documents. We welcome Ofgem's commitment in adopting the TMR approach at RIIO-2, in line with recommendations from UKRN commissioned report. However, we have concerns in how Ofgem have interpreted the evidence to inform the TMR, outlined in the responses below. We would also draw Ofgem's attention to the reports produced by NERA for the ENA on the TMR[13].

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

We agree with Ofgem's proposed methodology to estimate the TMR, based on long-run historical averages, as the best available evidence on investors' future expectations, and taking into account forward-looking approaches as a cross-check. The use of historical returns, as evidence of investors' future expectations, is supported by the stability of the TMR over time, as documented in financial literature. However, Ofgem's approach has led it to propose a TMR working assumption of 6.25 to 6.75% (real, CPIH), placing significant weight on the long-run realised returns range of 6 to 7% (real, CPIH) or 5 to 6% (real,RPI) cited in the 2018 UKRN report.

We do not consider that Ofgem has properly addressed the issues raised by stakeholders, in relation to their evidence base in the December sector consultation, and during the bilateral meetings between Ofgem and the ENA members. BREXIT specifically has not been mentioned by Ofgem in relation to the TMR. In any event, we believe that uncertainty, in particular around BREXIT, should not be considered as part of the TMR.

Historical Realised Returns Evidence

The 2018 UKRN report's proposed TMR in RPI terms (5 to 6%) is around 150bps lower than the 2003 UKRN, according to Ofgem, because of the lower realised returns up to 2018 (c. 25bps), lower upward adjustment from geometric to arithmetic mean (c. 25bps) and a switch from RPI to CPI(H) inflation (c. 100bps). The UKRN authors have based these adjustments on two key recommendations for estimating the TMR at future price reviews: (i) the use of CPI as the basis for both determining allowed WACC in real terms going forward and for analysing historical real total market returns going back to 1900; and (ii) a downward adjustment of around 1% to the simple arithmetic mean of historical realised returns to take into account predictability of returns at long horizons. We have concerns

[13] NERA, (November 2018), "Further evidence on the TMR", a report for the ENA, and NERA, (November 2018), "Review of UKRN Report Recommendations on TMR", a report for the ENA.

around the validity of these recommendations, with adherence to them leading to long-run realised returns estimates that are understated due to:

- **Reliance on a flawed historical CPI measure** – the UKRN authors draw on the historical inflation data labelled as CPI in the Millennium dataset published by the Bank of England (which back-cast CPI over the period from 1900 to 1989, its first official publication date) to determine historical real returns. NERA's analysis in their report[14] shows that the historical CPI inflation (BoE) Millennium dataset does not provide a reliable or consistent measure of historical CPI inflation prior to 1987, a conclusion which is acknowledged by the ONS and academic research. The utilisation of this flawed measure of historical CPI, by the UKRN authors, results in their conclusions of the historical TMR being substantially downwardly biased. As such, NERA conclude that instead of drawing on this unreliable CPI series, the historical real TMR should be estimated using RPI inflation as it represents the most reliable measure of UK inflation going back to 1900 and that it is reasonable to retain the DMS study's RPI inflation data as a basis for analysing historical real returns.

- **Unjustified downward adjustment to account for the alleged predictability of returns** – in contrast to the CMA's position in this issue, the UKRN report's authors state that the evidence base for predictability of returns has strengthened and that a downwards adjustment of around 1% to the simple arithmetic mean of historical realised returns is therefore justified in order to account for the alleged predictability of returns at long horizons. NERA conclude that the UKRN report's conclusion is contentious, highlighting that there is no recent evidence that supports an overturning of recent regulatory precedent on this issue of returns predictability, including that used by the CMA in its 2014 NIE review, and that established TMR estimators by Blume and JKM, which also consider serial dependence, instead support an adjustment to the arithmetic mean of the order of a maximum of 30 bps for long investment horizons.[15]

Additionally, Ofgem presented a hypothesis during an Ofgem-ENA workshop that it can use an RPI-deflated TMR in a CPIH framework without adjustment as investors' form their expectation of returns based on the official inflation index at the time, which used to be RPI but has now switched to CPI/CPIH. This hypothesis is a substantive departure from regulatory practice, and one that lacks any regulatory or academic support – indeed the UKRN report recommends using a real TMR deflated by CPI in a CPI framework.

For the purposes of determining a forward-looking CPIH-deflated TMR for setting the cost of equity allowance at RIIO-2, the historical RPI-deflated TMR should be adjusted upwards by around 100-130 bps to reflect the expected RPI-CPI wedge. We recommend that Ofgem derive the forward-looking CPIH-deflated TMR in this manner, as it will provide the same nominal returns in expectations as using an historical RPI-deflated TMR. Thereby fulfilling the expectation that the switch to CPIH indexation will be revenue neutral.

Cross check Evidence

<u>TMR measured in USD terms</u>

Ofgem appear to be testing whether UK long-run historical average real returns deflated by the BoE's historical CPI series from the Millennium dataset is consistent with other evidence of long-run historical average real returns. Specifically, whether the historical UK CPI inflation series can be approximated by converting historical US CPI inflation into UK inflation using changes in the real USD:GBP exchange rate. The argument has been based on the assumptions that relative Purchasing

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[14] NERA, (November 2018), "Review of UKRN Report Recommendations on TMR", a report for the ENA.
[15] NERA, (November 2018), "Review of UKRN Report Recommendations on TMR", a report for the ENA.

Power Parity (PPP) holds in the long-run[16]; however, there are a number of points which suggest that Ofgem's arguments that PPP holds in the long-run and that real returns are comparable in GBP and USD terms as a result of this assumption, is flawed.

Relative PPP theory suggests that the elasticity of exchange rates over time are systematic and proportional to the changes in relative inflation. However, there are practical limitations to this theory, which undermine Ofgem's arguments. There are multiple circumstances in which the elasticity of exchange rates is not dependent on the change in relative prices, which implies that PPP does not hold. For example, PPP theory makes the assumption of no trade barriers or transaction costs. The presence of a transaction cost in reality would create an interval within which the real exchange rate can fluctuate without changing prices. Other examples include changes in underlying productivity and technological advancement and changes to market conditions. Thus, we believe there is good reasoning to expect real market returns in GBP and USD to differ when using CPI-deflated returns.

Dividend Growth Model (DGM)

CEPA's previous specification of their DGM produced substantially understated forward-looking TMR estimates, due to the implausibly low assumptions around both short-term and long-term dividend growth rates. CEPA have updated their March 2018 DGM evidence using updated data on dividend yields and further sensitivities on growth rates. The three critical assumptions that underpin CEPA's updated two-period DGM (Total Equity Yield, short-term and long-term growth rates) have led to a downwardly biased nominal TMR estimate, one that is substantially 7 to 8% (real, RPI-deflated) below independent estimates of the TMR from the BoE's DGM, which the CMA relied on in its 2014 NIE determination.

In particular, the three different sensitivities for the long-term growth assumption all understate the expected nominal growth. NERA[17] consider the upper bound value to be the only reliable estimate of the TMR as it uses a weighted average of UK and International GDP growth assumption as it considers that FTSE All-Share companies derive over 70% of their earnings from outside of the UK. However, CEPA's methodology to calculate the international long-term GDP growth of 5.3%[18] appears to understate expected growth. If drawing directly on long-run global growth rates instead, and weighted for the source of FTSE revenues, consistent with the approach followed by BoE, the long-run international GDP growth rate would be around 5.9%. Both the low and midpoint scenarios' real growth rates have been derived based on RPI outturn inflation, but the nominal forecast have been derived with respect to expectations of CPI. CEPA's inconsistency in the inflation index used understates the expected nominal growth in both scenarios by at least 80 bps.

Investment managers and advisors TMR projections

Ofgem also consider TMR projections published by a selection of investment managers, as well as the maximum projection rates prescribed by the FCA, for the purposes of marketing retail financial products, which support an average nominal TMR of 6.59%. Oxera, in their report to the ENA, identify a number of limitations in their review of these evidence sources.[19] Oxera highlight that the FCA-prescribed 6 to 7% nominal TMR range is low relative to the range of evidence considered. This is a result of the FCA attributing significant weight to the lower end of the range of potential estimates when prescribing its TMR range in order to ensure its objective of minimising the chances of consumers suffering from overly optimistic performance forecasts. This is in contrast to Ofgem's

[16] The theory predicts that changes in the nominal exchange rate will exactly offset differentials in inflation rates between the two countries.
[17] NERA, (November 2018), "Further evidence on the TMR", a report for the ENA.
[18] CEPA apply an uplift calculated as the difference between the short-term international and UK GDP growth rates, and adds this to the long-run UK GDP growth rate of 4.5 per cent, which provides a long-term growth assumption of 5.3 per cent.
[19] Oxera, (February 2019), "Review of RIIO-2 finance issues: rates of return used by investment managers", a report for the ENA.

financing duty which requires them to take a more balanced approach towards estimating the TMR, taking into account the interests of both customers and investors.

Oxera also recommend that no weight is placed on the evidence from investment management firms, as academic research has established that forecasts made by professional market participants have poor predictive power in informing investors' expected returns. Moreover, the majority of the underlying publications explicitly state that the figures presented cannot be used as estimates of future returns, which goes against Ofgem's intention of using this source of evidence.

NERA also find that survey evidence is an unreliable source of investor expectations of returns given the issues around respondents' understanding of the question being asked and the high sensitivity of the responses to the framing of the question, and whether the required returns are intended to be nominal or real[20]. The CMA criticised the use of survey evidence in its 2014 NIE determination for similar reasons[21].

Based on the conclusions from Oxera and NERA, we consider that evidence of forecasts from investment managers and advisors are of limited applicability to regulators when setting the TMR in the context of a price control and should therefore not be relied upon.

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

As highlighted in our response to FQ10, we do not consider the 2018 UKRN report's adjustments to the proposed TMR for lower upward adjustment from geometric to arithmetic mean (c. 25bps) and a switch from RPI to CPI(H) inflation (c. 100bps) is justified.

FQ12. Do you have any views on our assessment of the issues that stakeholders raised regarding beta estimation, including the consideration of: all UK outturn data, different data frequencies, long-run sample periods, advanced econometric techniques, de-gearing and re-gearing, and the focus on UK companies?FQ13. What is your view on Dr Robertson's report?& FQ14. What is your view on Indepen's report?

Indepen report

The Indepen report addresses some of the issues raised by network companies in relation to the UKRN recommendations and provides recommendations on its preferred approach, some of which we broadly agree with. These include:

- **the support of the use of high frequency data** – Indepen argues that when choosing the data frequency, there is a trade-off between obtaining more data points (and making inference possible) and the noise introduced from the use of more data (breaching OLS's statistical assumptions).[22] They recommended the use of higher frequency data (daily or weekly returns) over longer windows and their recommended beta range is informed by using daily data.
- **Ordinary Least Squares (OLS) as the estimation model:** Indepen draw on GARCH, OLS and Least Absolute Deviations (LAD) models to see which fit the data better[23] when presenting its recommended beta range. They recognise that the results are not widely divergent and OLS can

[20] NERA (November 2018), "Further Evidence on the TMR", section 2.3

[21] From CMA (March 2014), Northern Ireland Electricity price determination, Final Determination, para. 13.156, p.13-31 and para 13.32: *"[…] the results of such surveys tend to depend on the identity and outlook of the respondents and how they interpret the questions being asked. Some surveys do not clarify the time frame over which the parameters are to be estimated (the long-term equilibrium ERP or a shorter-term estimate); whether an arithmetic or geometric averaging approach should be used; or whether the ERP is over bonds or bills or some other instrument."*

[22] Indepen (December 2018), Ofgem Beta Study – RIIO-2 Final, Main Report, Section 2, p.8.

[23] Indepen (December 2018), Ofgem Beta Study – RIIO-2 Main Report, Final, Section 2 and Section 5, pp. 10, 11 and 45.

continue to be used as the estimation model, provided that the time window and appropriate corrections to standard errors are considered.[24]

- **Existence of structural breaks** – Indepen acknowledging the existence of structural breaks in the data, recommends using period since the most recent structural break, as the estimation window (which implies the use of a five-year estimation window).[25] However, they still rely on data going as far back as 2000 to inform its recommended equity beta range.[26]

However, there are other Indepen recommendations where we do have concerns:

Beta Decomposition

Indepen's recommended beta range fails to incorporate the evidence from the beta decomposition of asset betas of some listed UK networks (including National Grid), although they do consider that a strong case can be made to do so. Indepen's concerns are that there is still uncertainty around the assumptions required and thus they do not recommend relying on results obtained through a beta decomposition until their three identified issues are resolved.[27]

In our view, there is enough support behind the assumptions required by Indepen, to justify the use of the National Grid's beta decomposition in the estimation of betas for RIIO-2. In finance theory, a beta decomposition approach is relatively frequent, being commonly referred to as a "bottom-up beta".[28] The evidence from finance theory provides answers to Indepen's three conceptual questions. Firstly, the decomposition should be done using asset betas because these are the correct measures of a segment's business risk, without introducing financing decisions into the beta. Secondly, the gearing used for de-leveraging the comparators' equity betas should reflect the actual gearing of the comparators', while the gearing used for re-leveraging the estimated asset beta should be a notional gearing level. Finally, the weights used should be based on the present value of future cash-flows, which, in our view, can be proxied by the proportion of regulated assets out of total regulated assets.

Beta decomposition is also relatively common in UK regulatory determinations. For example, Ofcom and the then Competition Commission, now Competition and Markets Authority have applied asset beta decompositions in their determinations.[29]

Leveraging/De-leveraging Adjustment

Indepen, while not estimating notional equity betas (opting to present raw equity betas only), point to an inconsistency in the leveraging process if observed equity betas are de-leveraged using their actual gearing value (based on an enterprise value gearing), it is inconsistent to then re-leverage them using a RAV-based notional gearing estimate. Indepen acknowledges that this would not be an issue if Market to Asset ratios are close to 1, i.e. enterprise value and RAB gearing are close.[30] However, for the cases where MAR is different from 1, Indepen recommends the use of a notional enterprise value level of gearing which is calculated as D/(RAB*MAR).

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[24] The differences in equity betas estimated using only GARCH and OLS specifications are on average 0.04, 0.06 and 0.05 for the estimation periods 2000-2018, 2008-2018 and 2013-2018, respectively. Based on Indepen's reported equity beta estimates. Source: Indepen (December 2018), Ofgem Beta Study – RIIO-2 Final, Section 5, p.45

[25] Indepen (December 2018), Ofgem Beta Study – RIIO-2 Final, Main Report, Section 2 and Section 5, pp.6,7 and 45.

[26] Indepen (December 2018), Ofgem Beta Study – RIIO-2 Main Report, Final, Section 2 and Section 5, pp. 5-7 and 45.

[27] Indepen's concerns include the issues: should the decomposition be applied to equity or asset betas?; if applied to asset betas, should a group average, group actual or industry specific gearing be used?; and are net assets the right way of measuring the weights?

[28] See for example Damodaran, A (2012), Investment Valuation: tools and techniques for determining the value of any asset, Chapter 8, p.197.

[29] Ofcom (28 03 2018): Wholesale Local Access Market Review: Statement, Annexes 17-27, pp.76 and 115-136.; Competition Commission (28 September 2007), BAA Ltd, A report on the economic regulation of the London airport companies (Heathrow Airport Ltd and Gatwick Airport Ltd), Appendix F, pp.F-7, F-8 and F-28 to F-31.

[30] Market to asset ratios is defined as Market Value of the company over the RAB.

Indepen does not provide a strong argument for not estimating re-leveraged equity betas. The fact that their comparator companies actual enterprise value gearing levels are below both Ofgem's notional gearing level and the Indepen "adjusted" notional gearing level[31] means that by not de-leveraging and re-leveraging, Indepen's recommended range is understating the equity betas. Using raw equity betas estimated directly by Indepen without de-leveraging and re-leveraging would be also be problematic for Ofgem as it would mean the notional gearing structure would be tied to the gearing decisions of relatively few comparators – this would involve adopting a common notional gearing assumption across all energy sectors.

Having set the formula for calculating a notional enterprise value level of gearing, Indepen also considers the MAR value to use. Given the issues surrounding the use of the actual MAR, Indepen opts for using a "normal" MAR of 1.1 as a starting point on the basis of evidence from water and energy network comparators, pointing to an average MAR of 1.1 and 1.2, respectively. The choice of a MAR above 1 implies that the new notional gearing measure will be lower, which will be reflected in lower re-leveraged equity betas.

It is necessary to make sizeable and uncertain adjustments to convert the raw MARs to a MAR that reflects only the UK and regulated parts of the businesses. This is recognised by Indepen, who cites circularity and valuation issues as reasons for not setting the MAR equal to the actual MAR.[32] However, unlike Indepen, there is no conclusive evidence that a "normal" MAR should be different from 1, given recent trends and the relatively wide intervals.[33] This means that, even if we were to accept Indepen's adjustment, it would have no effect on the notional gearing level. Moreover, Indepen's "adjusted" notional gearing has no precedent in UK regulation.

It is of note that Indepen's adjustment, which lowers the notional gearing level, also implies that a greater weight must be applied on the cost of equity in the WACC to reflect the lower level of leverage. Additionally, if Ofgem were to adopt this adjustment of notional gearing, it would then have to calculate a separate WACC for the purpose of assessing financeability, given that the financing metrics used by credit agencies do not take into account this adjusted notional gearing.

International Comparators

We agree with Indepen, that the use of listed UK examples is valuable when estimating betas, although a relative risk analysis should be undertaken first to ensure that these comparators are similar in their exposure to systematic risk. However, we do not agree with Indepen doubting the value of international comparators on the basis that the risk to UK energy may be dissimilar, given issues such as comparability of regulatory regimes. While we agree that companies from different countries may not be the most comparable evidence, it is also the case that they can be useful as benchmarks, provided a relative risk analysis is conducted. Such a comparison provides more data points for the beta analysis. Oxera and NERA have found that the equity betas of comparator European energy networks track closely the equity beta of National Grid[34]. This is consistent with investors' viewing these businesses as having similar systematic risk profiles.

[31] Indepen's estimates of enterprise value gearing are substantially different from Ofgem's notional gearing assumption of 60 per cent for all but one comparator. Even using Indepen's "adjusted" notional gearing measure, which is calculated using a "normal" MAR of 1.1 to adjust the RAB-based notional gearing of 60 per cent, we still see considerable differences for 3 out of the 5 comparators.
[32] Indepen (December 2018), Ofgem Beta Study – RIIO-2 Main Report, Final, Section 4, p.33.
[33] See our response for FQ17.
[34] See Oxera (February 2018), "The cost of equity for RIIO-2 - Ppepared for Energy Networks Association" and NERA (April 2018), "RIIO-T2 Beta and Risk Assessment", a report for National Grid

It is of note that other UK and European regulators have used betas from other countries in their determinations.[35]

For these reasons, Indepen's exclusion of evidence from international comparators leads to a recommended beta range that understates energy network risk.

In summary, we consider that Indepen does not provide strong enough evidence to estimate equity betas without de-leveraging and re-leveraging and further fails to take into account the evidence from the beta decomposition of National Grid, and evidence from international comparators. Indepen's proposed adjustment to gearing has no precedent in UK regulation and, even if we were to accept this, there is no strong evidence that adjusted MARs are significantly different from 1.

Dr. Robertson report

Dr. Robertson provides a similar view to Indepen, noting that higher frequency data provides more precision in the equity betas estimation process and sets out equity beta estimates which rely on daily data.[36] Dr. Robertson, similar to Indepen and our view, also recognises that the existence of structural breaks provides an argument against the use of very long run data. Also similar to Indepen, Dr. Robertson states that long-run estimates from GARCH and OLS are quite similar.[37] These values are consistent with NERA's previous conclusions on the UKRN report estimates, where they concluded that once consistent time periods and data frequencies are used, the results from standard OLS estimation and the MGARCH model proposed by MPW become very similar.[38]

GARCH

Both reports consider the use of GARCH models for estimating betas. The use of this complex model is argued to correct for potential biases in the beta estimation, butimplies a certain degree of subjectivity in the model selection, which will affect the transparency of the estimates. As noted above, both reports highlight that GARCH and OLS models produce consistent beta estimation results, evidencing that the use of an OLS model is not leading to betas that are under- or overstated.

Combined with the substantial increase in complexity associated with the use of GARCH methods, we consider that the benefits of implementing GARCH methods relative to standard OLS are questionable in a regulatory context. The rolling-window OLS approach may potentially provide a more suitable method for analysing time-varying properties of betas in this context as it offers the best trade-off between various regulatory objectives: it is easy to implement and well understood, it incorporates time-varying betas, and it minimises the scope for regulatory discretion/arbitrariness.

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

In estimating a notional equity beta range in their working assumption, Ofgem rely on Indepen's report, which presents only raw equity beta estimates of 0.55 to 0.7, and a narrower range of 0.57 to

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[35] For example, the CAA in its 2014 price review for Heathrow and Gatwick estimated an asset beta by reviewing evidence from airports from countries such as Germany (Fraport) and France (ADP): *CAA (2014), Estimating the cost of capital: technical appendix for the economic regulation of Heathrow and Gatwick from April 2014: Notices granting the licenses, pp.39-43*
Another example is a Portuguese waste regulator (ERSAR), which used UK water companies (Pennon, United Utilities and Severn Trent) as a benchmark to assess systematic risk for a Portuguese waste company: *ERSAR (31 July 2018), Proposal of an Asset Remuneration Rate for the determination of Allowed Revenues in the scope of Tariff Regulation for Urban Waste management services for the regulatory period 2019-2021, pp.49-51*

[36] Donald Robertson (April 2018), Estimating β, pp. 3, 39 and 40.

[37] Donald Robertson (April 2018), Estimating β, p.39.

[38] NERA (2018), Review of UKRN report recommendations on beta estimation, Section 5, p.23.

0.65[39], drawing on GARCH, OLS and Least Absolute Deviations (LAD) models, using high-frequency data over different estimation windows and relying on five comparators.

To arrive at an asset beta, Ofgem starts by de-leveraging a raw equity beta range of 0.6 to 0.7 (which is said to be consistent with Indepen's recommended range) using an average of the gearing levels of the five comparators used by Indepen, but multiplying it by a "normal" MAR of 1.1.[40] This adjustment appears to be based on Indepen's recommendation that the gearing used to de-leverage and the gearing used to re-leverage, should both be on a consistent basis (i.e. it is not consistent to have actual gearing based on Debt/Enterprise Value to de-leverage and re-leverage using notional gearing based on Debt/RAV)[41].

Ofgem arrives at an asset beta range of 0.35 to 0.36, assumed a debt beta range of 0.1 to 0.15, the same as Indepen's recommendation, based on the analysis of regulatory precedent and academic evidence.[42] It then re-leverages them using a notional gearing estimate of 60%, calculating their updated notional equity beta range of 0.65 to 0.76.

However, Ofgem's approach is neither in line with Indepen's approach nor finance theory. Ofgem estimate a notional equity beta, but de-leveraging the raw equity betas by adjusting the actual gearing of companies (enterprise value) using Indepen's normal MAR adjustment overstates the actual gearing level. This is not consistent with Indepen's approach, as Indepen applies its adjustment to the notional gearing estimate, and not to the actual gearing levels. When de-leveraging betas, the objective is to remove the financing effects from the comparators to obtain a measure of business risk, which is accomplished by using the firm's actual capital structure, and not some measure adjusted to reflect a notional level. By overstating the actual gearing levels when de-leveraging the raw equity betas, Ofgem is not correctly estimating a measure of business risk and understates the asset betas and, consequently, the cost of equity, thereby punishing outperformance. We also note Ofgem's use of an average gearing level to de-leverage the raw equity beta range. This is not conceptually correct. Given that the range is informed by betas of comparators, using an average gearing means that we are de-leveraging the beta of a company using a gearing measure that incorporates other companies financing decisions, which introduces an additional bias into the asset beta estimation.

We also consider that the debt beta assumption used by Ofgem, the same as Indepen's recommendation, is not well-supported. Most practitioners have assumed a zero debt beta – Ofgem's consultants CEPA assumes a zero debt beta in their recent report to Ofgem, and the UKRN report provides empirical evidence that the debt beta for UK energy networks is likely to be close to zero when using daily data.[43] It is of note that, as confirmed by the CMA, overall the assumed debt beta has a negligible impact on the equity beta and cost of capital, assuming de-leveraging and leveraging is undertaken correctly. [44,45]

Ofgem states that that the beta analysis for RIIO-2 should extend beyond the two pure-play water companies' and that it may it may be worthwhile considering international comparators' based on

[39] Indepen (December 2018), Ofgem Beta Study – RIIO-2 Final, Main Report, Section 5, pp.45 and 46.
[40] Market to Asset ratio is defined as Market Value of the company over the RAV.
[41] Indepen (December 2018), Ofgem Beta Study – RIIO-2 Final, Main Report, Section 4, pp.31-34.
[42] Ofgem (18 December 2018), RIIO-2 Sector Specific Methodology, Annex: Finance, Section 3, pp. 39 and 40; Indepen (December 2018), Ofgem Beta Study – RIIO-2 Final, Main Report, Section 3, pp.26-29; Indepen (December 2018), Ofgem Beta Study – RIIO-2 Final, Appendices D-H, Appendix E, pp.4-10.
[43] CEPA (February 2018), Review of the cost of capital ranges for Ofgem's RIIO-2 for onshore networks, p.51; S Wright, P Burns, A Mason, D Pickford (2018), Estimating the cost of capital for implementation of price controls by UK Regulators ("UKRN Report"), p55.
[44] The assumed debt beta affects the notional cost of equity only to the extent that leverage for the comparators differs from the notional assumption. If empirical leverage is the same as notional and consistent debt betas are used for un-levering and re-levering, there is no impact on the re-levered cost of equity.
[45] For example, at the BW 2015 appeal, the CMA assumed a debt beta of zero, noting that debt beta has very little impact on the overall cost of capital as BW's notional gearing level was similar to the comparators.

recommendations by stakeholders. However, Ofgem expresses some reservations around the suitability of these international comparators. We are of the view that empirical beta analysis should extend beyond the UK listed water companies and include evidence from European energy comparators; however this should be accompanied with a relative risk analysis to ensure that these comparators are similar in their exposure to systematic risk.

Although the listed water companies are valuable when estimating betas, it is our view that energy networks face higher risk than water networks in relation to system operability risks and greater exposure to stranding risk due to government's decarbonisation plans.

As highlighted in our response to FQ14, we believe that including evidence on European comparator networks to increase the sample beyond UK only utilities benefits the beta estimation process by producing more robust estimates. Both NERA and Oxera have empirically shown that evidence of European energy networks support an asset beta of around 0.4, which closely tracks the empirical asset beta of National Grid[46] – which we consider is the most direct comparator for SPT. This is consistent with investors' viewing the systematic risk of these businesses as having similar movements in systematic risk, therefore providing an appropriate benchmark for a UK regulated network. However we also believe that TOs face greater risks than other energy networks because of the relative complexity of the investment programme, as acknowledged by Ofgem at previous reviews. This would justify a continuation of higher asset betas for TOs relative to other regulated network assets.

In summary, Ofgem's adjustment to gearing levels is inconsistent with Indepen's approach and is also inconsistent with standard finance theory. The overstatement of actual gearing levels when de-leveraging the raw equity betas result in Ofgem not correctly estimating a measure of business risk, thus understating the asset betas, and by extension, the cost of equity. Indepen's proposed adjustment to gearing has no precedent in UK regulation and, even if we were to accept this, there is no strong evidence that adjusted MARs are significantly different from 1. We also consider that Ofgem should take into account the evidence from international comparators, provided that a relative risk assessment is undertaken.

Cross-checking the CAPM-implied cost of equity questions

FQ16. Do you agree with our proposal to cross-check CAPM in this way? & FQ17. Do you agree that the cross-checks support the CAPM-implied range and lend support that the range can be narrowed to 4-5% on a CPIH basis?

Overall, we do not agree with the different measures that Ofgem have employed under step 2 as cross-checks against their CAPM-implied cost of equity range.

As set out in our response to FQ10 above, our view is that CEPA's DGM, a key component of Ofgem's cross-checks, understates the expected TMR due to implausibly low assumptions around dividend growth. We also do not consider that the further sensitivity analysis in the sector consultation has addressed previous concerns around CEPA's model. Also outlined in this response is that Ofgem should place no weight on the return forecasts from investment managers and the FCA when estimating the TMR due to this evidence source's unreliability in informing investors' expected returns.

[46] See Oxera (February 2018), "The cost of equity for RIIO-2 - Ppepared for Energy Networks Association"; NERA (April 2018), "RIIO-T2 Beta and Risk Assessment", a report for National Grid and Oxera (March 2019), " The estimation of beta and gearing", a report prepared for the ENA (published post-consultation deadline

OFTO IRR

The equity IRRs for OFTOs winning bidders reported by Ofgem are 7.2 to 10.2% (nominal) or therefore 5.2-8.2% (real, CPIH) or 4.2 - 7.2 (real, RPI), with the most recent round (round five), as the lower bound. These figures are far higher than Ofgem's own proposed cost of equity range of 3 to 4% (real, RPI), and therefore support an upward adjustment to Ofgem's Step 1 range. We acknowledge though that the OFTO evidence reflects a leveraged equity return which may be higher than Ofgem's assumed notional gearing of 60%, although this is not reported by Ofgem.[47] Potentially taking into account higher levels of gearing, Ofgem concludes the OFTO evidence supports a cost of equity of 4% (real RPI), at the top end of its estimated range from step 1.

As set out in NERA's separate report for SPEN[48], OFTO IRRs are an unreliable and an unverified estimator for cost of equity. Bidders for OFTO projects bid and are evaluated based on their proposed revenue stream over the OFTO license period.[49] Even where equity IRRs targeted by investors for OFTO projects are stated in the bidding documents, the equity IRR is likely to understate the expected return given potential cost outperformance, tax, and financing outperformance over the operational life. In addition, the risk profile of the OFTO operational phase (under these late competition models) is lower than the risks faced by a TO undertaking a portfolio of capital projects.

Infrastructure Funds Discount Rates

Ofgem draw on the discount rates used by five out of six infrastructure funds to value their equity investment as a cross-check to the CAPM-implied cost of equity range for RIIO-2. Ofgem conclude that the relative risks of the component investments in the funds combined with the funds' shares trading at a premium to the NAV support the use of the funds' discount rate as a cross-check to inform and justify the 4% (real, RPI) upper bound of the cost of equity range for RIIO-2 and to demonstrate a decline in investors' expected returns over time. We are of the view that the justifications highlighted by Ofgem are incorrect and do not warrant the use of discount rates as an appropriate cross-check.

Firstly, Ofgem have stated that the asset composition of the infrastructure funds include those with higher expected risks than energy networks, highlighting the inclusion of overseas investments or investments including greater volume or revenue risk. We do not agree that the selected infrastructure funds are riskier than energy networks and are of the view that the funds' asset composition instead points to portfolio risk that is likely lower than that of energy networks. This is primarily due to the large proportion of several of the funds' portfolios being comprised of investments that are considered lower risk compared to regulated utilities, such as PPP projects, social housing and availability-based investments.[50] For example, 70% of HICL's portfolio consists of investments in PPP contracts.[51] Additionally, even where funds' portfolio investments face volume or revenue risks higher than those exposed to energy networks, most are hedged through long-term (or availability-based) contracts and some investments are supported by via some form of government subsidies which reduces their risk exposure e.g. renewable obligation certificates and Contract for Difference. Also, we do not agree that

[47] Ofgem states that the OFTOs may be as leveraged as 90 per cent at financial close, but the relevant gearing measure is the period to which the equity IRR corresponds. Source: Ofgem (December 2018) Consultation – RIIO-2 Sector Specific Methodology Annex – Finance, p.47

[48] NERA (March 2018), Review of Ofgem proposed WACC for Competition Proxy Model of delivering new onshore capacity investments

[49] The bidding criteria place a 60 per cent weight on the bidders proposed revenue stream and a 40 per cent weight on quality of the underlying assumptions. See e.g. Ofgem (October 2014), Invitation to Tender Document for Tender Round 3 (TR3): Westermost Rough, p.60-62.

[50] Third party report by PWC and BBGI's presented in BBGI interim presentation June 2018 showcase that the risk and return characteristics of PPP projects sit on the lower end of the spectrum and are below that of regulated utilities. See BBGI(2018) 'Interim Results Presentation', 31 August, p. 26

[51] HICL (2018) 'Interim Report for the six months ended 30 September 2018', 20 November, p. 26

oversea investments are implicitly riskier than those of UK based investments, as the benefits from geographic diversification may instead lower the funds' overall portfolio risk.

The above factors imply that equity investments in regulated energy networks are instead riskier and would have a cost of equity higher than the 7.2% nominal quoted by the infrastructure funds.

Secondly, Ofgem highlight that a positive NAV premium implies that investors are willing to pay more than the value of the assets in the fund i.e. discount rate used by investors in the fund is lower than the discount rate used by the fund itself. We do not agree with Ofgem's methodology to estimate NAV premiums[52], and note that more consistent approaches could instead be adopted to check for any divergence between the discount rate used by funds and investors of the fund. For example, closed-end mutual funds and exchange traded funds use the closing price on the date of the publication of the results, calculating a NAV and the NAV premium at the end of each trading day. Internal calculations using this alternative approach imply a lower NAV premia.

In a separate report for the ENA[53], NERA have considered the change in portfolio allocation by HICL over time to understand its effect on the discount rate. NERA's analysis shows that the change in the HICL portfolio is equally likely to explain the decline in required returns. Their review of the portfolio of assets held by HICL demonstrates that only two of the noted "ten largest investments" held in 2013 are in HICL's portfolio as of March 2018. In addition, the geographic location of the asset has greatly varied, for example, with asset allocation to North America declining from 10% of the asset portfolio in March 2018 to only 2% in January 2013.[54] The material changes in the HICL portfolio mean that reliable conclusions on the change in investors' expected returns cannot be made, thus the view that investors' expected returns has declined is unjustifiable.

The funds' lower risk component investments relative to energy networks combined with a low NAV premium therefore suggest that the funds' discount rates are not an appropriate cross-check for determining the upper bound of the CAPM-implied cost of equity range.

We also do not consider that the MAR values presented by Ofgem provide any reliable evidence on investors' cost of capital, given other factors that affect MARs. Ofgem concludes that investors' expected returns exceed their cost of capital, given that the MARs for the three UK listed water companies is greater than 1 (i.e. companies traded at premium) for the majority of the last 9 years. However, NERA have shown in a separate paper[55] that it is necessary to make sizeable and uncertain adjustments to be able to make any inferences about investors' cost of capital from market capitalisation data. Adjusting NG's market capitalisation to exclude its US regulated and non-regulated assets, NERA derive a relevant MAR range of 0.35 to 1.46 that relates to NG's UK regulated T&D assets only. This broad range demonstrates the implausibility of drawing on MAR evidence for NG to inform investors' expected cost of equity. NERA also show that United Utilities and Severn Trent have a MAR of approximately 1 after making adjustments for non-regulated, non-wholesale businesses, outperformance opportunities and pension deficit (surplus), suggesting that there is no evidence the investors' expected cost of equity is lower than the allowed returns for the water sector, and therefore providing no evidence that the returns are too high in energy.

[52] Ofgem (2018), 'RIIO-2 Sector Specific Methodology Annex: Finance', footnote 40
[53] NERA (November 2018) Further evidence on the TMR, a report for the ENA.
[54] HICL Infrastructure (January 2013), Quarterly Factsheet – January 2013; HICL Infrastructure (May 2018), Annual Results Presentation: Year to 31 March 2018.
[55] NERA (December 2017) Implications of Observed Market to Asset Ratios for Cost of Equity at RIIO-2.

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

We recommend that Ofgem cross-checks their CAPM-implied cost of equity range to other regulatory price control settlements and CMA precedents.

We wish to highlight to Ofgem the report produced by Oxera for the ENA on the asset risk premium (ARP) and debt risk premium (DRP) differential, which provides for a crucial cross-check as to whether the sector specific consultation proposals for the overall CAPM-implied cost of equity provides a ‘sensible market-based’ result - the report will be provided to Ofgem following the sector specific consultation response deadline (14 March 2019).

Oxera’s analysis is based on the financial theoretical principle that the risk of equity (whether for levered or unlevered) is always greater than the risk of the debt of the same company or asset. As such, there will be a differential between the expected return on assets (i.e. ARP) and the expected returns on debt (i.e. DRP), where the ARP is larger than the DRP.

Oxera have compared the ARP-DRP differential implied by Ofgem’s current RIIO-2 proposals with the ARP-DRP differential based on empirical evidence of various UK (and US) regulated entities’ and utilities’ cost of capital, concluding that Ofgem’s proposed range produces a ARP-DRP differential which is significantly below that produced from previous regulatory precedents and market evidence. Oxera’s analysis therefore suggests that Ofgem’s proposals on the allowed equity fail to compensate for the relative risk of holding equity rather than debt for the same asset.

Fundamentally this implies that at the building blocks level, Ofgem’s equity return proposals are incorrect and that Ofgem need to reconsider and revise one or more of the CAPM parameters in order to ensure that proposed RIIO-2 cost of capital meets the aforementioned ARP–DRP test criteria.

Expected and allowed return questions

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

We do not agree with Ofgem’s proposal to adjust the allowed cost of equity of towards the bottom end of the range (4% (real, CPIH)) due to its consideration that the allowed rate of return (AR) should be set below the expected rate of return (ER) (as provided by the CAPM under step 1) to reflect investors’ expectations of outperformance. We do not accept that this is, in principle, an appropriate or effective approach to incentive regulation and, in any event, have identified a number of logical and practical flaws with Ofgem’s current proposal, which we detail below.

Ofgem base this proposal to adopt a downwards adjustment of 50bps to the allowed cost of equity for RIIO-2 on the theoretical arguments made by Mason, Pickford and Wright (MPW) in the 2018 UKRN report; and on its own analysis of companies’ outperformance in previous price controls, yet there is no clear evidence as to why it should apply, or apply at that level, in relation to the RIIO-2 framework.

In their report to the ENA[56], Frontier detail how MPW have ignored or misunderstood the fundamental conclusion of regulatory economics, which is that it is impossible to simultaneously satisfy allocative, productive and dynamic efficiency. Forcing the convergence between the AR and ER to satisfy allocative efficiency cannot be done without compromising productive and dynamic efficiency. Regulators and policymakers have been very clear that customers’ interests are best served by through promoting productive and dynamic efficiency (achieved through the application of incentive

[56] Frontier (March 2019), “Adjusting baseline returns for anticipated outperformance: A critique of Ofgem's proposals”, a report for the ENA.

based regulation) ahead of cost-plus regimes that promote allocative efficiency. Such a move would undoubtedly lead to poor outcomes for consumers

The outperformance data which Ofgem have used to justify and calibrate the adjustment is selective, relying entirely on the RIIO-1 price controls and the last set of pre-RIIO controls, leading Ofgem to making conclusions on outperformance that cannot be supported. Although the data reveals significant outperformance, it varies strongly from sector to sector. Indeed, extending the time horizon of the dataset to include previous price controls – which have included periods of significant underperformance – provides a more rounded view of company outperformance. This demonstrates that regulation is not a one-way bet. What is also clear is that the SPEN companies have been consistently accurate in their forecasting.

Company outperformance can be shown to be heavily influenced by the efficiency performance of the operators, which in turn is driven by quality of the incentive-based model coupled with the stable approach to assessing the financing requirements of the businesses as applied by the regulator. There is also influence from both genuine forecasting uncertainty and the quality of the diligence undertaken by the regulator in the calibration of incentives and the setting of targets at each source of potential outperformance. Forecasting error has become a common issue for regulators post-GFC, whose effects have created a genuine difficulty in forecasting certain elements of price controls.

Ofgem's analysis of historic performance therefore cannot be the basis for the existence of the adjustment and it cannot support reliable calibration.

The range of changes to the price control methodology that Ofgem have proposed for RIIO-2 would markedly lower the scope for outperformance in RIIO-2 relative to RIIO-1. These include Ofgem's proposals to:

- Tighten calibration of incentives through price control deliverables and license obligations;
- Greater use of uncertainty mechanisms and indexation;
- Reduction of price control duration;
- Dynamic target setting;
- Lower incentive rates; and
- Introduction of Return Adjustment Mechanisms (RAMs).

If these present material changes to the incentive mechanisms, then recent historical levels of outperformance may not be representative of potential outperformance in RIIO-2. Basing the 50 bps AR reduction solely on historical performance *and* reducing outperformance opportunities appears to be illogical and would mean that Ofgem are running the risk of over-estimating any adjustment that might be necessary to bring the cost of equity package into balance.

Upon introducing such a novel adjustment approach, the wider consequences must be properly assessed. Neither Ofgem nor MPW have evaluated the impact that reducing baseline allowed returns to reflect expected outperformance would have on the efficiency properties of an incentive based regulatory regime. Frontier identify that introducing such an approach could lead to a range of unintended and negative consequences to customers as a result of: the erosion of investor confidence and increased investor risk; weakened incentives for efficiency and innovation; the distortion of incentives to invest; and the loss of clarity over price control calibration.

Ofgem appears to recognise the flaws and limits in its approach at paragraph 3.163 of the Sector Specific Finance Annex, where it says: *"However, we are confident that, on the balance of* *probabilities, investor expectations will be, at the very least, marginally positive, and that company capabilities are suitable adequate to fulfil such expectations."* There is a real risk that given the overall package which Ofgem is developing for RIIO-2, that will not be the case. Furthermore, this statement suggests that Ofgem will be content to adopt flawed decisions provided that, on the balance of probabilities, investor expectations remain marginally positive. We do not agree that that is an appropriate, or lawful, standard to which Ofgem should hold its decisions

Ofgem should properly review its own performance with a view to improving the quality of its analysis that feeds into target setting rather than applying a remedy that ignores the underlying problem and creates new problems of its own.

In adopting this proposal Ofgem have committed to departing from well-understood and longstanding regulatory practice of "aiming up" within the allowed return on equity range. Ofgem have also provided no justification for this unprecedented decision.

Frontier also argue that regulatory best practice is to take explicit account of the likelihood and consequences of making an error in the choice of a point estimate on the rate of return in the presence of uncertainty (i.e. one that may prove to be too high or too low). The main justification for aiming up is that the cost of underinvestment, arising in a situation where returns are set too low, would be greater to consumers that the cost of overinvestment, where returns are set too high. Costs of underinvestment to consumers include: network failures; lack of supply to new areas or new technologies; and lack of innovation that could reduce costs for future consumers[57]. This reasoning behind aiming up has been supported by previous CMA decisions[58] and by academic research, which has found that aiming up well above the central estimate is likely to minimise the expected losses to society from misestimating the regulated business's true cost of capital. Additionally, MPW themselves, upon review of regulatory precedent (particularly the CMA precedent), advise that there is a compelling case for regulators to aim up, although not to the extent that has been found necessary by other academics[59].

We conclude that Ofgem should revisit its decision on aiming up in view of longstanding regulatory best practice and the lessons from academic work. If Ofgem do decide to go against this precedent, both by picking the mid-point in their range of cost of equity, and then reducing this by a further 50 bps, they should provide substantial evidence that this won't place undue costs of underinvestment onto consumers.

FQ20. Does finance annex Appendix 4 accurately capture the reported outperformance of price controls?

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

The detail in appendix 4 has now been largely superseded in Ofgem's annual performance reports published on 8 March 2019.

We have engaged extensively with Ofgem on the development of performance measures and the RIIO accounts exercise. SPEN previously commented on the need for comparability around performance and financing and for extreme caution on publishing any information that has not been completed in a consistent manner. It should be highlighted that performance in appendix 4

[57] Oxera (2015), Agenda article 'Aiming high in setting the WACC: framework or guesswork?' March 2015
[58]Competition Commission (2007), 'BAA Ltd: A report on the economic regulation of the London airports companies (Heathrow Airport Ltd and Gatwick Airport Ltd)', presented to the Civil Aviation Authority, 28 September, paras 4.106–8.
[59] Dobbs, 2011, Modelling Welfare loss Asymmetries Arising from Uncertainty in the Regulatory Cost of Finance, https://www.staff.ncl.ac.uk/i.m.dobbs/Files/Welfare%20loss%20JRegE.pdf

incorporates significant subjectivity as the price controls are in progress, for example ED-1 is less than 50% complete, incentive performance is inherently difficult to forecast and 'true up' for output measures are not incorporated or other enduring value adjustments consistently. SPEN welcomes the addition of Weighted Average RoRE in the most recent annual performance reports which alters the results presented in appendix 4.

We believe that RoRE should not be viewed as a standalone measure and Ofgem should also promote prominence to other measures such as ROCE and ROA, as evidenced by the CMA.

In addition performance measures need to highlight the cost of debt allowance for Network Owners is provided on a real basis however the interest rate on the majority of company debt is on a nominal basis. Therefore the RoRE measure does not represent cashflow performance.

Financeability questions

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

As stated in the consultation and in the Electricity Act 1989, Ofgem have a duty to have regard to network companies' ability to finance their activities in a manner best calculated to promote efficiency and economy. It is in that vein that Ofgem must ensure that the Financeability assessment is comprehensive and evidence based to ensure this obligation is met for the RIIO-2 period under all potential scenarios (Both Positive and Negative).

Historically Ofgem have assessed financeability through the methodologies set out by the various Credit rating agencies that use the following factors to gauge financeability:

- Regulatory Environment and Asset Ownership Model
- Efficiency and Execution Risk
- Stability of Business Model and Financial Structure
- Key Credit Metrics

We would support the continued use of these factors are a guide on how Ofgem will assess financeability in RIIO-2 but would suggest that further analysis is required to ensure that both Equity and Debt elements of financeability are represented within the assessment undertaken.

When targeting a credit rating, ratios should be set to achieve mid-cycle ratios – ratios at a level that are comfortably above the minimum prescribed ratios for a particular rating. Negative rating pressure and downgrades develop when a company is routinely close to the bottom of the range of acceptable credit ratios for their current rating.

The objective for Ofgem and the Network Owners is to set financial parameters for the RIIO-2 price controls that allow the companies to deliver an efficiently financeable plan that will offer an adequate return to investors at the lowest possible cost to customers. It is therefore in the consumers' interest for companies to comfortably achieve, over the short and long term, the financial ratios used by credit rating agencies to determine an investment grade rating. An investment grade rating is ultimately required to facilitate access to capital markets on terms which promote long term efficient financing and therefore consumer bills.

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

The consultation listed the following as potential company actions to combat financeability issues:

- Dividend policies can be adjusted to retain cash within the ring-fence during the RIIO-1 or RIIO-2 period
- Equity injections can be used to reduce gearing
- Expensive debt or other financial commitments could be re-financed
- Companies can propose alternative capitalisation rates and/or depreciation rates, if appropriate.

While the options listed out above can impact financeability, the usefulness of these actions as long term levers for financeability adjustments is limited. For example the use of capitalisation rates/assets lives as a means to improve financeability will only have a short term impact and could potentially create a cash flow issue in the medium to longer term which would have to be alleviated through a change to the overall parameters of the price control.

Currently Ofgem assess financeability on a notional company basis which in essence should ensure that the regulatory package as a whole allows the notional company to finance the delivery of its efficient business plan.

Stress testing incorporating foreseeable up and down side scenarios on the notional and actual forecast financeability must be performed. This is essential to ensure companies are robust enough to retain an investment grade credit rating within the forecast range of expected price control variables.

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

The stated objectives of the Cash Flow Floor (CFF) are as follows:

(i) Strengthen the ringfence and support the creditworthiness of actual Licensees in the current low cost equity environment.

(ii) Protect consumers and debtholders from downside scenarios while leaving shareholders fully exposed to incentives on cost and quality of service.

(iii) Preserve incentive on Licensees to manage their financial structures in a reasonable and prudent manner

This development and approach to financeability could undermine the extent to which financeability tests are deemed by the markets to be meaningful, binding and robust cross check on the calibration of the RIIO-2 package.

The application of the floor is likely to be both costly and time consuming. We have not seen an impact assessment of considering potential costs and benefits of the floor despite its significance and complexity. In absence of this it cannot be assumed that the floor will create a public benefit.

It is possible the proposed CFF mechanism may be counterproductive in terms of reducing the cost to the consumer. Capital markets are already interpreting this approach as Ofgem being willing to allow the credit worthiness of the industry to decline. This will lead to higher financing costs for Network Owners. It will also be important that Ofgem ensures any decision it takes in relation to CPM is consistent with any approach, e.g. in relation to gearing, that it develops for RIIO-2, including any CFF mechanism.

Any likelihood of sustained dividend restrictions will reduce investor appetite for the sector.

To date the CFF has not been a feature of established price control regulation. We understand the objective of the mechanism is to ensure the creditworthiness of the licensees in the current low cost of equity environment. We believe financeability can be achieved with readily available alternatives at

Ofgem's disposal that are less intrusive and costly to implement. However, we are concerned by comments such as that in paragraph 11.11 of the Sector Specific Consultation that use of a CFF would create an *"...ability to be less constrained in setting the cost of equity."* Given its various duties, we do not consider that to be a reasonable or lawful approach for Ofgem to take. Ofgem must ensure that any new mechanism it introduces can practically achieve appropriate objectives in a way which is in consumers' long term interests.

The CFF in its current form also only represents short term relief and would not correct the underlying issue regarding insufficient liquidity through calibration of Price control. If existing mechanisms are not sufficient, recalibration of the RIIO-2 framework and assumptions should be considered first in principle.

The CFF may result in a short term liquidity improvement but this does not necessarily result in a Financeability improvement across the period. This therefore reduces the usefulness of the floor as a tool to improve financeability across the RIIO-2 period.

Normally this type of intervention would be required to address a failure that has resulted in the market as a whole. If there is evidence that networks might not be financeable (not solid investment grade or appropriate headroom to manage forecastable exposure to downside risks) then this problem cannot be addressed by transfers of cash overtime as the floor tries to do. The mechanism therefore is not achieving the aim of objective (i).

In terms of objective (ii) the floor may also aggravate rather than reduce the risk to lenders and consumers through explicit weakening of the financeability duty as a binding constraint as well as incentives on financial restructuring. This is due to the reduced role that Lenders will play in corporate governance due to the introduction of this safety net. The substitute regulatory oversight proposed by Ofgem would not provide the same level of scrutiny currently applied by the private debt providers and the wider capital markets.

As for objective (iii) the impact of the mechanism when activated has not been modelled in sufficient detail to ensure that there are no unintended consequences such as incentives on capital structures and or the unintended trigger events due to the robustness of trigger criteria. This opinion is shared by the ratings agencies Moody's and Standard & Poor's who point to the practical limitations of the mechanism in its current form and point to the potential for this mechanism to weaken the credit quality of the sector as a whole.

The CFF may lead to implication for funding structures for Network operators such as undermining the incentive for companies to determine the most efficient capital structure (Gearing) irrespective of notional structure. For example the mechanism would results in a bias towards Debt holders (Penalising equity) while Ofgem should be aiming to ensure one type of capital is not incentivised over another to avoid inefficient market distortions.

The floor appears designed to reduce equity returns but at the same time increase the riskiness of equity and will contribute to arbitrary departure from the risk-return balance.

We would also emphasise that the cashflow floor needs to be reviewed very carefully from a wider legal and practical point of view. By way of example:

- Would the circumstances leading to trigger to a cashflow floor have consequences in terms of the arrangements governing network operator debt.
- Could the circumstances trigger e.g. termination provisions in contracts with network operators, and therefore precipitate a wider insolvency/ business sustainability for the network operator.
- Restrictions on payments to related parties could prevent entirely legitimate payments.
- On what legal basis would Ofgem appoint a representative to the network operator board, (would Ofgem expect the constitutional documents of each network operator to be amended. Would that

person act as a director. Even if the person was an “observer” she may become a shadow director, and assume the significant legal responsibilities that apply to directors in law. How would Ofgem select the representative or additional independent director.

- How would any new restrictions on approval or payment of company dividends be made effective?

It is to be noted that network companies already have licence obligations to appoint at least two Sufficiently Independent Directors

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

In the event that the mechanism is required to be triggered it is appropriate that the actual short fall required between Expected Cash Available and Debt Service requirements is identified and made available to the relevant network provider in a timely manner to ensure the liquidity of the network is maintained. Variant 3 ensures that this is the case as well as referencing the requirements are based on specific company requirements and not those of a notional company which is advantageous in this situation.

However further detail is required around the relationship between notional and actual gearing levels and interest payments to ensure that the protections that the variant provides on a gearing cap and/or penalty deal with practical applications. For example in the case of a gearing cap with a % of debt costs being separated, as a situation could arise where a debt holder would have both included and excluded debt under this scenario and therefore not receive the required protection/assurances that the mechanism is meant to provide. This is also relevant for any debt that is refinanced after the March 18 deadline.

The main implications of the mechanism and variant 3 are the protections and reassurances it provides would be needed over a long term basis to satisfy the needs of Debt holders who typically have a maturity date longer than the current 5 year RIIO price control which the current methodology does not provide.

Further practical issues remain around the number of times the CFF can be accessed and around the timely release of funds how this requirement would fit into current revenue collection timescales operated by the ESO.

From an SP Transmission perspective the current provision for the ring fencing of the Network operator could have an impact on the SP Distribution network operator as part of the vertically integrated networks company. Payments to distribution networks could be impacted as part of the lock up mechanism which would disrupt the ED price control activity which will need to be taken account of as part of the proposed mechanism.

Corporation tax questions

FQ26. Do you support our proposal that companies should seek to obtain the “Fair Tax Mark” certification? & FQ27. Is there another method to secure tax legitimacy other than the “Fair Tax Mark” certification? Could we build upon the Finance Acts (2016 and 2009) with regards to the requirement for companies to publish a tax strategy and appoint a Senior Accounting Officer?

The Fair Tax Mark certification is not considered an appropriate method to “secure tax legitimacy”, whatever that phrase may actually mean. UK companies are required to comply with UK tax laws and the responsibility for monitoring compliance is the responsibility of HMRC, a Government department. The Fair Tax Mark is published by Fair Tax Mark Ltd, a Community Benefit Society, which has no connection to HMRC.

We understand only a few large companies have paid for the Fair Tax Mark accreditation and this is not a recognised means of obtaining any form of approval of a company's tax affairs.

Certain UK companies, including all UK companies in the ScottishPower group, are required by law to annually publish their tax strategy on the internet. In addition, companies are required to publish tax information in their statutory accounts including a reconciliation of the tax charge to the statutory rate of corporation tax. This information, and information provided to HMRC, is considered to be more appropriate than obtaining a fair tax mark. We would be willing to support Ofgem in developing a sector wide approach and addressing any specific concerns that Ofgem may have.

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

As a minimum a 1% of revenue materiality threshold should be applied. It is a very complex area attempting to separate regulatory allowance from other impacts on taxation paid to HMRC in a particular year.

Indexation of RAV questions

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

In principle any change in the inflation index used for price setting purposes should in theory be revenue neutral (i.e. it will not affect the present value of expected revenues charged to customers), if the "real RPI" allowed rate of return is adjusted upwards by the difference between RPI and CPIH inflation such that investors earn the same nominal return. Importantly, all other elements of the price setting formula must be appropriately adjusted to reflect the new inflation index (e.g. forecast totex allowances are appropriately adjusted for real price effects relative to CPIH to ensure nominal costs will be recovered).

As long as the same inflation index is used to calculate the real cost of capital and to index the RAV over time, the choice of inflation index used for regulatory purposes should have no impact on the present value of revenues charged to customers. However, the inflation index determines the balance between the amounts recovered within period versus those deferred into the future and as a result affects the profile of bills over time.

This needs to be communicated to all stakeholders to ensure they understand the full impact of the move to CPIH and are fully briefed on its NPV neutral nature.

Furthermore to ensure true value neutrality Ofgem would also need to recognise any additional costs associated with any change to the index, e.g. in relation to hedging or debt financing costs, which could be material. In addition the commitment to RPI that was made at RIIO price controls "until a CPI Gilt market becomes established" should be taken into account to make good on the commitment to value neutrality, over the long-term.

Given the complexity of the framework, PCFM calculations and licence mechanisms, and the numerous ways in which RPI is currently used in these, there is clearly a risk that not all the changes needed are fully recognised. This could lead to adverse impacts in various aspects of the price control, whether in the overall allowed returns (allowed real return + inflation applied to the RAV), cost allowances or revenue indexation.

Per paragraph 6.17 of the consultation it is vitally important that the CPIH forecasting issue is revisited to ensure value neutrality of the RPI/CPIH switch as the calculation of the wedge using CPI will not deliver the stated outcome as CPI and CPIH are not equal over time. (Historically the average difference has been around 12bps but has been as large as 80bps). This could therefore not deliver value neutrality as the other elements of the price control settlement will move with CPIH inflation index which will not be fully compensated by the substitute CPI based wedge.

Furthermore from paragraph 1.7 of the consultation, the calculation of the RPI/CPIH wedge would also require further clarification on when the switch over point would be and what data set will be used to derive the value of the wedge. Currently the use of the forecasted RPI/CPIH wedge using the forecasted values for 2023 for both RPI and CPI (as a substitute) seems somewhat arbitrary.

Therefore we would support a move to CPIH indexation of the price control settlement as long as it can be demonstrated in practice that the process would result in a price control settlement that would be NPV neutral for both consumers and investors alike. Further clarity is required on all aspects of the CPIH assumptions that Ofgem intend to use for RIIO-2 before the aim of value neutrality can be fully satisfied.

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

As indexation is central to the price control mechanics and is present throughout the whole of the price control financial model (PCFM), any change, even a single shift to CPIH, would be complex to model. This would be further complicated by a transition approach as in practice two versions of the RAV would need to be tracked over time which adds modelling risk. However this transition approach would have the benefit of reducing the risk of the CPIH-RPI wedge being eroded when setting the cost of capital at the beginning of the RIIO-2 period, instead maintaining the nominal cost of capital required by investors and preserving value neutrality.

In any case the relative simplicity of a “one off change” compared to that of a transition arrangement should arrive at the same objective of revenue neutrality as long as the significant risk that not all the price control adjustments are fully recognised and implemented in the correct manor is negated.

For example the choice of inflation index for the price review does not change a network company’s actual cost base and exposure to rising and volatile costs. The concept of Real Price Effects (RPEs) becomes more relevant and logically will be higher than in an RPI based price review. There is a risk that elements of the networks’ cost base that remain linked to RPI will not be fully covered. Under the current proposed “one off” approach RPE calculations would be much simpler than that of any transition approach leading to a further calculation required regarding a hybrid inflation measure to be used in any RPE’s calculation. Therefore any true up needs to ensure that this risk is effectively managed.

Furthermore, the assumptions surrounding the calculation of the RPI-CPI or CPIH wedge require further refinement, especially regarding the future relationship between these wedges as historical trends of movements between these indices may not hold true for the near future. For example there is currently little difference between CPI and CPIH however as the UK government moves to discourage buy to rent, we could observe CPIH falling notably relative to CPI, whereas if the current under-supply continues, and the labour market normalises, we could see real private rents rising at a similar rate as in the 1980s and 90s leading to a variation on the historical average difference between these measures and an impact of the wedge calculation real costs of capital and RAV indexation.

Therefore the proposed true up must ensure that all elements of the price control are reviewed and agreed upon to ensure no party is disadvantaged as a result of the movement to CPIH inflation. This may require extensive modelling of Ofgem’s assumptions under both a full RPI and CPIH basis to cross check that both deliver the same outcome on a nominal basis for both investors and consumers alike.

Regulatory depreciation questions

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

We agree, in principle, with Ofgem's proposal to maintain the existing depreciation policy of using economic asset lives as the basis for depreciating the RAV, ensuring an appropriate balance of costs and benefits across current and future generations of consumers. However a lower rate of regulatory depreciation may be required to address financeability issues. Therefore this assumption should continue to be monitored in relation to the financeability of the overall price control settlement proposed for the notional company in RIIO-2.

Capitalisation rate questions

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

We agree it would be too early in the process to consider capitalisation rates prior to receipt of company Business plans. The proportion of fast/slow monies is a component of a company's overall financeability and may be used a tool to address financeability issues, therefore it would be appropriate for companies to submit their proposal for an appropriate rate of capitalisation as part of their business plan submission. This aligns with the RIIO-ED1 Business plan process.

Notional gearing question

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

Gearing should be set after the parameters of the overall price control package have become clear. Any deviation from the RIIO-T1 gearing level should be clearly explained based on evidence of changes to the overall financeability of the RIIO-2 price control settlement.

Notional equity issuance consultation question

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

In principle, we agree that the cost of raising equity should continue to be set as an allowance in the financial model. However, due to the financeability arguments within the consultation and the onus Ofgem intends to put on the companies to take action, like issuing equity, it is vital that the assumptions for costs of equity issuances are correct to ensure that a fair allowance can be set in relation to this activity.

Ofgem should therefore ensure that any move away from the RIIO-1 assumption of 5% issuance cost is clearly understood and backed by evidence.

Furthermore, the timing and size of any equity issuance would be dependent on market conditions, which can change rapidly over time, and thus would have an impact on the cost of the issuance. This consideration may have to be taken into account in the analysis in arriving at the allowance.

Pension funding question

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

We would agree with this proposal. Whilst it may be preferable to receive specific allowances for Admin and PPF costs that are reset triennially, the Transmission element of pension costs is not as significant as Distribution. For instance, the Transmission share of PPF and administration costs was approximately £0.2m for each scheme for 17/18. Therefore, a proportion of any overspend of PPF and Admin costs in totex is never likely to be material for Transmission. Given the materiality issue and that these costs are already treated as part of totex for Distribution, we are comfortable in agreeing with this proposal.

DRS question

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

We agree in principle with Ofgem's proposal to align existing policies for Directly Remunerated Services (DRS) where possible, providing a coherent and consistent approach across all sectors. In particular, a consistent approach should be applied to align the treatment of both costs and revenues of individual activities that fall within the categories of directly remunerated services, for example sole use connections.

Amounts recovered from the disposal of assets question

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

We would propose the treatment of financial proceeds or fair value transfers of assets be aligned with RIIO-ED1 where cash proceeds are netted off against totex from the year in which the proceeds occur. Therefore disposals, within overall totex, will be subject to the Totex Incentive Mechanism (TIM) and the proceeds from disposals will be shared with consumers, subject to the sharing factor. The treatment of the disposals, fair value transfers of assets and associated re-investment should be equal, to ensure consumers, both current and future generations, benefit from the overall net investment.

Ensuring fair returns question

CSQ81. Do you agree with our comparative assessment of RAMs set out in Table 18 in Appendix 4?

Anchoring

With respect to the anchoring proposal, which involves an ex-post review of companies' returns, we do not agree with Ofgem's assessment of this proposed approach. This is a material departure from the longstanding and highly successful regulatory framework for electricity networks in Great Britain. Ofgem itself recognises that it could *"increase uncertainty for investors and run the risk of destroying the good incentive properties of the framework."*[60] From the information we have been given to date, the proposals appear to be inconsistent with previous CMA support for *"the regulatory principle that good performance is not unduly incentivised"*[61] and the importance of investors being able to assess the risks of investing in 'the' company.[62]

We do not agree that the approach has a neutral impact on incentives and believe that the approach would instead materially undermine incentives to achieve cost efficiencies or improved performance. Even the mere possibility that the mechanism could apply may reduce companies' ambitions and attempts to be more innovative and efficient. Also, since rewards from outperformance are harder to predict, but each network company would want to ensure that it had the maximum available opportunities to outperform, companies that are even slightly risk averse would have weaker incentives to submit ambitious and innovative business plans.

Overall the mechanism would undermine investor confidence, as company performance would only be known at end of review (or once Ofgem has agreed to set of industry returns). Debt and equity holders would have little sight of performance or risk, thus increasing uncertainty for them which would make it harder to predict what the outcome will be. This could therefore increase the cost of capital and heighten the risk of companies not being able to access debt markets.

We do not agree that anchoring would reduce risk; instead we believe that it would increase risk substantively as the degree of the adjustment depends on other companies. If one set of companies performed exceptionally either through own effort or an unduly preferable price control settlement the rest of the industry may not earn its allowed cost of capital. The rise in the risk of unanticipated downward adjustments to allowed revenues for companies could also lead to financeability issues.

Further, the mechanism needs to be considered very carefully in light of the wider need for Ofgem to balance competition and collaboration on a specific, case by case basis, i.e. to ensure that companies collaborate in specific cases where it is effective and will be to the benefit of consumers

Sector average sculpting

We do not agree with Ofgem's assessment that the sector average sculpting mechanism has a neutral impact on incentives, risk and collaboration. Similar to the points raised in regards to Anchoring, we believe the mechanism has a negative effect in these areas.

As the adjustment depends on an ex-post review of other companies' returns, uncertainty is increased for companies and investors due to the rivalry between companies, although less so compared to Anchoring – it is therefore harder to predict what the outcome will be for returns and investors would

[60] Sector Specific Methodology Consultation at 11.33
[61] British Gas decision at 5.50
[62] SONI at 6.70/6.74

therefore face considerable uncertainty about the returns they may earn, which might increase the required rate of return.

The competitive dynamic introduced by the mechanism would likely lead to a situation where companies are less likely to collaborate with each other because any assistance a provided by one company to another network might end up hurting it in terms of returns (the higher the outperformance the higher the adjustment). However this would only be the case for companies above the sector average threshold.

Although simpler than Anchoring, the introduction of this sculpting mechanism would still require Ofgem to calibrate the sharing factors that would apply for different amounts of out/underperformance. The calibration needs to be done robustly in order to ensure it delivers value for consumers. This can prove to be a complex exercise.

<u>Sculpted sharing</u>

Although we can only take a fully informed view once Ofgem has decided on the various aspects of RIIO-2, overall, from the information provided to date, we are broadly in line with Ofgem's assessment of the sculpted sharing mechanism. It provides some downside protection for companies and investors, since a greater share of underperformance beyond the pre-defined threshold is shared with consumers (rather than being borne exclusively by investors). The mechanism is specified ex-ante, thus negating the exercise of the ex-post review in order to apply it and can be predicted by network companies and their investors. It resembles existing mechanisms deployed by Ofgem and so should be relatively more straight-forward to implement compared to the other mechanisms considered. It also does not depend on the performance of other network companies, so should be relatively predictable and transparent.

We agree that the mechanism will weaken the incentives for companies to become more efficient have a negative impact on incentives as it reduces the reward for network companies from outperformance.

However, by applying sculpting to output performance, companies no longer face correct marginal reward or penalty, and will not optimise output delivery. The reward/penalty will also be uncertain as will depend on companies overall RoRE performance. Companies may therefore hold back on delivering service quality or output improvements beyond baseline levels where the reward is uncertain. Instead, we consider that any sculptured incentive mechanism should apply to totex element of RoRE only (i.e. exclude output incentives) rather than RoRE in its entirety. Ofgem must also ensure it cross checks any decisions in this area with the wider RIIO-2 measures which it introduces, including the shorter time period.

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

We agree with the removal of the discretionary adjustment proposal. The mechanism would significantly constrain the rewards for outperformance, so would materially weaken companies' incentives to become more efficient. The discretionary and asymmetric nature of the mechanism might lead to an increase in the cost of capital due to increased regulatory risk arising from investor concerns about uncertainty surrounding the way the mechanism would be applied. We also note that the mechanism has the potential to be very complex, as Ofgem would need to be explicitly clear about the process, timing and criteria for when the adjustments would occur. This would increase the administrative burden on Ofgem.

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

In addition to the points raised in our CS82 response, we agree with Ofgem's proposal to not apply a Class 2 approach to the gas and electricity transmission sectors as they have correctly recognised that these mechanisms link return adjustments to the performance of the sector as a whole relative to ex-ante expectations. If applied to ET, these sector average returns adjustments would be heavily influenced by the performance of NGET due to its considerable size relative to SPT and SHE-T.

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

We don't agree that a Class 2 approach should be adopted for the GD sector. See points raised in CS82.

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

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

Our recommendation is that any sculptured incentive mechanism should apply to totex element of RoRE only (i.e. exclude output incentives) rather than RoRE in its entirety. In the design of this sculpting mechanism Ofgem should sculpture incentives to mimic returns in comparable competitive markets. NERA have provided evidence to us where they have derived the return distribution using the constituent companies in the UK FTSE All Share (FTSE AS) Index over the most recent 20 year period. NERA limit their analysis to a 20-year period (1998 to 2017) given data constraints, and to ensure a manageable database, with distributions being reported as 5-year rolling annualised returns.

NERA's analysis shows that, for the market as a whole, the distribution of returns is relatively wide, with upper quartile (UQ) companies earning returns which are 9.5% higher than the median. The corresponding high and low percentiles (25^{th} and 75^{th} are approximately symmetric relative to the 50^{th} percentile.

As well as identifying market returns, NERA also identify return distributions for comparable sectors: utilities and telecommunications. They also calculate distribution for FTSE 250 index to control for size, as most network fall in FTSE 250 category. NERA find that the utility sector has narrowest distribution, with the 75^{th} percentile return being 3.8% higher than the median. The 75^{th} percentile relative return for telecommunications and FTSE 250 is higher at 8.8% and 10.2% respectively. See Table x below.

Table x – 5-year annualised returns relative to median/50th percentile for utilities, telco, FTSE 250 and FTSE AS

Percentile	Utilities	Telco	FTSE 250	FTSE AS
10%	-8.5	-13.4	-16.6	-16.8
25%	**-4.0**	**-6.0**	**-8.3**	**-8.0**
40%	-1.3	-2.0	-3.3	-3.1
50%	0.0	0.0	0.0	0.0
60%	1.2	2.5	3.4	3.2
75%	**3.8**	**8.8**	**10.2**	**9.5**
90%	7.5	27.2	24.0	23.0

Source: NERA analysis based on FTSE All-Share index companies returns downloaded from Bloomberg and FactSet as at September 2018. Utilities and Telecommunications sectors are identified using the Industry Classification Benchmark (ICB) by FTSE.

In the design of the mechanism, network companies should be subject to high incentive rate (e.g. >50-60%) where totex element of RORE lies within inter-quartile (IQ) range, as IQ includes half of all companies. The sculpting inflexion points applied to totex could draw on the utility sector percentile returns (relative to median) from NERA's return distribution analysis.

Drawing on their utilities return distribution results from table x, the IQ range is ca. +/- 400 bps relative to baseline cost of equity, suggesting that the first inflexion point should be at least equal to this level. Incentive rates could be lower at 90th percentile, as very few companies attain such return i.e. +/- 8% relative to baseline cost of equity drawing on utilities index.

These proposed inflexion points applied to totex element of RORE could equally be expressed as a percentage of totex out/underperformance.

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

As highlighted in the above responses, we recommend that any sculptured incentive mechanism should be applied to the totex element of RoRE only.

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

Financial performance should not be included within the scope of return adjustments. Several factors contribute to the ability to outperform in this area; an effective treasury function, market conditions and the network's fundamental business and its financial policies.

Regulated networks which display solid business risk fundamentals and maintain investment grade credit ratings through effective price control management are able to obtain cheaper debt. In the RIIO price controls, the cost of debt allowance is annually updated with reference to the latest iBoxx indices which reflect latest market conditions. That mechanism already mitigates the ability to outperform. Furthermore, as the RAV is depreciated over 45 years, multiple debt tenors must be accounted for to calculate overall outperformance. That complexity is further compounded by intricate financial structures.

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

Unlike the treatment of totex performance through the annual iteration process, the proposed return adjustment mechanisms measure performance over the full price control period. Consequently it would be sensible to treat any adjustment as part of a close-out process.

Achieving a reasonable balance in RIIO-2

RIIO-2 Achieving a reasonable balance questions

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

On the whole, we believe the suite of policy measures proposed are becoming overly complex and go against Ofgem's goal of 'simplification' and in many cases are introducing more risk for licensees and for Ofgem and therefore more cost for consumers. The aggregate effect of Ofgem's various different. proposals equates to a risky package (whereby more risk is placed on the network companies than has ever been in any previous price control).

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

Remove proposals for dynamic/relative incentives as these can never be calculated on a 'like for like' basis and will therefore never result in a fair/accurate result.

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

Yes. Ofgem should review all of its new policy proposals and refine this list into the significant items which are definitely required. As currently proposed, there are too may new and untested policy changes which not only introduce risk, but introduce great complexity.

It is also essential that Ofgem delivers the various items outstanding, which we referred to in our response to the Business Plan Guidance consultation, in order that we can meet the challenging timescales for business plan development.

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

Whilst network companies tend to be considered as relatively low-risk businesses, this is due to the fact that there has been a high degree of certainty on their future revenues. As currently proposed, Ofgem will introduce 'ex-post' mechanisms in addition to significantly lowering base returns; making these companies less attractive than they once were. As electricity network companies are entering a significant transitioning period to support Government's low carbon agenda, such companies must continue to be low risk businesses or consumers will pay more than they need to.

The level of returns indicated by the proposals does not reflect the risks faced by companies. This is obvious when comparing the proposed RIIO-2 Cost of Equity to Ofwat's. Water companies are generally accepted to be less risky than electricity networks, yet water companies have accepted a Cost of Equity that is 100bps higher to Ofgem's current proposal. Please see our responses to the financial section for detail.

More generally, as we've highlighted in relation to the on-going work on the Competition Proxy Model, it is important that if Ofgem does seek to make delivery obligations more firm, it considers how it will ensure that any related investigation or enforcement action is reasonable, proportionate and fair. We would be happy to work further with Ofgem to identify what changes to, for example, its enforcement guidance, might be required. Similarly, it is essential that Ofgem performs a cross check to ensure that any penalty mechanisms which it does seek to introduce would not penalise a licensee for the action or inaction of others which it could not control.

CSQ94. Have we achieved a reasonable balance with our proposals in seeking to achieve an accurate price control with return adjustment mechanisms only being used as a failsafe? Should we instead have a simpler price control and put more reliance on return adjustment mechanisms? & CSQ95. Have we achieved a reasonable balance in our proposals in considering return adjustment mechanisms alongside the expected-allowed return wedge? Should we instead only rely on one mechanism? What additional value would this bring?

We do not believe that the correct balance has been struck as the Return Adjustment Mechanisms are trying to achieve the same objective as the expected-allowed return wedge. Ofgem's Return Adjustment Mechanisms were created in isolation to the UKRN report's recommendation to introduce an 'expected-allowed return wedge'. We do not accept that Ofgem's choice is limited to having either a) both mechanisms or b) a sector wide anchored Return Adjustment Mechanism Ofgem should only rely on one mechanism and must ensure that mechanism is effective, proportionate and in customers' long term interests. .

Whilst we do not support all of the proposed Return Adjustment Mechanisms, we support Ofgem's policy intent to ensure that companies cannot excessively outperform. As we have detailed in our financial section, we support any mechanism which will ensure companies cannot outperform due to any TOTEX underspends which are not due to efficiency.

Companies must still have the opportunity to outperform due to fair efficiencies and good performance, otherwise, we will return to an inefficient 'RPI-X' regime. In any case, any return adjustment mechanism must not include incentives as this will disincentivise companies from performing well (as they will never know what the final target to aim for is, as there will be a moving target). For further detail, please see our responses to the "Fair Return" questions.

Efficiency vs fairness questions

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

We are due to consult with our stakeholders on incentives during March 2019. From this exercise, we hope to establish whether there are any areas that we or Ofgem have not taken into account. We will be able to share any non-confidential feedback with Ofgem. In addition, the current Willingness to Pay surveys which are being carried out will help us confirm which areas are of most value to consumers.

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

Yes – we have a 'four pronged' approach in relation to our stakeholder engagement methodology to insure adequate balance amongst interest groups. Due to this approach, we do not feel that any groups are missing.

I. General Stakeholder Engagement: We are making use of existing, well established engagement arenas and channels to publicise our RIIO-T2 Business planning process and create arenas for information exchange and meaningful feedback. We have created dedicated RIIO-T2 pages of our website and are increasing our use of social media to facilitate more 'accessible' engagement

II. Dedicated Market Research Activities: We have commissioned Explain market research to conduct a number of RIIO-T2 specific strategic focus groups and deliberative workshops with members of the public (including future consumers and poorly/served/vulnerable groups). This activity will build on the UK-wide Willingness-to-Pay research (being conducted across all TO) and tie in with the information discussed/fed back to the TO User Group.

III. Formal Stakeholder Engagement/Representation via our TO User Group: We have carefully recruited for our TO User Group 9 ‘industry experts’ that reflect the broad needs and interests of our stakeholders

Stakeholder Engagement Assurance Process: We are working with SIA Partners to provide assurance and triangulation of the engagement activity and research we carry out throughout the RIIO-T2 process to ensure that we have an adequate balance between interested groups and opportunity for discursive as well as deliberative communication events and activities.

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

Yes – please see response to Q97.

Appendix 5 - Preliminary impact assessment of our proposals

Preliminary impact assessment questions

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

This is not detailed enough given the level of risk associated with not getting the RIIO-2 package right. Each proposal should be stress-tested in detail for each sector. We suggest listing out all policy initiatives for each sector and providing a low to high case financial impact. In addition, it would be helpful to include a bill impact value in order to put this into context for our stakeholders.

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

As above; more detail is still required.

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

We believe that BREXIT and wider political and macroeconomic uncertainty should also be included and the impacts assessed against each policy area.

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

External views from credit rating agencies and investors are particularly important, and these must be reviewed in full. Ofgem must ensure that it takes a balanced approach in reviewing external feedback and does not 'cherry pick' from the relevant good news stories.

In this document we have provided detailed answers to each of the consultation questions posed in the Sector Specific Methodology Document. In preparing these responses, we have followed Ofgem's approach, focusing on the Transmission network but also highlighting areas of similarity or difference with the distribution network. We note that we shall have a further opportunity to engage in how the matters covered by this consultation may apply to our distribution licences when Ofgem develops its proposals for RIIO-ED2.