Annex 1 – Responses to Draft Determinations consultation questions from Ofgem Consultation on RIIO-ED2 Draft Determinations

Overview Document Questions

6. Adjusting allowances for uncertainty

Q1. Do you agree with our proposal to introduce a new funding mechanism for PoLR activities?
DNOs are focussed on the provision of assets and services to facilitate the installation of charge points (as neutral market facilitators) rather than the installation of the chargepoints themselves – which is a competitive activity. If DNOs are to be required to deliver PoLR activities then in addition to the necessary funding being made available, further guidance is required on how DNOs should work with EV chargepoint operators going forwards over the short, medium and long term for any PoLR activities.
Q2. What are your views on our two proposed options, and do you agree with our preferred option of a DRS?
DNOs must be able to recover all costs efficiently incurred in delivering the PoLR activities in a timely manner. WPD agrees with the use of a common funding mechanism across all DNOs.
Q3. Do you agree with our proposal to introduce a re-opener to deal with recommendations from the Storm Arwen review, our proposed trigger and re-opener window?
Given discussions are ongoing between DNOs, Ofgem and E3C on the back of the Storm Arwen report, we do not have clarity yet on the scale of some of the steps we will be required to take. We note in particular Ofgem's statement in para 13.12 about the level of interest in their review of severe weather-related GSoPs which they say could affect delivery timeframes. As such WPD supports the inclusion of a Storm Arwen reopener, the timing of which should factor in the latest Ofgem timetable for the conclusion of all Storm Arwen recommendations.
Q4. Do you agree with our proposal to maintain the RIIO-ED1 High Value Project mechanism and focus it on non-load related HVPs in RIIO-ED2?
Yes we are happy with the proposal to maintain the high value mechanism and to focus this on non-load projects as the LRE UM should adequately cover all load related projects.

Q5. Do you agree with our proposal to remove the RIIO-ED1 smart meter volume driver?
WPD does not support the proposal to remove the RIIO-ED1 smart meter volume driver. Whilst the government target is to complete the smart meter rollout programme by 2025 we are also aware of recent discussions requiring suppliers to commence replacement of installed SMETS1 meters once they have achieve 85%+ rollout of their SMETS meters. Discussions around this programme appear to be at relatively early stages but the replacement of some existing SMETS1 meters with SMETS2 meters may result in the need for further DNO actions, over which we have no control. As such, we consider the smart meter volume driver should remain for RIIO-ED2. Please also refer to our response to Core-Q101.
Q6. Do you agree with our proposed approach for a common materiality threshold being applied to RIIO-ED2?
In designing the RIIO-T2 and GD2 frameworks, Ofgem proposed 'common design parameters' for reopeners with the stated intention that these would also be applied in the ED2 Price Control - it was asserted that the framework for reopeners and the uncertainties they are intended to cater for would be broadly comparable. In DD, Ofgem confirmed its intention to proceed with implementing the common design parameters, with the exception of seeking further stakeholder views on its proposed approach to the Materiality Threshold:

UM parameter	Consultation position
Re-opener application windows	Bring forward re-opener application windows from May to January (apart from the first year where it will be the last week of April 2023 lasting one week). Reduce re-opener application window from one month to one week (last week of January).
Application requirements	Provide additional detail and guidance where possible in licence conditions and guidance.
Authority triggered re-openers	The decision whether the Authority can trigger a re-opener at any time during the price control will be made on a case-by-case basis.
Aggregation	To not include an aggregation process for re-openers to meet the materiality threshold.
Materiality threshold	For each individual re-opener application, set a materiality threshold such that we propose to only adjust allowances if the changes to allowances resulting from our assessment, multiplied by the TIM incentive rate applicable to that licensee, exceeds a threshold of 1% of annual average base revenues (as set out in Final Determinations).

Ofgem presents two primary arguments in support of its proposal for a Materiality Threshold of 1% of annual average base revenues (as set out in the Final Determinations):

Firstly, Ofgem believes that network companies should be able to manage non-material variations in expenditure within their wider allowances. Ofgem also states that it does not believe that it is efficient for the regulator to assess many small value claims from the companies for additional funding.

Secondly, Ofgem argues that given that companies should be able to manage non-material variations, a threshold needs to be set at which point consumers will share additional costs. It has concluded that this should be set at 1% of annual average base revenues (as set out in Final Determinations). This figure is calculated after application of the TIM i.e. with a TIM of 50%, a variation of 2% of base revenues would be therefore be necessary prior to a re-opener meeting the materiality threshold.

We do not consider Ofgem has provided any rationale as to why they are proposing to set the threshold at 1% of annual average base revenues in RIIO-ED2, in particular given their recent decisions in RIIO-T2 and GD2 to set the threshold at 0.5%

In the Draft Determinations consultation for RIIO-T2/GD2, Ofgem proposed a materiality threshold of 1% of baseline revenues, combined with 'aggregation' to mitigate the risks of under-recovery by the companies. At Final Determinations, Ofgem modified its proposal and settled on a lower threshold of 0.5% offset by there being no aggregation.

Ofgem, and many of the consultation respondents, felt that this combination of a lower threshold with no aggregation provided adequate protection whilst still encouraging efficient delivery by the companies. It had the additional benefit of avoiding further complexity being introduced through a set of rules being required to govern aggregation.

Given this conclusion, it is not clear why Ofgem has not carried across the 0.5% threshold as one of its design parameters and is consulting again on the use of 1% particularly given that, for RIIO-ED2, aggregation has already been ruled out. This is particularly the case given that it is an element within a Common Design Parameter set which is designed to be applicable across RIIO2 and given that the arguments as laid out by Ofgem above are not specific to the electricity DNOs or the nature of the activities they carry out but rather equally applicable in the case of Transmission and the GDNs. Indeed, the very nature of electricity distribution means the individual works are generally of smaller scale and therefore less likely individually, or in discrete numbers to trigger the breaching of a re-opener threshold as compared for example to individual volumetric and other drivers at transmission where the size of a single project can be much more significant.

The precedent set in RIIO-T2/GD2 is clear and should be followed in RIIO-ED2. In the event that Ofgem were to choose to deviate it would be necessary that Ofgem clearly explain the rationale and why it believes that applying such an approach would accord with the discharge of its duties and why it has failed to follow through on what was intended to be a 'common parameter'.

WPD is of the firmest view that the materiality threshold now be amended. In particular failure to amend that which is now proposed would result in:

- Higher levels of overall risk than have been specifically accounted for in the setting of the WACC and/or in the choice of point estimate to manage risk exposure and to consider financeability and financial resilience;
- Increased asymmetry in the risk profile faced by DNOs such as WPD which is not reflected in the choice of point estimate in the determination of the WACC

and, which in combination with other asymmetries within the package, calls into question the use and application of the CAPM as a basis for the setting of the cost of equity;
- A set of incentives which will drive risk aversion and which incentivise DNOs to not undertake works which are the subject of re-opener mechanisms on the basis that there is less certainty that such costs will be recoverable as a result of a significantly higher materiality threshold.

We briefly explore each in turn.

Increased Risk as a Result of Significantly Greater Exposure

A 1% threshold exposes DNOs to greater levels of risk, and variation in expected returns, relative to the GD and T companies. Insofar as this risk is correlated to risks within the macroeconomy – and given that a number of the UMs relate to activity around domestic policy and Net Zero, this seems highly probable – then it equally gives rise to higher levels of systemic risk which should be compensated through higher beta estimates within the cost of equity.

The use of a threshold is justified on the grounds of companies managing non-material variations in costs. However, for WPD, over £27m could be spent under any single re-opener without it being triggered. This equates to a worst-case theoretical scenario of up to £270m of unrecovered costs, given that there are 10 reopeners in the proposed framework – a figure which is unambiguously material.

Furthermore, a £27m downside risk on any individual incentive prior to triggering the re-opener is equivalent to 0.74%[1] RoRE[2] and so the reward from several financial incentive schemes could be eliminated through no fault or under-performance of WPD.

Nowhere is it clearly set out by Ofgem how it has taken or proposed to take this additional scale of risk exposure into account either in terms of adjustment to beta where the risk is correlated to wider and non -diversifiable factors or as part of the choice of point estimate of WACC or of other revenue parameters within the framework.

Increased Asymmetry in the Risk Profile

Given Ofgem's position as articulated in the Draft Determinations[3] that "*We are proposing to set baseline totex allowances for the DNOs only where we are satisfied on the need for and certainty of the proposed work, and where there is sufficient certainty on the efficient cost of delivery"* the additional risk as set out above is largely if not entirely asymmetric in nature. That is the risk of non-recovery under the materiality threshold is related to the potential incurrence of additional expenditure not recovered and there is no suggestion that Ofgem has "aimed up" or applied a margin in the context of operational costs to take account of this risk.

Given this asymmetry there is effectively a negative skew in the expected distribution of returns and the mid-point or expected P50 position in terms of the level of returns as a result is materially lower. Again, there is no evidence that Ofgem has considered this, nor the effect that such negative skew (indeed the distribution is effectively

[1] The RoRE % has been calculated using the cap and collar financial values for those ODI-Fs quoted in the Draft Determinations Finance Annex where these have been expressed as a RoRE %.
[2] Compare if you will the absence of analysis of the effect of this relative to the consideration of effect of individual ODI incentives measured against RORE for the achievement and delivery of value adding outcomes as part of the overall package.
[3] Ofgem RIIO-ED2 Draft Determinations Overview document, paragraph 6.2

truncated in relation to this point) has on the applicability of CAPM which is reliant on symmetry in the underlying distributions.

This asymmetry is further exacerbated by the fact that even when triggered a number of the uncertainty mechanisms are structured in a manner where there is a further asymmetry or truncation in the distribution and the licensees can at best recover their costs and have the potential to receive less than full cost recovery due to the application of discretion or mis-identification by Ofgem of the level of costs which is ultimately efficient.

Whilst both these asymmetries have existed in the past – although just because they have existed in the past does not necessarily mean they are appropriate – the scale of monies and number of re-openers as exemplified through Ofgem's assessment of the financing and tariff impact in the financeability sensitivities is now so much greater

Impact on Incentives and Risk Aversion in Incurrence of Costs

The introduction of a higher materiality threshold also distorts incentives and could give rise to a level of risk aversion or aversion to the incurrence of expenditure under Uncertainty Mechanisms which runs counter to the protection Ofgem intends such mechanisms to afford consumers.

If a licensee believes that it will not be in a position to recover costs through undertaking an activity it will have the natural incentive to seek that the activity not in fact be undertaken. To not undertake the activity will result in any loss in net benefits or NPV value which would have arisen for consumers as a result of it being undertaken.

Given the possibility of exposure to significant costs which cannot be recovered, one should consider whether this could have a distorting effect on decision-making. We would argue that network companies may tend towards a more risk averse stance on activities covered by a re-opener, given that a high threshold makes it less likely that costs will be able to be recovered. This is unlikely to be of benefit to consumers who could face delay or be denied investment where the business case is more marginal.

Secondly, the extensive use of re-openers, in preference to providing ex-ante allowances, builds asymmetry into the overall package. It is almost guaranteed that companies will generate expenditure which cannot be recovered from customers, as the expenditure will not be sufficient to trigger the Uncertainty Mechanism – itself a downside risk. Even where that threshold is reached, companies will at best receive their actual costs without the opportunity to outperform which is inherent to an ex-ante allowance.

Even insofar as the risks can be diversified, they still nonetheless expose the company to greater potential downside which would warrant a higher choice of point estimate within the overall cost of capital or other financial protections to help ensure financeability and financial resilience.

It is all the more surprising therefore given this material difference in terms of the treatment of the DNO from the GDNs that the Ofgem position at Draft Determination is that DNOs are exposed to precisely the same level of systemic risk as the gas distribution companies, with the proposed beta being identical to that in T2/GD2 to three decimal places. No explanation is provided by Ofgem as to why it believes this to be the case.

In attempting to modify this proposal so as to give fair, but not overly generous protection to both companies and consumers, there are two options open to Ofgem: • Introduce significant aggregation across the UMs – this is not favoured, as we believe that Ofgem's original decision that it would introduce further complexity was the correct one. • Align the ED2 framework with that used in T2/GD2 and set a materiality threshold at 0.5% of average annual baseline revenues. WPD is of the firm view that this change is necessary and would be consistent with the application of the common design parameters. As a complementary measure, Ofgem could increase the use and size of *ex-ante* allowances. There are a number of strong reasons for doing so, particularly in relation to expenditure associated with Net Zero and transformation of the Energy sector which are described elsewhere in this consultation response. However, specifically with respect to the materiality threshold, it would reduce the risk of the re-openers needing to be triggered which would increase the agility and responsiveness of the companies in delivering the relevant services, whilst also acting to reduce the regulatory burden on both Ofgem and the companies which will result from the preparation and assessment of re-opener submissions. Furthermore, we believe that this additional measure is also necessary over and above a simple reduction in the threshold given the greater asymmetry of risk which exists as a result of the nature and scale of the uncertainty mechanisms in ED2 relative to GD2 & T2. If Ofgem chooses not to revise down its threshold and/or provide additional allowances, then it is duty-bound to recognise the additional risk that it is placing on the network companies and amend the cost of equity upwards to compensate.

9. Approach to the Totex and Business Plan Incentive Mechanisms

Q7. Do you agree with our view that all the DNOs have passed Stage 1 of the BPI?
We welcome Ofgem's pragmatic approach with regard to the application of Stage 1 of the Business Plan Incentive especially with regard to the assessment of materiality for minor omissions. Overall we agree with Ofgem's view that all DNOs have passed Stage 1 of the BPI.
Q8. Do you agree with our overall approach regarding treatment of CVP proposals?
We are broadly supportive of the approach that Ofgem has taken as specified in paras 9.45 to 9.70 of the RIIO-ED2 Draft Determination – Overview Document. However there is no detailed guidance on how a DNO exceeds minimum requirements or recognition of the stakeholder support for the CVPs. Consumer Value Propositions (CVPs) provide DNOs with an appropriate channel for innovating programmes to go beyond minimum requirements and deliver activities which consumers value as part of the incentive based regulatory framework. It is important that the framework for approving and rewarding CVPs is applied

consistently and robustly. In the Business Plan Guidance, Ofgem provided a range of criteria that it would specifically take into consideration for accepting CVPs.

However, no detailed criteria were set out for how to determine whether an activity exceeded these minimum standards. In order to provide evidence to support our CVPs, and to further assess their acceptability we have employed three tests to assess whether or not the CVPs as set out are over and above the minimum requirements and business as usual:

- Test 1 – Exceeds Minimum Specified Obligations: Is the activity in addition to or in excess of what is described as minimum in the Business Plan Guidance document?
- Test 2 – Represents Incremental Activity over and Above RIIO-ED1: Is the activity something that was already being carried out by WPD in RIIO-ED1?
- Test 3 – Goes above and beyond the average equivalent activities in the Sector; Do any other DNOs propose to provide the same level of service in their baseline proposals?

We believe that if CVPs are accepted then it is important they are accepted with a reward framework as set out in the Business Plan Guidance. But we equally believe such reward mechanisms must be robust and there should be no questions of customers paying for a reward where net benefits are not delivered. Where Net Benefits are delivered customers will ultimately benefit from the delivery.

10. Increasing competition

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

We agree with your position on early and late competition.

As per our RIIO-ED2 Business Plan, we support competition in electricity distribution wherever it can deliver benefits for consumers. We will continue to explore, beyond traditional solutions, ways to minimise cost through innovation and digitalisation, exploring multiple options, facilitating non-network solutions and competition.

Under Early Competition, we do not have any specific projects identified that have the potential to exceed the £50m threshold identified for early competition in RIIO-ED2. However, recognising the ESO's proposed early competition assessment of New, Separable, and Certain, in our Business Plan we have identified a project suitable for running through an early competition process to understand how the ESO model might be adapted to provide benefits on the distribution network.

Our review of the outcome of this project can hopefully be considered alongside Ofgem's assessment of whether it is in the consumers' interests for the model to be applied to the ED sector once the Early Competition Model is sufficiently developed in the ET sector.

Similarly for late competition we do not have any projects in our RIIO-ED2 plan that either exceed, or have the potential to exceed the £100m threshold for Late Competition.

11. RIIO-ED2 in the round, post appeals review and pre-action correspondence

Q10. Do you have any views on the proposed scope of the FDQ process and pre-action correspondence, including on the proposed timing for sending such to Ofgem?
In the Draft Determinations, Ofgem makes a number of proposals relating to the regime for appealing its price control decisions to the Competition and Markets Authority ("**CMA**"). We do not agree with these proposals, which are not consistent with the appeals regime and the CMA's decisions and guidance. *Pre-appeal engagement* As per our Response to Ofgem's RIIO-ED2 Sector Specific methodology consultation in October 2020, if we are considering an appeal we will look to conduct pre-appeal engagement with Ofgem in a manner appropriate in the circumstances and to the extent feasible in practice. However, we continue to believe that the proposal for a pre-action correspondence stage between the publication of the Final Determinations and the deadline for a CMA appeal is unworkable in practice, in particular given Ofgem's expectation that companies should identify the scope of any such appeal (including the alleged errors and any interlinked aspects) in sufficient detail. The detail and complexity of the Final Determinations means that it takes licensees significant time to review and understand the impact of the Final Determinations, which will necessarily affect how swiftly and in what detail any prospective appellant could issue pre-action correspondence. Furthermore, the extent of Ofgem's proposals clearly goes beyond the expectations of the CMA as the appeal body. The CMA has launched a consultation for amendments to its own energy licence modification appeals guidance.[4] In its draft guidance, the CMA encourages a prospective appellant to "*inform*"[5] the relevant authority that it is bringing an appeal – it does not suggest the need to engaged in detailed pre-action correspondence as contemplated by Ofgem in the Draft Determinations. A similar comment is made with respect to the FDQ process. As outlined above, the detail and complexity of the Final Determinations impact the speed at which licensees can identify errors and meaningfully engage with the FDQ process. Furthermore, the CMA's draft amendments to the energy licence modification appeals guidance[6] contemplates that such a process should be limited to "*errors that the prospective appellant would reasonably expect that the Authority may be in a position to correct without argument".*[7] We note that, in practice, there may be genuine uncertainty as to whether a decision is a genuine "error" or rather a deliberate policy decision taken by Ofgem that may need to be appealed by the company. This may in particular be the case for "material methodological errors", which Ofgem contemplates being raised as part of the FDQ process. *Post-appeals framework* As explained in our prior submissions,[8] we do not agree with Ofgem's proposal for a post-appeals framework. The consequences of any appeal made to the CMA should

[4] Consultation published 12 July 2022 and which closed on 9 August 2022.
[5] Energy Licence Modification Appeals: Competition and Markets Authority Guide, paragraph 3.12.
[6] Consultation published 12 July 2022 and to be closed on 9 August 2022.
[7] Energy Licence Modification Appeals: Competition and Markets Authority Guide, paragraph 3.13.
[8] See: WPD's Response to CSQ1 of Ofgem's RIIO-2 Sector Specific methodology consultation in March 2019, WPD's Response to Q40 of the RIIO-2 Draft Determinations consultation in September 2020, and WPD's Response to OVQ1 of the RIIO-ED2 Sector Specific methodology consultation in October 2020.

remain self-contained within the CMA appeals framework. Ofgem already has the ability to explain potentially interlinked aspects of any appeal under the existing appeals mechanism and during the CMA appeal and the CMA has the power to account for interlinkages as part of any relief that it orders. It would be inappropriate for Ofgem to carry out additional adjustments to parts of the price control arrangements that were not covered by a CMA appeal as part of any post-appeal review.

Ofgem's recognition that the licenses of non-appealing licensees should not be modified following a successful appeal is welcomed. However, we strongly disagree with Ofgem's contention that a "non-appealing" licensee should be defined as a company that does not appeal any aspect of Ofgem's decision. Just because a licensee has appealed a specific aspect of the FD, that is not a sufficient basis for Ofgem to implement a post-appeal adjustment for aspects of the price control that it did not appeal and are not interlinked to its appeal (and where it therefore has not had direct involvement in the context of an appeal to the CMA of those aspects). Licensees do not appeal a price control decision 'in the round', they appeal particular aspects where Ofgem has made a sufficiently material error regarding their own individual determination. Were Ofgem to roll out changes to licensees that did not appeal a particular aspect of the price control, this would materially undermine the appeal framework and could cause harm from a public policy perspective.

Interlinkages

Generally, we consider that Ofgem's proposal to consider the RIIO-ED2 package "*in the round"* is considered appropriate. However, we do not consider that the broad and non-exhaustive categories of interlinkages identified by Ofgem in the Draft Determinations are consistent with how the concept of "interlinkages" should be viewed in the context of a CMA appeal, nor in line with the CMA's view of how regulators should explain such interlinkages and the reasons for them. We do not propose to comment in more detail on the particular interlinkages set out in the Draft Determinations but note that Ofgem has sought to expand and widen those alleged interlinkages compared to its position in GD2 and T2,[9] which suggests that it has sought to be as broad as possible without providing reasons as to why ED2 warrants a different approach to the GD2 and T2 price controls.

12. Access and Forward-looking Charges Significant Code Review

Q11. Do you agree with our proposal to not introduce a specific uncertainty mechanism to manage the impact of the Access SCR (and address it through the LRE mechanisms instead)? Please explain why.
Yes. We agree with the proposal in principle, but are concerned that at the current time, the lack of details on how this mechanism will operate means it is unclear at how effective it would be compared to the certainty of ex-ante allowances.

[9] See, for example, the insertion of additional interlinkages at pages 91 to 94 of the ED2 Draft Determinations compared to pages 141 to 145 of the RIIO-2 GD2/T2 Draft Determinations, in particular the broad interlinkage category in relation to the approach to cost assessment: "*Wider output and uncertainty mechanism package"* (page 94). See also more generally the increased emphasis on the interlinkages analysis as an 'in the round' assessment (at, for example, page 87 RIIO-ED2 Draft Determinations).

We are in favour of reducing the complexity of the number of controls for RIIO-ED2 and hence the commonality between the uncertainty of LRE and uncertainty of SCR impacts is strong, so we support the combination of these into a single mechanism.

However, there are many impacts of the SCR that are now very certain and these need to be reflected in changes to the ex-ante allowances proposed in the Draft Determination. There will also be an increased range of volumes of reinforcement activity which will be apparent in RIIO-ED2 and any caps associated with volume drivers need to be cognisant of this.

Also the proposals for the UM do not cover the indirect cost increases required to support the increase of connections due to the SCR changes, so sufficient allowances must be upfront to fund this activity.

Core Methodology

2. Embedding the consumer voice in RIIO-ED2

Core-Q1. Do you agree with our proposals for the enduring role of the CEG?
Overall we agree that all DNOs should retain a successor group to the CEG which provides independent scrutiny and ensue that customers' and stakeholders' requirements are being addressed by the DNO. WPD has committed to doing so, including updating the terms of reference to evolve the CEG to fulfil an enduring role as a RIIO-ED2 Business Plan Delivery Challenge Group, including crucial responsibilities to: Hold WPD to account for its delivery of its RIIO-ED2 Business Plan core commitments and provide independent assurance of its results (including performance reports and regulatory reporting).
Core-Q2. Do you see value in the CEGs working together to deliver more coordinated and comparative reporting on some of the DNOs' Business Plan commitments?
Yes. We consider the achievement of greater consistency between DNO CEGs to be essential. This should be achieved through closer working together and will require Ofgem input to ensure DNOs are being held to consistent standards and facilitation to ensure CEG chairs share insight and best practice. The various CEG Business Plan reports revealed inconsistencies in the assessment approach, with some DNOs earning praise for levels of performance for which others were criticised. Examples include the volumes of stakeholders engaged, the depth and quality of that engagement and its effectiveness in shaping the core commitments contained in final Business Plans. Some DNO CEGs stated they took predetermined commitments to stakeholders to simply seek their support and minor revisions, whereas others, such as WPD, pursued a co-creation approach starting from a blank sheet of paper. However, CEG reports failed to account for these differences in their final judgements and therefore oversaw very different levels of stakeholder influence over decision making. WPD, for example, was held to a much higher threshold for commitments to be deemed 'well justified' than other CEGs, with a requirement to meet six detailed criteria (these included: appropriateness of DNO action, consideration of alternatives, cost benefit analysis, stakeholder support, price control mechanisms and independent assessment.) This lack of consistency has led to very different DNO performances in relation to enhanced stakeholder engagement and the best interests of consumers across the UK would be better served if the standards CEG's used to assess companies were more consistent and we believe Ofgem has a role to play to independently arbitrate to ensure this is the case. Within RIIO-ED2 there are other groups planned, such as the DSO Performance Panel, which will assess performance against Business Plan commitments. The interaction and scope of these need to be considered and it may be necessary to define the roles and responsibilities to avoid the risk of duplication of activity.

3. Networks for Net Zero

Core-Q3. Do you agree with our proposal to adjust allowances to £2.68bn to account for the concerns highlighted by our assessment?
No. We maintain that WPD should be funded to the level associated with our "Best View" which is more reflective of what will happen in RIIO-ED2 with regard to the take-up of low carbon technologies. Our "Best View" has been built up from the DFES and tested with our 130 local authorities and hence is the most appropriate forecast as to what is likely to happen in our region. This will allow for transparency with regard to the bill impact for our customers and ensure that we can effectively invest in the network to enable our stakeholders to achieve their net zero ambitions. We acknowledge that there is a delta between the cost impacts of the predicted load growth as identified by the DNOs and Ofgem and agree customers should be protected from higher costs than necessary. The impact of network spending needs to be transparently messaged to customers and DNOs need to be mobilised to undertake investment at the appropriate levels. There are mechanisms which can adjust allowances to deal with uncertainty which will ensure that the customer does not pay for unnecessary investment in the network or lack of investment. We do not agree with the proposal for Ofgem to benchmark load related expenditure on the System Transformation scenario for two reasons. Firstly, the System Transformation scenario relies heavily on wider centralised energy system developments, which have not been maturely signalled by Government nor does the System Transformation scenario deliver the 600k annual heat pump delivery by 2028 referenced in the Government's 10 point plan, as such we believe the proposed reductions will under-deliver against Government policy. Secondly, DNOs have all been asked to consider multiple scenarios and pathways when submitting their Business Plans, particularly with a view to optimising the option value of future investment under different pathways.
Core-Q4. Do you agree with our proposed secondary reinforcement volume driver and LV services volume driver and the associated controls?
The proposed secondary reinforcement capacity and volume driver is well placed to support the agile and efficient delivery of the LRE associated with it. Whilst changing volumes of delivery will be appropriately funded through this mechanism, it does not alter the closely associated indirect (CAI) and business support (BS) costs. We propose an additional uplift to the unit costs to cover additional CAI and BS costs where costs are in excess of the ex-ante allowances. Whilst we recognise the consumer protection a cap on activity achieves, the calibration of this against the CCC balanced pathway must ensure all pathways to net zero are not foreclosed. We also recognise the benefit of being able to revise or remove the cap during mid-period review. We welcome the position to have the LV services volume driver operate across both proactive and reactive activities and we agree with the proposed mechanism for the LV services volume driver. Although we have concerns regarding the proposed unit costs.

By using expert view asset replacement unit costs, Ofgem is making an assumption that proactive service unlooping is equivalent to asset replacement service work. This is not the case. There are various complexities about unlooping which are not encountered under asset replacement, such as the disconnection of cable between properties, installation of a new cable route, potential changes to the service position due to accessibility for the new dedicated service. For this reason it is inappropriate to use the asset replacement unit cost. The benchmarking for proactive services should use RIIO-ED2 industry median unit costs as per the other secondary reinforcement cost areas. We also note there is no allowance associated with fuse upgrades which we presume to be an omission.
Core-Q5. Do you agree with our proposed LRE re-opener?
No. Whilst the proposed re-opener shows some promising aspects, we do not believe it will provide the agility needed to support our customer's ambitions to net zero. Our intensive stakeholder engagement has set forward a Best View which meets the capacity required by our customers in the appropriate timescales. It remains unclear that there will be the appropriate level of agility enabled by the re-opener to flex investment to customer requirements. There is also a proposal from Ofgem to have a materiality threshold of 1% above base revenue post the application of the Totex Incentive Mechanism (TIM) which equates to a 2% of base revenue for an uncertainty mechanism trigger point before the application of TIM. This is a variation from the materiality threshold level of 0.5% post TIM for the GD&T price control. We cannot understand why the RIIO-ED2 price control has not been set at 0.5% of base revenue post TIM. We also feel that this re-opener should be able to be triggered by either the DNOs or Ofgem. Currently the re-opener can only be triggered by Ofgem but we feel that the DNO should be able to trigger it in order to react to our stakeholder's requirements in a timely and effective manner.
Core-Q6. Do you agree with our proposed approach to the Net Zero re-opener?
The concept of a Net Zero re-opener is welcome but further work is needed to successfully calibrate the mechanism and understand any potential for overlap. However it is not clear if a separate mechanism is required, given the numerous other mechanisms already proposed in the price control. Mechanisms to cover wider government policy changes are sensible, particularly to cover cross gas and electricity system changes. There is also a proposal from Ofgem to have a materiality threshold of 1% above base revenue post the application of the Totex Incentive Mechanism (TIM) which equates to a 2% of base revenue for an uncertainty mechanism trigger point before the application of TIM. This is a variation from the materiality threshold level of 0.5% post TIM for the GD&T price control. We cannot understand why the RIIO-ED2 price control has not been set at 0.5% of base revenue post TIM.

We also feel that this re-opener should be able to be triggered by either the DNOs or Ofgem. Currently the re-opener can only be triggered by Ofgem but we feel that the DNO should be able to trigger it in order to react to our stakeholder's requirements in a timely and effective manner.
Core-Q7. Do you agree with our proposed approach to the value of the SIF?
No. We are disappointed that the level of funding available under SIF was not larger in light of the challenges facing the UK to achieve net-zero goals. If this level is maintained at final determination, we agree that the value of the SIF will need to be reviewed during the price control period and enlarged when justified. Whatever the level of funding, WPD will play a leading role in improving the SIF process by working closely with other LNOs and UKRI. LNOs are better positioned than Ofgem and Government to understand the needs of our customers, the network and overall energy system. So far SIF lacks the agility needed and originally envisaged.
Core-Q8. Do you agree with our proposed approach to weighting SSMD criteria and benchmarking RIIO-ED2 NIA requests against RIIO-ED1?
No. WPD acknowledge that Ofgem's overall approach is consistent and that it considers important criteria such as undertaking innovation in BAU, rolling out innovation, applying best practices and monitoring benefits. However, it omits important aspects such as the level of ambition for innovation and how culturally embedded innovation is within the DNO. These aspects were strongly emphasised by our stakeholders and the CEG as key objectives. Additionally, we would disagree with the blunt scoring of companies against the assessed criteria. The "all or nothing" scoring against each aspect is unfair. It is highly unlikely that any company has done nothing to score zero against a criteria, hence the methodology is flawed and unreasonable. We would therefore suggest that Ofgem add to the number of criteria and provide for a sliding scale within each where there are opportunities for improvement back by evidence and proper justification. Cutting allowances based on the current methodology would send a signal to DNOs and stakeholders that innovation on behalf of customers is of a lower priority than in RIIO-ED1. Further, by switching the emphasis on using innovation to drive business as usual benefit under the TIM will mean DNOs will be more minded to be innovative in areas that drive efficiency or leverage incentive mechanisms in the shorter term. Whilst we agree this is important behaviour to foster, it should be in addition to broader innovation in support of longer term net zero, sustainability and customer solutions.

Core-Q9. Do you agree with our proposed approach to setting NIA allowances?
No. As outlined in our response to Core-Q8, we do not agree with the proposed approach. Introducing step cuts in the NIA funding is not appropriate as it discourages DNOs from running low TRL innovation. Through our extensive stakeholder engagement, we see our customers continuously requesting us to focus on the delivery of Net Zero for them, have a high ambition and be world leaders in innovation. Additionally, we do not agree with Ofgem's approach of providing NIA only at a level equivalent to three regulatory years as this will significantly restrict the DNOs' ability of planning, resourcing and delivering their NIA Innovation programmes. This will lead to a reduced number of NIA projects being run and the types of projects chosen will be limited to those that fit the relevant costs and timescale restrictions rather than projects that can create best value to customers.
Core-Q10. Do you agree with our proposal to allow DNOs to carry over any unspent NIA funds from the final year of RIIO-ED1 into the first year of RIIO-ED2?
Yes. We agree with the proposed approach and would welcome a Direction to this effect as soon as possible. This will allow us to mobilise new projects of a longer duration than the current 6 months.
Core-Q11. Do you agree with our proposed approach for the Annual Environmental Report ODI-R?
Generally WPD are in agreement with the proposed approach for the Annual Environmental Report ODI-R. However we have concern regarding the following; • Core Methodology document refers to '*methodologies approved by Ofgem'* it is not clear if these are individual DNO methodologies or common methodologies agreed and adopted by all DNOs. If it is the former how will Ofgem ensure consistency and comparability between DNOs? If it is the latter then Ofgem need to explain how they intend to support and facilitate a collaborative approach to ensure that common methodologies in the following areas are appropriate and fit for purpose prior to the start of RIIO-ED2; - Embodied carbon - BCF – Scope 3 emissions (Categories 1 -15) - SF_6 - Biodiversity net gain
Core-Q12. What are your views on the proposed mid-period review on DNO environmental performance and their progress to targets?
The benefit and reasoning behind the proposed mid-period review on DNO environmental performance is unclear. The Annual Environmental Report (AER) will be published every year with clear up-to-date progress against the EAP commitments and baseline requirements being

demonstrated. The EAP will also provide narratives on performance to date along with expected future performance throughout the course of RIIO-ED2 and detail risks or opportunities which may either encumber or advance performance in key areas.

In our opinion the requirement of a mid-period review would provide no greater detail on performance and progress against targets than what would already be provided for in the AER. Furthermore it is unclear how mid-period targets would be established as progress against commitments may differ throughout RIIO-ED2, for example the roll-out of EV fleet may be weighted towards the end of the period – how would Ofgem account for fluctuations in progress, which may not be within the control of the DNO throughout RIIO-ED2?

The requirement to report on mid-period progress would create an additional administrative burden on DNOs whilst providing no demonstrable benefit to stakeholders, it would provide no additional information to that already presented in the AERs.

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

Our responses to all of the specific elements detailed in the question are below:

Reducing Business Carbon Footprint (BCF): We do not agree with the consultation position with regard to the electrification of the fleet – we are proposing to replace 89% of our small vehicle fleet with non-carbon alternatives by 2028 based on stakeholder driven requirements and Ofgem has rejected this level of electrification which puts our net zero ambition to be carbon neutral by 2028 in jeopardy. Further details are included in our responses to WPD-Q3 and WPD-Q4 of this consultation document.

Reducing Building Energy Use: We agree with consultation position that baseline funding for these projects is subject to submission of evidence to address concerns regarding SLC 43B

EVs and Charging Infrastructure: We do not agree with the consultation position with regard to the electrification of the fleet – we are proposing to replace 89% of our small vehicle fleet with non-carbon alternatives by 2028 based on stakeholder driven requirements and Ofgem has rejected this level of electrification which puts our net zero ambition to be carbon neutral by 2028 in jeopardy. Further details are included in our responses to WPD-Q3 and WPD-Q4 of this consultation document.

Carbon offsetting or removal: We agree with consultation position which requests that WPD provides additional information on carbon offsetting which we have done in our response in Core Methodology - Appendix 1 EAP Proposals - A1.43 Carbon offsetting or removal.

Sulphur hexafluoride (SF_6): We agree with consultation position, however a collaborative common methodology on SF_6 reporting should be established to ensure comparability and transparency amongst all DNOs.

Electricity distribution losses: We agree with consultation position.

Embodied carbon/Supply chain management/Resource use and waste:

We agree with consultation position, however a collaborative common methodology on reporting embodied carbon/supply chain management and resource use and waste should be established to ensure comparability and transparency.

Biodiversity and/or natural capital: We agree with consultation position, however a collaborative common methodology on biodiversity/natural capital reporting should be established to ensure comparability and transparency.

Fluid-filled cables: We agree with consultation position, WPD's response to the additional information request raised in Appendix 1 of Core Methodology document is provided Core Methodology - Appendix 1 EAP Proposals A1.34 Fluid-filled cables

Noise pollution: We agree with consultation position.

Polychlorinated biphenyls (PCBs): We agree with consultation position.

Core-Q14. Do you agree with our proposal to withdraw the Environmental Scorecard ODI-F for RIIO-ED2?
We agree that the obligations under the AER are the appropriate drivers for activities to reduce the environmental impacts arising from the networks as well as to deliver on wider decarbonisation objectives. Furthermore we agree with the reasons stated within the Core Methodology for the withdrawal of the Environmental Scorecard ODI-F.
Core-Q15. Do you agree with our proposed approach to design of the Environmental Re-opener?

Yes.

We agree with the proposed approach to the design of the Environmental Re-Opener.

Environmental and biodiversity legislation is changing and evolving rapidly and by broadening the scope of the Re-opener to incorporate legislative changes in all areas of baseline requirements allows DNOs to address changes in environmental legislation that would require specific material action to ensure compliance.

However there is also a proposal from Ofgem to have a materiality threshold of 1% above base revenue post the application of the Totex Incentive Mechanism (TIM) which equates to a 2% of base revenue for an uncertainty mechanism trigger point before the application of TIM. This is a variation from the materiality threshold level of 0.5% post TIM for the GD&T price control. We cannot understand why the RIIO-ED2 price control has not been set at 0.5% of base revenue post TIM.

We also feel that this re-opener should be able to be triggered by either the DNO or Ofgem. Currently the re-opener can only be triggered by Ofgem but we feel that the DNO should be able to trigger it in order to react to our stakeholder's requirements in a timely and effective manner.

Core-Q16. Do you agree with our proposal for addressing PCB contamination in PMTs through a volume driver in RIIO-ED2?
WPD generally agree with the principle of a volume driver for addressing PCB contamination in pole mounted transformers, subject to development and review of detailed proposals. We look forward to working with Ofgem to develop appropriate metrics for volumes and unit costs. Further detail is provided in our response to Core-Q90.

4. Supporting a smarter, more flexible, digitally enabled energy system

Core-Q17. Do you agree with our proposal for implementing a Digitalisation Licence Obligation?
Yes. WPD believes that ensuring data and digitalisation has the correct level of prioritisation across the energy sector is key and an appropriate licence condition can be an effective mechanism to deliver this. We are already, as noted in the consultation document, 'voluntarily adopting' the digitalisation licence condition, whereby we have regularly updated our DSAPs and ensured that we effectively deliver aligned to the Data Best Practice principles. However, we would welcome more guidance on how the licence condition will capture how and in what format a DNO is measured and deemed to be 'complying with the Data Best Practice principles', specifically where there is whole system collaboration required.
Core-Q18. Do you agree with our proposal to have staggered publications of Digitalisation Strategies between RIIO-ED2 and RIIO-2 licensees?
Yes. There is no concern from WPD regarding staggered publications of strategies between licensees. We expect strategies to be enduring publications to deliver an agreed vision. There are already effective collaborative forums between all RIIO-2 licensees, principally ENA's DDSG, to ensure strategies, aims and objectives are effectively aligned and the licence condition allows for intermediate strategy updates if required.
Core-Q19. Do you agree with our proposed Digitalisation re-opener?
We believe the digitalisation re-opener reflects the expanding role of digitalisation throughout the energy sector and specifically within DNO responsibilities, where additional delivery and products may be required beyond what we have submitted as part of well justified business plan in this area.

It recognises that the Energy Digitalisation Taskforce Report was released shortly after the submission of the business plans, where there could be additional activity required to effectively deliver a digitalised energy future and the recognition that a change to smart meter infrastructure approach may be beneficial. We have noted that the re-opener window is planned for late January 2026 for DNOs and at any time for Ofgem. Ensuring organisations have appropriate time to deliver change effectively in the remainder of RIIO-ED2 post the re-opener decision is key. Also there is a proposal from Ofgem to have a materiality threshold of 1% above base revenue post the application of the Totex Incentive Mechanism (TIM) which equates to a 2% of base revenue for an uncertainty mechanism trigger point before the application of TIM. This is a variation from the materiality threshold level of 0.5% post TIM for the GD&T price control. We cannot understand why the RIIO-ED2 price control has not been set at 0.5% of base revenue post TIM.
Core-Q20. Do you agree with the proposed enhanced reporting framework associated with IT/OT Data and Digitalisation spend and DSAP investment proposals?
WPD agrees that explicitly understanding costs and spend on DSAP related activity is key, however it must be considered alongside measured benefits and value driven from that spend. We are supportive of an effective cost benefit analysis approach being taken to ensure cost effective delivery to benchmark across licensees. Our digitalisation programme covers our entire business and therefore it is expected that a TBM model for the entire organisation's IT and OT estate will be required. We would welcome some further detail on expected timescales to have a mature TBM that is expected to leverage the expected value. We feel it would benefit from more clarity around the expectation of the Action Plan reporting as part of the digitalisation licence condition and that expected from the proposed 'project layer' of TBM. We have demonstrated our commitment to be open in the progress and outcomes of our Action Plan through publication of an open and dynamic resource. A specific example is 'summary reports', which will, as a minimum be provided every six months as part of the digitalisation licence condition. The 'project layer' requested as part of the TBM would provide a single view output of a specific project its cost and some summary detail, however, providing an outcomes focussed view would potentially deliver more value when considered as a programme of activity. Clear guidance on the implementation would be required to ensure it is applied effectively and consistently between DNOs to meet the expectation of increased transparency in IT spend and comparability between DNOs.
Core-Q21. Do you agree with our proposal to adopt TBM as part of the RIGs/RRP?
Where Technology Business Management taxonomy can effectively remove the need for separate IT, OT and digital reporting from the RIGs/RRP process, rather than implement an additional layer of reporting then this is supported. An overview of the specific elements of the RIGs/RRP proposed to be superseded by TBM is required to fully understand the impacts. Clarity is required regarding the changeover period and the associated effort to potentially maintain two systems for a period to ensure consistency.

Core-Q22. Do you agree with our intention to modernise the regulatory reporting process?
WPD shares the view that regulatory reporting must be fit for purpose and proportionate. The "what" is reported is as important as the "how" it is reported. Ofgem recognises that there has been significant growth in the amount of information being requested from DNOs across various data templates and information requests. There are vast amounts of data that are provided to Ofgem, mainly provided in spreadsheets. The source of the data comes from various system and requires compilation into the spreadsheets. The deadlines are stipulated in RIGs and there are extensive rules and guidance to help with consistency in reporting. This data is important to Ofgem for monitoring performance in the price control as well as for future price controls. Ofgem should not just be looking at the data capture process in isolation. The use of the data, considered alongside the written reports for Ofgem and the associated DNO reporting to our own customers, must also be considered as part of a review of modernising the regulatory reporting process. While there are benefits to modernising the regulatory reporting process to enable data to be accessible between organisations and Ofgem, there is strong merit in reviewing/reducing the data requirements. Ofgem has not utilised much of the detailed disaggregated data that DNOs have provided in historical returns or within business plan data templates and therefore there is an opportunity to reduce the costs and regulatory burden for DNOs and Ofgem by consolidating the data requirements. The modernisation of the regulatory reporting process would require clear and agreed metadata and data dictionaries to aid the understanding and interpretation of data. The current proposal is, largely, a front-end IT focussed solution and would not reduce the effort required by DNOs to provide the regulatory reporting data, however, it would save Ofgem processing time through the adoption of a standardised data model. As well as considering the initial establishment of data transfer processes, it is very important to have an efficient and effective ongoing change process. Currently, it is very easy to change a spreadsheet to revise data reporting requirements. However, once an API is established more advanced notice will be required to change the reporting structures. Recent experience for the 2021/22 reporting year shows that the review process can be delayed and that reporting requirements can be communicated late. Such delays will not allow API interfaces to be changed in time to provide the required data. Ofgem's process for new data collection should give sufficient advance notice to be able to change systems. Paragraph 4.39 suggests that this process will provide benefits for re-opener processes. This is optimistic, because most re-openers have bespoke data requirements which only operate once or twice during a price control. The development of interfaces for limited interactions could incur unnecessary costs, especially where additional data (above that which is routinely provided) is required. An example of such a change is Ofgem's recent decision on RIIO-ED1 Green Recovery expenditure in RIIO-ED1, which now requires additional reporting not envisaged at the time of the price control. Comparing the RIGs now to those in place in DPCR5 or the start of RIIO-ED1 demonstrates how the reporting needs to be agile to ensure

Ofgem can monitor performance under the price control. The costs and benefits associated with making such changes in an API must be fully considered, along with the time and resources required to implement the changes. The high number of uncertainty mechanisms proposed for RIIO-ED2 means that re-opener processes need to be agile and not lead to delays. We suggest that re-openers should be outside the scope of the initial programme. In terms of potential solutions, our existing data portal, Connected Data Portal, is a suitable mechanism to provide this data as it has a recognised standard API approach, mechanisms to enable the four levels of data access and could facilitate the wider sharing of regulatory reporting as required. We share a significant amount of data to customers and stakeholders through this format and whilst there are economies of scale through utilising an existing platform, the main costs associated with sharing data are in surfacing, compiling, cleansing and engineering the data. Not all regulatory reporting data is readily available in systems and therefore there will be substantial system and process change requirements for DNOs to automate the whole process. Initial activities should therefore focus on the process of data sharing.
Core-Q23. Do you agree with the proposed timeline for implementation of this modernisation?
No. WPD does not support the proposed timeline. The proposal to start an innovation project between DD and FD is at a time when both Ofgem and DNOs are carrying out detailed and complex work on establishing the allowances and mechanisms for RIIO-ED2. Many of the staff that would provide user input into the projects are engaged with the price control process. We suggest that the innovation project should be delayed to take place in the first year of RIIO-ED2. The proposed 'go-live' is reasonable, provided that the scope of the development is limited to the development of data transfer process. Assuming the innovation works are in year 1 of RIIO-ED2, the system developments can then take place over the following two years so that transfer systems are in place by 'the end of year three of the price control' and therefore expected to be utilised for year four reporting. As referred to in Q22, the detail of the modernisation proposal appears to focus on the front-end data sharing and standardisation approach and does not impact the approach, effort and cost in collating the data; the timescales would need to be extended and costs increased to effectively deliver this change across the licensees. This requirement has been proposed after submission of the business plans and therefore DNOs have not incorporated the associated costs in business plan forecasts and therefore appropriate and effective funding mechanisms have not been considered. As part of the innovation project, there should be detailed understanding of the likely costs for implementation and these costs should be allowed as extra allowances under an RRP IT re-opener.
Core-Q24. Do you agree with our proposed design of the DSO incentive?
No.

The DSO activity will play a critical role in RIIO-ED2 to enable stakeholders to achieve net zero in a cost effective manner and embrace the principles of "touch the network once" and the use of flexibility. Therefore given the benefits leveraged off the back of successful DSO operations, there should be a greater incentive to accelerate deployment and outperformance to ensure that customers fully benefit from DSO activities. Therefore we believe the DSO incentive should be attributed a more significant weighting than the +/- 0.2% of RORE per year proposed. The proposed DSO incentive design covers a sensible choice of metrics, panel assessment and survey, however there is further work needed to calibrate the weightings of the metrics. We agree on the single performance panel across all DNOs to achieve consistency and this striving for consistency is mirrored in the other two assessment elements.
Core-Q25. What are you views on the outturn performance metrics and RRE we are proposing to include in the DSO incentive? If you do not support their inclusion, please outline which alternative outturn performance metric(s) or RRE you think should be included in the framework instead.
We believe it is too early to form a firm view on the outperformance metrics and RRE. We welcome the further engagement proposed by Ofgem via the working groups as stated in the Draft Determination to finalise this incentive.
Core-Q26. Do you agree with our proposal for the DSO re-opener?
We agree in principle to there being a DSO re-opener but further information is required regarding the scope and triggers for this mechanism. Also there is a proposal from Ofgem to have a materiality threshold of 1% above base revenue post the application of the Totex Incentive Mechanism (TIM) which equates to a 2% of base revenue for an uncertainty mechanism trigger point before the application of TIM. This is a variation from the materiality threshold level of 0.5% post TIM for the GD&T price control. We cannot understand why the RIIO-ED2 price control has not been set at 0.5% of base revenue post TIM. We also feel that this re-opener should be able to be triggered by either the DNO or Ofgem. Currently the re-opener can only be triggered by Ofgem but we feel that the DNO should be able to trigger it in order to react to our stakeholder's requirements in a timely and effective manner.
Core-Q27. Do you agree with our proposal to introduce a new whole system strategic planning Licence Obligation?
No. We are disappointed to see this introduced in the Draft Determination without being identified as a requirement in the SSMD or in the Business Plan guidance. Current whole system licence obligations relate to publishing a register which formatting has been agreed by DNOs under Open Networks. Whilst there are significant proposals laid out by networks in their business plans, there is a risk that further proposals potentially covered by this licence obligation are not covered by allowances.

We are concerned that there is insufficient time to coherently develop the guidance to form the LO in the time ahead of Final Determination and consideration should be given to phase in formal drafting in the future.
Core-Q28. What are your views on the digital tools that could be used to support this?
It is difficult to articulate exactly what is required to support a new whole system strategic planning Licence Obligation as this has not been developed at this stage. However we have identified below digital tools which we believe may be able to support this Obligation should it proceed. To effectively enable a digital approach to whole system planning a number of key digital tools and solutions will be required. There are a significant number of actors and contributors required to deliver effectively, this means tailoring digital solutions and data engagement appropriately to enable consistent and considered input. Our current approach, captured in our Digitalisation Strategy, is focussed on three key mechanisms: • Data download for direct access • Highly visual in the form of interactive maps and dashboards • APIs to automate functions, processes and insights These mechanisms are made available through the use of standardised datasets, such as EPRI Shapefile to share geospatial information and an agreed metadata and data dictionary approach to facilitate data interpretation and insight. NESM, delivered through ENA’s DDSG is a good example of standardised data approaches enabling a common view of information in a central repository. WPD already ensures its data is shared utilising recognised standards, with examples being our linear and non-linear asset base and constraint managed zone data being available in standard formats that can be integrated in to any existing GIS solution, providing effective data overlays. Common Information Model (CIM) is another key digital tool, which WPD currently uses to share its existing asset and connectivity data regularly and continuing to expand this to present a future network model will be important in the support of genuine whole system planning. To deliver open collaboration beyond datasets, digital tools such as Atlassian’s Confluence, a web-based corporate wiki, enable a broad range of stakeholders to contribute to single views in an open and collaborate environment, removing barriers for engagement and ensuring all voices are heard. For more technical data sharing, focussing on understanding assumptions and how data has been processed, software development and control tools, such as GitHub, provide an openly available mechanism to share this transparently, enabling other individuals and organisation to contribute, adapt and ensure a community of collaboration. WPD already has a mature GitHub environment, which has been used to demonstrate how multiple datasets can be used to deliver insight and value and host data science challenges, where a large community of collaborators work to provide insight to some of energy’s most important challenges.

5. Meet the needs of consumers and network users

Core-Q29. Do you agree with our proposed target and thresholds for the deadband, maximum reward and penalty?
We agree with the proposed target of 8.9 and the proposed thresholds of 8.7 and 9.1 forming the deadband. The levels of customer satisfaction delivered in RIIO-ED1 have been achieved with a great deal of focus and investment by the DNOs and hence this will need to be continued and potentially increased to maintain the same level of service going forward. For increased levels of performance, further enhancements will be required, especially when you then layer in the significant increase of customer transactions that will be experienced during the period (e.g. 1600 connection enquiries per day). With these increases in levels of transactions investment has to be made to ensure that the high standard of customer service is maintained as a minimum and further investment will be required to raise the bar even further. With this in mind, Ofgem should consider maximum reward to be 9.3 and penalty score to be 8.5 which maintains the symmetry of the incentive. This will achieve a high standard of customer satisfaction while incentivising companies to maintain and improve upon high levels of performance in pursuit of the maximum reward at a slightly lower level than 9.4. However also sustaining maximum penalty at 8.5 which is a higher bar than Ofgem proposed. In summary the WPD view is: Maximum Reward : 9.3 Reward Trigger Point: 9.1 Target : 8.9 Penalty Trigger Point: 8.7 Maximum Penalty : 8.5
Core-Q30. Do you agree with our proposed approach to working with DNOs to implement Strom Arwen actions related to customer satisfaction?
Yes. We fully support the proposed approach to working with Ofgem and the other DNOs to implement the Storm Arwen actions. We especially look forward to working with Ofgem and the DNOs to achieve greater consistency in relation to future reporting metrics. Please also see our response to consultation question Core-Q3.
Core-Q31. Do you agree with our proposed target and maximum penalty score?
Yes we agree with a target of 2.8 and a maximum penalty award of 8.0 for the Complaints Metrics.

Core-Q32. Do you agree with our proposal to remove the activities proposed from DNOs' baseline allowances?
In relation to the three exclusion areas, we agree with them being removed as a direct deliverable by the DNO. However, it is important these actions are maintained as interventions that DNO-funded outreach partnerships are able to facilitate access to on behalf of customers (e.g. funding the advice and access to third party funding streams for boiler replacements, but not the DNO funding the repair/replacement activity directly). It is very important that DNO partnership schemes are as holistic as possible and the crucial role we can play in stimulating action in this area should be maintained. In our view the wording in Ofgem's decision should therefore be clarified. In respect to the training of staff, it is also important that training to identify and signpost support through referral partnerships for low carbon transition support is included. For clarity WPD did not propose any expenditure for these types of activities and there is therefore no requirement to remove any costs from our proposals.
Core-Q33. Do you agree with our proposals for the Consumer Vulnerability ODI-F?
We broadly agree with the scope of the ODI-F and the areas of performance that will be measured. However, while we believe it will incentivise DNOs to ensure stated targets are met, we are concerned that the incentive framework does not adequately incentivise innovative thinking beyond these target areas. The framework fails to address significant disparity in performance levels between the DNOs, and in fact the targets set will perpetuate a postcode lottery in support provision throughout RIIO-ED2. While the SECV incentive in RIIO-ED1 has successfully recognised this disparity in the assessments and rewards administered, the targets now being set for RIIO-ED2 demonstrate significant differences in the value of the outcomes delivered for customers, but do not do enough to significantly close this gap between the top and lowest performing companies. For example, WPD will have to deliver the entirety of either UKPN or SSEN's NPV target for fuel poverty on top of our own target in order to qualify for a reward. In reverse, UKPN and SSE are considered to be delivering stretch performance by delivering one fifth of WPD's programme. We recognise that there may currently be some inconsistencies in the application of the common DNO social value framework, which could account for some of the discrepancy in the targets. It is therefore vital that these are addressed urgently through the Consumer Vulnerability Working Group, to ensure that the consistency the framework enables is realised. WPD is already working with Ofgem and the other DNOs to deliver this consistency and necessary assurance. However this may not fully account for the wide range of target levels proposed for the different companies which we have discussed above and in more detail in Q34, and which do not appear to be fair and proportionately stretching for all companies.

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

We have concerns in three areas:

1) Not achieving a fair and proportionate level of minimum services performance across companies in relation to the value of services delivered.

Ofgem's stated desire to achieve fair and proportionate level of minimum services performance across companies in relation to PSR reach and customer satisfaction, is in direct contrast to the target setting approach applied to NPV for fuel poverty and LCT services. In these areas Ofgem's proposed targets will lead to a postcode lottery in the quality of support provided by companies, as summarised in the table below:

Table 12: Consultation position - Consumer Vulnerability Incentive (ODI-F): the value of fuel poverty services delivered (NPV, £m)

DNO	Year 2 target	Year 5 target
WPD	£21.3m	£50.97m
UKPN	£3.71m	£9.28m
ENWL	£19.9m	£60.8m
SPEN	£3.19m	£9.66m
SSEN	£2.6m	£15.7m
NPG	£6.76m	£16.36

As referenced in our response to question 33, the targets that have been set do not place sufficient stretch on poor performing companies and will therefore not close the gap to the top performers. Companies that have earned substantial rewards in RIIO-ED1 as part of the SECV incentive do not appear to see this performance translating into an enduring stretch target, and in some cases must only deliver a fifth of WPD's target as their baseline.

The differences in the volume and size of support services offered by DNOs cannot be explained away by supposed significant variances in the needs of specific regions, the prevalence of vulnerability and stakeholder/customer needs. WPD covers 25% of the UK encompassing a full spectrum of urban/rural and social economic demographics and therefore does not understand how these factors can be cited to account for such huge differences in the value of services that can be delivered.

Subject to the work to ensure consistency in application of the Common Social Value Framework, the highly disparate targets proposed by Ofgem currently fail to recognise the significant differences in the scope, depth and quality of the services being delivered by DNOs and offer little incentive for poor performers to improve the provision of their support and therefore reach a fair and proportionate level of minimum performance by the end of RIIO-ED2. It cannot be right that companies of a comparable size to WPD (and proposing similar, or in some cases greater, levels of spend in relation to customer vulnerability) can earn significant rewards as part of this ODI-F for delivering a fraction of our targets. Ofgem has not set common baseline targets, and therefore the baselines per company are wildly different which renders it impossible to judge "average" performance in the sector. Although the draft determination states that companies should not be rewarded for average performance, the targets proposed by Ofgem actually ensure that companies are rewarded for delivery that falls below the industry average based on the numbers displayed in the table above. This does not seem reasonable. Companies that have only delivered modest performance in RIIO-ED1 can now earn significant rewards by improving their performance to a level that still falls significantly short of other DNOs in the sector. Rather than close the gap, this is likely to widen the range in quality of service provision across different areas during RIIO-ED2.

2) <u>The weightings applied to the incentive components</u>
While we recognise the maturity of the approach to measuring PSR reach and its overall importance (meaning it should carry strong weighting) it needs to be recognised that this does not reveal the quality of the DNO's support for vulnerable customers. We therefore feel this is disproportionately weighted at 40%. It is possible to increase PSR reach but compromise the overall quality (e.g. adding new customers, but not sufficiently cleansing poor quality, out-of-date data) which is not in the best interests of customers. The crucial measure is what services and outcomes high quality PSR can lead to, such that are measured by the other components of this incentive. Of these components we feel that in particular the NPV targets associated with fuel poverty and LCT services should have a stronger weighting – reflecting the crucial role actions in these areas will have in directly supporting vulnerable customers. While these are newer areas of delivery (compared with the PSR reach methodology) the consistent application of the common social value methodology with independent assurance and audit (e.g. from SIA partners) should give Ofgem and wider stakeholders confidence in the validity and consistency of the values reported.

In the draft determination Ofgem states that it is protecting consumers and DNOs from excessive under or over delivery by limiting the weighting of the NPV targets. However, it also states that the deadband (cap and collar) around the stated targets serve to provide this protection. If this is the case then the limited weighting is excessive and not required if adequate protection (via the deadband) is already in place to mitigate the risk.

Finally, Ofgem has stated that the reason for having a weighting for the customer satisfaction surveys that is the same as the target for the NPV targets is because this will account for the "risk" that DNOs could attempt to deliver support services to those who do not want the support or be light touch in the support they deliver. However the measure of NPV is fundamentally a measure of the quality of this support, as the social value model will only record values for service delivered for individual customers, not services attempted. It is not possible to deliver huge savings for customers that do not want or require this support, such is the level of customer interaction and buy-in required to achieve this value. Again, we therefore do not recognise the risk cited by Ofgem as a reason to not have a greater weighting attributed to the NPV components of this incentive, compared to the customer satisfaction components in this case.

3) <u>Customer satisfaction targets for LCTs and fuel poverty</u>
For the longstanding Broad Measure of Customer Satisfaction (BMCS) where multiple years of revealed performance is available, a target of 8.9 has been set. However, for brand new surveys, in particular relating to LCTs, there is a lack of robust historical performance data yet Ofgem has set an immediate performance target higher than the BMCS. Whilst we will strive to deliver exceptional performance at all times and from the outset of RIIO-ED2 we would propose that it would be more reasonable for the targets to mirror the BMCS. In addition as this is such a new delivery area it would be more reasonable to apply the first assessment to year 2 performance only, rather than an average of both years 1 and 2. This will allow time for a bedding in period of brand new services which will require input from customers to refine,

therefore ensuring we are consistently meeting their expectations and embedding enduring positive impacts.
Core-Q35. Do you agree with our proposal for the Annual Vulnerability Report ODI-R?
Yes.
Core-Q36. Do you agree with the proposed content of the annual report? If not, please explain why and give details of your preferred alternative.
Yes.
Core-Q37. Do you agree with setting the maximum reward and penalty limit at +/-50% of the target?
No. We agree that it is sensible to set this maximum at a level which is above the level of current DNO achievement without it stretching to an unachievable value. Thus in light of this we propose a maximum reward threshold of +/-40% deadband which is a better option to drive improvement whilst maintaining an achievable level for DNOs. For both TTQ and TTC, due to the greater number of enquiries we expect due to LCT take-up, a 50% max reward threshold will be too high to achieve. Those DNOs who are not performing will then have to operate at a high level in order to avoid penalty and this will improve the service that customers receive.
Core-Q38. Do you agree with setting a deadband of +/-20% of the target?
No. We agree that it is sensible to have a deadband around the target but this should be narrow enough to allow DNOs to perform at a higher level whilst achieving an incentive. Overall this will drive good behaviour to make the connections at the time to suit the customer and hence provide better customer service. In light of this a +/-10% deadband is a better option to drive improvement whilst maintaining an achievable level for DNOs. Those DNOs who are not performing will then have to operate at a high level in order to avoid penalty and this will improve the service that our customers receive.
Core-Q39. Do you agree with our proposed design of the Major Connections incentive?
No. We believe that the incentive should be symmetrical i.e. include a reward mechanism as well as a penalty mechanism, and include all Major Connections RMSs. This would drive good customer service across all Major Connections RMSs and customers. The sample size for the MCCSS also needs to be statistically robust. In many DNOs some RMS could provide a very small sample size, especially if that DNO had demonstrated competition in the relevant RMS.

“Major connections” needs to be fully clarified in terms of “what work categories are defined as “Major Connections””. Through SQ25 we understand that it will apply to all RMSs which does conflict with the description as major connections. It is also unclear how DNOs will be compared against each other when some RMS are measured at full performance where competition has not been demonstrated against RMS with a lower scope where competition has been demonstrated. We welcome the ongoing dialogue with Ofgem with regards to the design of the Major Connections incentive.
Core-Q40. Do you agree with our proposed approach to target setting and applying the penalty?
No, please refer to our response to Core-Q39 also. We believe that the incentive should be symmetrical i.e. include a reward mechanism as well as a penalty mechanism, and include all Major Connections RMSs. We welcome the ongoing dialogue with Ofgem with regards to the design of the Major Connections incentive.
Core-Q41. Do you agree with our proposal to require reputational reporting of timeliness metrics for all RMS?
Yes, a reputational report for all RMS brings visibility and clarity to the performance on DNOs. It can be also used as a baseline for future incentive mechanisms as required.
Core-Q42. Do you agree with our proposal to launch a wider review of the Connections GSoP (that is, beyond updating the payment amounts for inflation and incorporating standards for DG customers)?
Yes, we would support a wider review of Connections GSoPs. We agree that an update to payment amounts is good with a separate review conducted outside of the RIIO-ED2 decision timescales and by April 2024. This allows time for changes as a result of the Access SCR to become business as usual and will set the review against a rising number of LCT applications
Core-Q43. Do you have any views on what else could be done to help speed up connections to the distribution network and or develop a standard for the overall (ie, end to end) time to connect?
We believe that we will speed up connections to the network through: - • The digitalisation of connections i.e. online domestic LCT acceptances; • Providing the relevant data and tools so that customers and stakeholders can “self-serve” both budget and firm quotations; • The development of an online customer portal so that customers can apply, accept, pay and schedule their connection online; • Through enhanced network monitoring and management of connection milestones and interactivity; • Through the offer of alternative solutions/flexible connections

Time to connect mechanisms are a simple metric that work well for small connections (LVSSAs and LVSSBs) as the majority, if not all of the items impacting on timescale are within the DNOs control.

Time to connect mechanisms do not work well for major connections. This is because they include timescales that are outside of the DNOs control. Also, customers may wish to delay a connection to meet their broader requirements and so could fall outside of a time to connect incentive even though they are happy with the DNOs performance.

A customer satisfaction survey is the ultimate mechanism for measuring customer satisfaction for major connections although, as per our responses to Core-Q39, we believe that such a mechanism should include a reward as well as a penalty in order to drive continual service improvements.

6. Maintain a safe, resilient and reliable network

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

WPD's Business Plan documentation provides details of extensive stakeholder engagement. Part of these engagements has been focussed on improvements to network performance.

Category 3.1 of Section 6 of WPD's RIIO-ED2 Business Plan Annex 5 – Giving customers a stronger voice – Enhanced Engagement specifically relates to Network Resilience which includes:

- Core commitment 19 (Deliver improved network reliability where on average power cuts are better than one interruption every two years lasting 24 minutes.)
- Core commitment 20 (Improve service for at least 8,260 worst served customers by undertaking 70 schemes.)
- Core commitment 21 (Improve the overall health of the network by 22% with an Investment of £210 million per annum).

The summary in Annex 5 describes the various stages of stakeholder engagement, with the final stage concluding that

"*They (stakeholders) felt that the value of the investment – fewer power cuts and a more reliable network – outweighed the concerns over cost, <u>with the majority (77%) agreeing or strongly agreeing that the level of expenditure was acceptable to them</u>. By contrast, there was little appetite for increased risk, with stakeholders seeing this and an important factor in maintaining service to customers and in assessing modification to the network.*"

This expenditure relates to delivering a 0.5% reduction in customer interruptions and 2% reduction in customer minutes lost.

This shows that WPD had high stakeholder support for continuing to make improvements to network performance.

Core-Q45. Do you have evidence of the cost of reliability improvements and the impact that lowering the revenue cap will have on them being achieved?
As part of the business plan submission, WPD has proposed investment of £26m in quality of supply improvements to respond to our stakeholders' desire to have a further improvement in supply reliability in RIIO-ED2. Ofgem has proposed not to give quality of service allowances with means that the funding of these improvements needs to be covered by incentive returns. It is therefore important that companies have the opportunity to generate rewards from the IIS, in order to cover the costs of making improvements to network performance. However, WPD is concerned that Ofgem's proposals to set targets on own performance, a requirement for further ongoing improvement and no allowances, will not provide sufficient returns to cover the costs of network performance investment. The proposed change in approach for setting CML targets from that suggested in the Sector Specific Methodology Decision leads to tightening of targets for those companies that have industry leading performance (and relaxation of targets for those that have poorer performance). The leading companies have already made significant improvements to operational practice and systems and therefore have a diminishing opportunity to make further improvements. Tightening targets for frontier companies makes it significantly harder to achieve rewards. This seems illogical and unfair, especially as the scope for further improvements is limited for companies with leading performance. Since there are no allowances to make improvements, companies need to invest just to stay neutral on the IIS. This means that companies are investing to avoid a penalty, rather than investing to generate a positive return. The current proposals for tougher targets and no allowances means that IIS biased towards penalties. Furthermore, not all details for IIS are currently available, because Ofgem is yet to set the incentive rate. It is the incentive rate in combination with revenue caps that sets the scope of what improvements can be delivered. The impact of lowering the revenue cap for IIS reward, could limit company ambitions where companies have scope to make improvements.
Core-Q46. What are your views on moving to an asymmetric cap and collar?
The move to an asymmetric cap and collar leads to a skewed incentive that is compounded by a target setting methodology that is biased towards penalty. The IIS incentive should be balanced, with equal opportunity for penalty and reward. Currently the proposed RIIO-ED2 mechanism is biased towards penalty with limited opportunity for reward. In paragraph 6.12 Ofgem recognises that the DNOs ability to make improvements has begun to taper off with annual improvements being lower than in previous years. This means that the ongoing scope for making improvements is diminishing. This means that the likelihood of DNOs achieving maximum rewards is significantly reduced in RIIO-ED2. Therefore limiting the upside reward to 100 RORE bps is an

unnecessary constraint in the incentive mechanism because many DNOs are unlikely to achieve it.
Core-Q47. Are there alternatives to reducing the revenue cap that you think would better balance increases in reliability and the cost to consumers than reducing the revenue cap?
There are two alternatives to make the incentive more balanced: **<u>Option 1 (WPD preference) – Retain the 250 RORE bps for both reward and penalty</u>** Ofgem recognises (in para 6.9) that the IIS has been a very effective tool for incentivising network performance improvements. This is because it has had very strong positive incentive properties, to which the licensees have responded, investing in network devices, automation and improving operational practice. While the current proposal for RIIO-ED2 limits the opportunity for rewards because of tougher targets and no allowances to make improvements, there should not be a cap on the ambition of DNOs to seek further improvements. It should be recognised that such improvements would ultimately benefit customers through a more reliable network. WPD's proposed solution for symmetrical IIS incentive is that the scale of the IIS incentive should be 250 RORE bps for both penalty and reward. **<u>Option 2 (an alternative) – Limit both reward and penalty to 100 RORE bps</u>** Ofgem has considered limiting both reward and penalty to 100 RORE bps. In paragraph 6.33 Ofgem provides the reasons why it has rejected reducing the collar to 100 RORE bps. We strongly disagree with the third bullet. This suggests that since there has been historical outperformance under the IIS that the risk of reaching the underperformance cap is low. In RIIO-ED2, Ofgem is seeking to tighten the targets, apply performance improvement factors, provide no allowances for making improvements, as well as removing some of the situations where a one-off exceptional event can be claimed. This means that there will be a significant risk of under-performance, which could easily lead to the penalty cap being reached (especially in years where there is poor weather that impacts network performance). The proposals for RIIO-ED2 cannot be assumed to be the same as the historical IIS arrangements and therefore performance in previous price controls is irrelevant to the reward/penalty opportunity in RIIO-ED2. Under current RIIO-ED2 proposals there is greater risk of downside, especially for frontier companies. We also strongly disagree with the fourth bullet This suggests that the changes being made for CML target methodology mitigate the risk of DNOs falling into penalty.

This is only true for those companies that have not responded to the incentive in a similar way to WPD (which is demonstrated to be a frontier performer in CML). The proposed mechanism for setting CML targets provides easier targets for companies that have not made historical improvements and penalises those that are leading the industry (including all four WPD licence areas). Figure 15 clearly shows that WPD licence areas and LPN will be set tougher targets using average performance. While the change to basing targets on average performance helps those that are poorer performing, it penalises those setting the benchmarks. This means that it is more likely that the WPD licence areas and LPN will be in penalty. In conclusion, since there is an increased risk of penalty, especially for frontier companies, the application of a downside collar of 100 RORE bps can be applied. Our alternative solution for maintaining a symmetrical IIS cap and collar is have both the penalty and reward limited to 100 RORE bps.
Core-Q48. Do you agree with how we have characterised the operation of the current CML methodology and our reasons for changing to setting targets in line with our CI methodology?
No, we disagree. **Target Setting Approach** We believe that the argument to change the approach for setting CML targets is flawed. It relaxes the potential targets for poorer performing companies and imposes tougher targets on companies that have been leading the industry and setting the benchmarks. In para 6.52 Ofgem states: "Over RIIO-ED1, some DNOs have significantly improved their CML performance, driving down the lower quartile benchmark. As a result, the other DNOs who have not improved their performance as much will see a much more significant step change in their RIIO-ED2 targets than was the case RIIO-ED1" Ofgem goes on to argue that companies are not funded to drive towards upper quartile performance and therefore targets should be based upon their own performance. However, by setting targets based upon own performance, poorer performing companies can continue to be laggards and have a better chance of outperforming the IIS. Para 6.56 explores the considerations that are influencing the choice of target setting mechanism, with a view of not putting companies into a penalty position. The first bullet considers whether DNOs should be able to improve at the same rate, implying that this is not the case (by selecting DNO own average for CML targets).

WPD has achieved significant improvements in CML performance through focused operational practice that places the restoration of customer supplies as a very high operational priority. Other DNOs with less improvement may not have the same approach and hence are not improving to the same extent. The historical evidence of significant improvements in WMID and EMID performance following the acquisition of the licence areas by WPD, shows that adopting a more focussed approach can lead to significant improvements. WPD should not be disadvantaged by being an industry-leading performer.

The second bullet questions the value of putting DNOs into a penalty position, if their rate of improvement is already tapering off. Since WPD has already implemented improvements such as network automation and enhanced operational practices, it has less scope for further improvements than other DNOs.

Para 6.57 shows the impact of moving from setting targets based upon benchmarks to setting them based upon own average.

This clearly shows that targets are being relaxed for companies that are poorer performing and tightened for this that set the benchmarks.

Given that WPD has already implemented significant performance improvements and has limited scope for further improvements it is illogical to impose more stretching targets by using own DNO average.

We therefore suggest that targets for companies beating the benchmarks should be based upon the benchmarks not own performance.

Proposed solution:

- Option 1 - set targets based upon benchmarking.

- Option 2 - should Ofgem wish to retain the relaxation of targets for poorer performing companies, then their targets could be based upon a four year average, with the targets for companies that are influencing the benchmarks having targets set based on the benchmarks.

Improvement Factors

Assuming that the starting point for RIIO-ED2 target is set on a reasonable basis, the application of an improvement factor to drive better network performance is a reasonable measure, provided that the efficient costs of improvements can be recovered.

However, applying an improvement factor to tough targets is not reasonable for frontier companies.

Given that WPD has already implemented many performance initiatives, there is limited scope for further improvements and an improvement factor applied to current performance means that there is a greater risk of penalty.

Since companies beating the benchmarks have already made improvements, an alternative to the 0.5% improvement factor is to have the level set to zero.

Proposed solution:

- If the process for setting the starting target does not change, set the performance improvement factor for companies ahead of benchmark to zero.

Timing of setting targets

Ofgem proposes to publish final targets around February 2023. This is too late.

We accept that setting targets based upon the latest available data is reasonable to establish targets that are representative of delivered industry performance.

However, the data required for deriving that target has already been submitted to Ofgem at the end of April 2022 and therefore there is sufficient time for Ofgem to incorporate the data into revised targets so that they are ready for Final Determination in November 2022.

Publishing the targets in Final Determinations means that DNOs have the full visibility of the price control package in November 2022.

Core-Q49. Do you agree with our rationale for retaining our RIIO-ED1 position on QoS funding? Can you provide any evidence that an alternative approach would not result in double rewarding alongside the IIS?

QoS Allowances

Ofgem proposes to disallow QoS funding. This compounds the risk of penalties.

Para 6.67 suggests that the provision of QoS funding creates the risk of double rewards. We disagree.

Ofgem's current proposal to base targets upon own average performance embeds existing practice into the targets. This means that historical investments and operational practice need to be maintained just to keep performance at the same levels.

Applying performance improvement factors means that the investments and/or operational practice need to be enhanced in order to remain in line with improving targets. If such improvements are not made then the DNO is subject to penalty. This means that companies need to invest in order to avoid penalties.

Ofgem's proposal not to fund QoS means that means that there is no allowance for the investment just to stay neutral (i.e. have no penalty or reward) in the IIS incentive.

If companies do not invest, they will be subject to penalties. Companies that invest to stay neutral on the IIS, will have no penalty, but they will not be funded for the investment. The absence of allowances means that companies are disadvantaged, rather than gaining double rewards.

Para 6.67 also suggests that DNOs have requested QoS funding to enable them to maximise rewards. This is an incorrect conclusion for WPD.

WPD's proposals for QoS investment are based upon expanding existing automation programmes. This would enable WPD to make marginal improvements to performance as described in our Business Plan core commitment 19. Effectively this investment would help to keep performance neutral against IIS.

Such improvements are supported by stakeholders and therefore we believe that funding should be made available to allow companies to be neutral against IIS targets. Should companies wish to go further, any outperformance would then be at the discretion of the licensee, determined by a cost benefit of the incentive reward versus the costs of the investment. Proposed solution: • Companies should be provided QoS funding to remain neutral on the IIS incentive.
Core-Q50. Do you have any examples of situations where fault-related interruptions could be genuinely "exceptional" and how these could be separately identified from those that occur during planned works?
We welcome the approach to providing clearer guidance on what constitutes a one-off exceptional event. We also welcome that faults caused by foreign objects will be classified within the OEE definition. These are outside of the control of DNOs and should remain valid reasons for exclusion.
Core-Q51. Do you agree with our assessment of the OEE thresholds and the financial impact on each DNO?
No, we disagree. Exposing each company to the same absolute financial value disadvantages companies with fewer customers. Companies with fewer customers will have lower revenues and therefore applying a fixed absolute value has a bigger proportional impact on smaller companies. The scale of the threshold should be a proportion of the customer base.
Core-Q51a. GSOP proposals
We disagree with the statements in paragraphs 6.112 and 6.113, where Ofgem states that it is not essential to review GSOPs at the same time as the price control. Paragraph 6.78 states that Ofgem's view is that the definitions for Category 1 severe weather should remain the same under IIS and GSOP. There is therefore an inherent link between GSOPs and IIS SWEE thresholds. There needs to be clarity on all IIS parameters at Final Determination and therefore GSOPs should be revised on the same timescales as RIIO-ED2 determinations.

Core-Q52. Do you agree with our proposal not to have an end-of-period adjustment mechanism? If not, what criteria should we use to determine whether a DNO has used its allowance for WSC, without it creating uncertainty?
We agree that there should not be an end of period adjustment mechanism removing allowances for projects where performance improvements are not as expected for investments that have been carried out. DNOs will make investments for worst served customers in good faith that network performance will improve, but the random nature of faults means that this may not be achieved. Ofgem should however be clearer in describing the end of period adjustment, because a UIOLI mechanism includes a form of end of period adjustment. In this case allowances are reduced where investments are not made.
Core-Q53. Are there any other areas or metrics that we should include in our governance framework?
The amount of expenditure proposed for WSC is relative small. While we recognise that this is an area of higher stakeholder interest, the governance arrangements introduce a risk of excessive regulatory burden. We accept that the providing details on the following are reasonable governance requirements: • Schemes identified • The number of WSC at the time of identifying the scheme • Progress on schemes underway • Final costs of projects However, we do not see that it is necessary to estimate the expected CI benefit, especially as actual performance is likely to be different due to the random nature of faults on the network. The improvement may be difficult to estimate (e.g. how many fewer bird strikes will happen if bird flight diverters are installed). The governance arrangements should be such that they can be captured through annual RIGs reporting, in simple templates. Detailed narratives should be avoided. The governance requirements should be proportionate and not introduce excessive regulatory burden or micro-reporting at a detailed project level.
Core-Q54. Do you agree with our proposed approach on NARM?
We have a fundamental issue with NARM output targets not being revised in line with volume reductions determined in disaggregated benchmarking. By reducing allowances for asset replacement and not reflecting these reductions in lower NARM output targets, Ofgem is imposing a hidden additional efficiency expectation into the price control. The derivation of NARM risk improvements is directly linked to the volumes of activity carried out. Reducing volumes of activity means that the consequential output delivery is lower.

It is wholly inappropriate not to reduce NARM risk targets where volume reductions have been applied.

From paragraph 6.143 of the Core Methodology document it appears that the proposal to not adjust NARM output targets is based on Ofgem's assessment of the mix of asset interventions that DNOs have undertaken in RIIO-ED1 to deliver against their NOMs targets. In particular, this appears to relate to analysis of the proportions of Refurbishment (SDI) interventions compared with Asset Replacement interventions relative to the RIIO-ED1 forecasts.

Ofgem suggests that because there has been an over-delivery in RIIO-ED1 that this is replicable in RIIO-ED2. This is not the case.

The industry has responded to the challenge posed by Ofgem to incorporate long term risk into the RIIO-ED2 NARM metric, which has resulted in greater differentiation of the benefits of replacement compared with refurbishment than was visible in the measurement used in RIIO-ED1 NOMs (which is based on the improvement in risk held in a single year only).

This differentiation has also been improved by the changes to the Health Index bandings for HI1 and HI2 that have been introduced in the NARM methodology to enable better differentiation of the long term risk associated with new assets compared with older (but good condition) assets.

Furthermore there have been changes to the types of refurbishment activity that contribute to NARM with removal of activities such as repair of fluid filled cable joints, which under the RIIO-ED1 NOMs have a similar impact to replacement of the entire cable section. This removes any disproportionate benefit associated with these activities from RIIO-ED2 NARMs.

These improvements mean that the NARM metric in RIIO-ED2 better reflects the scale of benefit provided by each type of intervention, which means that the use of refurbishment will have a lower net impact on output measures in RIIO-ED2. The opportunities that existed in RIIO-ED1 are no longer available.

NARM targets must be reduced to reflect reductions in allowances.

There are two approaches that could be adopted:

Option 1 – Adjust outputs in line with disaggregated volume assessment.

Ofgem's Engineering Hub has assessed DNO Engineering Justification Papers and proposed volumes dependent upon whether EJPs are fully or partially justified. These volumes flow through to the allowances that are determined under disaggregated cost benchmarking.

The data provided by DNOs for the NARM output targets is presented by asset category. Revised targets could be determined by prorating the risk points for each asset category in line with the volume reduction. The combination of all the prorated values would lead to a revised target.

Based upon the volume reductions currently proposed in the draft determinations for NARM related activities, calculating pro-rated adjustments per asset category would lead to the NARM targets having to be reduced to the following percentages of the current NARM targets.

NARM target reduction percentages required to align NARM targets with volume reductions			
WMID	EMID	SWALES	SWEST
60%	59%	69%	75%

Option 2 – Adjust outputs inline with allowance reductions

In paragraph 6.142 Ofgem states that both disaggregated and totex benchmarking is combined to provide the allowances for asset replacement. While these allowances are not directly associated with volumes, any reductions to allowances represent a reduction in the level of activity that can be carried out and consequently a reduction in NARM risk reduction output that can be delivered.

Revised targets can be derived by prorating the NARM risk outputs in line with the proportion of allowance reduction (e.g. a 20% reduction in allowances leads to a 20% reduction in NARM risk output target).

Core-Q55. Do you agree with our proposal to pass through SW 1-in-20 costs as a variant totex allowance rather than a fixed allowance in RIIO-ED2?

Yes, we agree.

Given that SW 1-in-20 costs are dependent upon severe weather being experienced, it is reasonable for the associated costs to be treated as variant allowances. This will ensure that customers only fund the costs incurred by licensees and prevents windfall gains or losses for DNOs.

The process for this should be mechanistic, to avoid unnecessary regulatory burden.

Core-Q56. Do you agree with our proposal to not set a cap for the amount that DNOs can adjust their allowance by, in the event they experience a SW 1-in-20 storm?

Yes, we agree.

It is unreasonable to expect licensees to take on the risk of dealing with excessive severe weather. It is widely recognised that the frequency and intensity of storms is increasing in the light of climate change. This means that more storms may be experienced in the future.

Storms are outside of the control of DNOs and therefore the full costs of SW 1-in-20 events should be recoverable.

Core-Q57. Do you agree with our proposed approach to the physical site security re-opener?

Yes,

The requirements for national security of critical infrastructure may change and DNOs should be able to respond to enhanced government requirements.

There should be no materiality threshold for activation of the re-opener, given the importance of ensuring that critical electricity supplies are maintained.
Core-Q58. Do you agree with our proposed approach to the ESR re-opener?
Partly. We agree that there is a need for the re-opener, given that current requirements are uncertain. We also agree that there should be no materiality threshold for activation of the re-opener, given the importance of being able to carry out an Electricity System Restoration following a widespread power disruption. The timing of the window is proposed to be in June (during the regulatory reporting season). It would be more appropriate to have it at some point between October 2024 and March 2025.
Core-Q59. Do you agree with our approach to fund DNO telecoms resilience activities through baseline allowances?

WPD agree with Ofgem's approach to continue funding DNO telecoms resilience activities through baseline allowances, however WPD disagree with the current level of baseline funding that has been awarded to us for telecoms resilience activities.
 	
The reason for WPD disagreeing on the proposed level of baseline funding that has been proposed is detailed below:
 	
• The recently published Storm Arwen report by BEIS[10] clearly mentions the need for DNOs to maintain resilient communications. Resilient communications is not available as a bought in solution, therefore Ofgem must ensure that funding is made available to DNOs to continue telecoms resilience activities.
 	
• By the end of 2025 there will be no commercially available power resilient telecoms solution available from commercial providers and so there is a clear need for DNOs to invest in private telecoms networks. This is due to two key activities within the UK telecoms market:
    ○ There will be an increase in funding requirements early on in RIIO-ED2 due to the PSTN switch off. The announcement by BT Consumer that the PSTN switch off was being reviewed following on from Storm Arwen does not mean that Openreach are delaying this work; Openreach have confirmed that the switch off will continue and will still be completed by the end of 2025. This has been confirmed to WPD. The investment required by WPD for this has been included in EJP036, which is currently 'partially justified'. This investment is crucial for WPD to maintain power resilient communications.
    ○ In addition to the PSTN switch off, the mobile network operators have confirmed that they will be switching off various 2G and 3G networks during ED2[11], this will also have an impact on DNOs. This project is known within the telecoms industry as the Sunset project. Mobile

[10] BEIS Report page 16 - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1081116/storm-arwen-review-final-report.pdf
[11] OFCOM Report - https://www.ofcom.org.uk/phones-telecoms-and-internet/advice-for-consumers/advice/3g-switch-off

operators are not being prescriptive but have quoted as starting in 2023. We have not requested specific investment in RIIO-ED2 for this, but we are highlighting the issue to demonstrate the need to ensure sufficient funding is made available to DNOs for telecoms resilience in RIIO-ED2.
 	
• Regarding the spectrum being made available for the UK utility industry:
  o Through the work of the Energy Network Association's (ENA) Strategic Telecoms Group (STG) engagement is continuing with both DCMS and OFCOM to enable spectrum to be made available for the UK utility industry. During these discussions they have advised the group that they are looking to make an announcement on this shortly. In addition, this group has already started discussions on how this network could be rolled out for the UK utility industry.
  o We submitted EJP032 for this. We understand the policy reasons for this being disallowed, but if the funding for LTE is not made available, we will be requesting an additional £11m investment in the EJP addendum to maintain our current networks until LTE is made available.
  o Funding should also be allowed within RIIO-ED2 for further development on the proposed LTE system for the UK utilities (we have included this in the addendum above). WPD has been at the forefront of the LTE trials and there is still further work that needs to be carried out to enable quick deployment of the proposed private LTE network for UK utilities when the spectrum is made available. The findings from this development work have been shared with all interested parties across the UK utility industry.
  o Should the spectrum become available during RIIO-ED2 and an agreement between UK utilities made, then a reopener should be allowed to enable this to continue.
 	
It is due to these points that WPD believe the level of baseline funding that has been proposed by Ofgem needs to be increased. WPD is providing EJP addendums to request increased funding is made available.

Core-Q60. Do you agree with our proposal to assess the cyber resilience IT and OT plans against our BPG and RIIO-2 re-opener guidance?
Yes. The WPD Cyber resilience IT and OT submissions drew on, amongst other sources, the information in the BPG and RIIO-2 re-opener guidance.
Core-Q61. Do you agree with our proposed re-opener windows for cyber resilience OT and IT?
No. The provision of only one year's worth of allowances in year 1 of the price control is not conducive with delivering an effective and efficient five year cyber security strategy for many reasons. Firstly, without the confidence of getting funding for year 2, short term contracts and engagements will be put in place rather than having 5 year contracts with the cost reduction benefits of having five years' worth of security.

Secondly to recruit, train and develop resources based on a year to year basis is not workable. With the risk of cyber-attack being high, it is essential that our strategy is robust and delivered in full in order to protect our customers from data loss and power outages and hence full confidence in having available funding is critical to achieve this level of protection. In order to ensure that reduce the cyber risk impact on our customers during RIIO-ED2 and have systems designed to enable NIS compliance, we ask that Ofgem provides the full 5 year allowances as ex-ante and applies an UIOLI uncertainty mechanism to protect the customer from paying for cyber security measures which are not put into place.
Core-Q62. Do you agree with our proposal to apply a UIOLI allowance to cyber resilience OT to manage the uncertainty around costs?
Yes. We agree with the proposal to apply a UIOLI allowance but cannot see how this will work with the current planned year 1 and year 3 reopeners, as many cyber OT related projects will be part of multi-year programmes and the uncertainty the reopener brings, in relation to future funding as well as the additional work a reopener creates, will significantly impact our abilities to reduce cyber risk and meet full NIS compliance as originally planned in RIIO-ED2. Therefore we require OFGEM to fund cyber security in full as an ex-ante allowance and utilise a UIOLI mechanism to manage an uncertainty.

7. Delivering at lowest cost to energy consumers

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

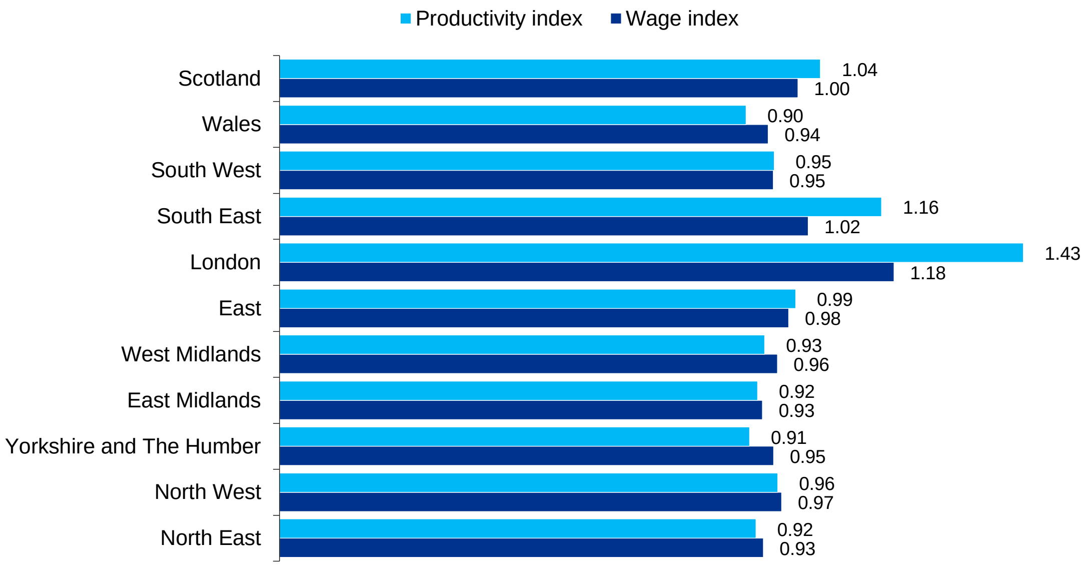
Regional wage adjustment

We disagree with the proposed regional wage adjustments for three reasons:

First, **lack of balance**. The proposed adjustments for regional wage take into account one factor (i.e. regional wage) but disregard factors that benefit denser, higher wage regions. Such factors include **higher labour productivity** (discussed below), **benefits from economies of density** (e.g. flexible labour markets - easier to hire specialised labour and to fill in part time jobs; access to a greater and more competitive pool of subcontractors) and avoiding **additional costs incurred in sparse regions** (e.g. additional travel costs).

Recent ONS data on regional labour productivity show that, on average, labour productivity is higher in London and the South-East.[12] The data shows that in London labour is on average 1.5 times more productive than elsewhere in GB, and in the South-East the ratio is 1.2. These are greater ratios than the regional wage ratios calculated by Ofgem. The two charts below show productivity and regional wage indices in UK regions. The correlation between the indices is 0.975.

Figure: Wage and productivity across GB regions



Source: Productivity index: analysis of ONS labour productivity data. Wage index: Ofgem.

Second, **lack of econometric evidence** that regional wage is a material cost driver. If regional wage differences had a material impact on DNOs' costs, as the scale of proposed adjustments suggests, we would expect it to be a statistically significant cost driver in the econometric models. The econometric evidence suggests that this is not the case; not only is the index of regional wages not a statistically significant cost driver, it also has a counter-intuitive negative sign.
That does not mean that wages, or regional wages, are not a material cost driver of DNOs' totex. It means that in the context of the models proposed, the variable is not

[12] See Regional labour productivity, UK - Office for National Statistics (ons.gov.uk).

needed. It is either sufficiently captured by variables in the model, offset by variables excluded from the model, or not a material driver of cost differences across DNOs to begin with.

The need to get this right should not be underestimated. The proposed regional adjustments have a material impact on all DNOs. This impact is not only on the calibration of model parameters, but also on the calibration of the efficiency benchmark, because the DNOs that receive the largest regional wage adjustment (i.e. LPN and SPN) are the ones that determine the efficiency benchmark for the sector (LPN and SPN have the lowest efficiency score by a large margin in every totex model. What helps them achieve such large margins is that they receive the largest regional wage adjustment per customer, and are amongst few DNOs to also receive company specific adjustments. One of these adjustments, incidentally, is justified by the fact that a low number of their employees actually live in London (para 7.58), which appears in contrast to the need for a large regional wage adjustment in London.)

Finally, we note that the models improve (e.g. in terms of R-squared) when the regional wage adjustments are removed.

Third, Ofgem's ASHE-based index captures regional wage differences within standard occupational codes (SOCs). The index does not control for industries and/or companies. As such it is expected to **overestimate any London or other regional weighting** paid within a company for direct labour across regional offices (we focus on direct labour as the choice between direct and contract labour is under management control and at any rate wages of direct labour are assumed to reflect wages of contract labour).

The industry, or companies, mix between London and the rest of the country is different, with London having a disproportionate share of high-paying industries/companies such as finance, pharmaceuticals and technology, which in turn have comparatively higher salaries for all professions. An index that controls only for occupations would therefore overestimate regional wage differences relevant for a DNO.

On the basis of the above, we consider that regional wage normalisations are not required. If Ofgem were to make regional normalisation, it should be based on two regions (London vs the rest) where the size of the adjustment is based on evidence of London weighting from *within* companies or organisations, and this evidence of London weighting should then be attenuated to reflect the offsetting factors discussed above.

Company specific factors

WPD is one of only two companies that did not make any regional or company-specific factor claim. This is not because there are no unique circumstances in any of our regions, but because we took a balanced approach, recognising that all DNOs have specific factors that increase costs relative to other DNOs, but also favourable factors that reduce costs relative to other DNOs.

Given the results of the totex models which identified our South West region as very inefficient, we may re-consider our position. We are aware, for example, that sparsity in the region adds to our operating costs compared to our Midlands networks. Given that South West is an outlier in Ofgem's totex models, we expect Ofgem to reassure itself that the results are credible, and to investigate if sparsity needs to be considered in the models.

We are not convinced that claims submitted by UKPN for Nature of Streets and Network-Specific Factors are balanced and warranted. For example, the additional costs UKPN is arguing to incur due to the nature of streets or due to the volume and size of cable pits and link boxes may already be captured in the cost drivers: through MEAV, which gives a high weight to underground assets, of which London has a very high proportion; and through the number of customers, which tend to be correlated with large urban areas.

Likewise, the fact that UKPN requires specialist resources to work in tunnels may be double counting the regional wage adjustment. As we said above, ASHE SOC index compares occupations across regions, and the significantly higher index in London partially reflects different nature of work and businesses in London for the same occupation. In this case, the high index for London reflects the higher pay for the arguably large proportion of tunnel workers in London.

Last, we urge Ofgem to ensure that only the incremental costs of these unique factors are removed from cost assessment models. If the entire cost of these unique factors is removed, there would be a mis-match between the cost and cost driver.

Exclusions

Ofgem sets a high bar for cost exclusions, stating that "costs should only be excluded when there is a strong rationale for doing so".

We have reviewed the current list of exclusions and we consider that further exclusions are needed. Through CAWG discussions, we have consistently been of the view that totex models require more cost exclusions in ED2, given the context of this price control and the importance of enabling the transition to net zero.

We also have observations on the calculation of the current exclusions, and note some inconsistencies across DNOs.

Green recovery

Ofgem states that this is an exclusion from totex modelling, as it had already been separately assessed and approved. We agree with this approach; however the adjustment has not been made in the totex models. As discussed in our SQs (WPD028 and WPD062) green recovery is embedded in CV1 data in our BPDT submission. In the SQ response, Ofgem has acknowledged this and stated that they "will review all DNOs submissions and correct where appropriate ahead of Final Determinations."[13]

Rising and Lateral Mains

We agree with the exclusion of these costs from totex modelling, but believe that in line with the costs exclusions, the associated assets should also be removed from the MEAV used in the totex benchmarking (see Q64 response).

Streetworks

We agree with the exclusion of this activity from Totex modelling, but disagree with the values used to calculate the exclusion.

The current exclusion is based on the values of Streetworks cost type in the C1 cost matrices. However DNOs have also submitted detailed memo tables M9a and M9b, which include significant additional costs associated with Streetworks that are not necessarily disclosed as Street Works, but as Contractors and Labour instead. We

[13] Note it also needs to be determined how this is to be funded in RIIO-ED2 and thus how the expenditure is reflected back in the RIIO-ED2 PCFM. This issue has been raised through the Licence Drafting Working Group

believe that the memo table costs are a better reflection of the exclusion that should be applied and better reflect the differences across regions (differences which are visible across WPD own 4 DNOs). We have raised this issue in SQ WPD032.

While we fully support an approach which does not include comparative benchmarking across DNOs and which fully recognises the very different policy environment across regions, we do think there should be some form of qualitative review between DNOs before exclusions are made to ensure consistency of reporting. We note that NPG has a large exclusion compared to WPD (and other DNOs) when there is no perceivable policy influences in these areas.

These issues, and their impact on disaggregated modelling, are discussed further in the response to Q104.

<u>Cyber Security</u>
Further consideration needs to be taken on the ED1 exclusions as there is inconsistency in reporting: 4 DNOs have reported costs from 2020 onwards only (when the requirement to separately identify cyber cost in RIGs reporting was established); only 2 DNOs have restated back to 2016. Therefore there may be inconsistency in ED1 cyber costs pre 2020, which needs to be resolved.

<u>Quality of Service</u>
In our response to Q49 we explain why Quality of Service costs should not be disallowed as proposed. If Ofgem decides to assess Quality of Service costs and make an allowance, as we believe it should, we consider that these costs should be excluded from totex models and assessed separately because these costs are not well linked to the cost drivers in the totex models (as specified in Table 24 of the Core Methodology).

<u>Other areas of exclusion</u>
Other potential areas of exclusion have been discussed in CAWG meetings. The Draft Determinations provide no further consideration of these areas that have been discussed in these meetings and the reasons that Ofgem consider that these have not met the criteria.

The following areas merit further consideration in Final Determinations:

<u>DSO</u>
Cyber security costs has been excluded from Totex modelling due to "significant change in the equivalent level of costs between the RIIO-ED1 and RIIO-ED2 periods". The same argument applies to DSO costs (as evidenced in memo table M19). This was raised in SQ WPD027.

We note Ofgem's response: "The option of excluding DSO costs from totex modelling was considered and discussed at CAWGs, but discarded to avoid compromising the nature of totex modelling itself. Nonetheless, we welcome further feedback through your response to the consultation on whether and why you think DSO costs should be excluded from totex modelling". The rationale and decision to exclude costs from Totex should be based on clear criteria, and not set or led by the concept of totex modelling itself.

<u>LRE</u>
We have previously suggested that this could be excluded from Totex on the basis that as an entire category it is excludable, and a disaggregated model has clear advantages over totex in this area of spend. They are costs that are changing significantly in total between RIIO-ED1 and RIIO-ED2.

Remote generation opex We propose that because these costs are only seen in 3 DNOs, not explained by a cost driver in a totex model and are easily excludable, these should also be an exclusion in the totex models. Other DNO suggested activity areas Other areas that have been suggested as exclusions through CAWG are Flooding, Smart metering roll-out, Diversions, Environment, BT21C and IT&T (albeit that this is covered to some extent by Cyber Security and DSO). **Other adjustments** The criteria for when a bespoke output is an exclusion in Totex is unclear. We note this with reference to the treatment of CVPs. Our CVP5, the successful CVP5 with reward, is adjusted, which we agree with. However there are differing treatments for CVPs which are accepted with no reward. Some are included in baseline (and subject to cost assessment); others are subject to technical assessment (and are therefore excluded from Totex). The criteria for when such adjustments are made should be clearer. In our response on CVPs[14], we state that all 4 WPD CVPs which have been accepted are going above baseline, which should merit further consideration for exclusion from Totex
Core-Q64. Do you agree with our approach to totex benchmarking?
Totex models have become a standard tool for cost assessment in price determination in the water and energy sectors. We recognise that totex models have a role to play, and can add useful high level view of relative efficiency. While we accept their role, due to their high-level cost drivers, totex models are more useful when totex is expected to remain largely the same over time. Due to the expanding functions of DNOs in ED2 (e.g. due to their role in the transition to net zero, the process of digitalisation and the rapidly evolving DSO function) totex models would struggle to capture these changes, even if the specification includes a single demand or workload variable. We have consistently been of the view that more weight should be put on a disaggregated approach to cost assessment given the context of this price control and the importance of enabling the transition to net zero. We have also been of the view that the totex models would require more cost exclusions this time around, including, possibly, the removal of load related expenditure from totex models (see our response to Q63). Below we set out our view on totex models related to (i) the use of MEAV as a cost driver (ii) our view on models' specification. **MEAV is not an appropriate cost driver** MEAV is the dominant cost driver in Ofgem's proposed totex models, weighing over 70% in the composite scale variable (CSV). MEAV is also the most widely used cost driver in the disaggregated approach. We consider that MEAV is a flawed measure of DNOs' scale.

[14] Annex 6, WPD, Response on CVPs

MEAV is supposed to represent the replacement cost of a DNO's existing network with 'modern equivalent' assets. MEAV is endogenous – the collection of assets on a DNO's existing network is to some degree a result of management decisions.

Endogeneity is not our main concern with MEAV. Our main concern is that MEAV gives weight to different assets, based on their replacement costs, and these weights have no relation to the costs companies incur by the asset.

For example, underground cables have a much larger weight in MEAV compared to overhead lines because their replacement cost is 4-8 times higher. Cable assets represent 66% of MEAV compared to 13% of overhead line assets. However, the replacement cost of assets (in effect, their weight as a cost driver) is not related to many costs in totex. Significantly high replacement cost of underground cables is not justified for inspection and maintenance costs – overhead assets require more of this activity than underground cables. Significantly higher weight on underground assets is not justified for tree cutting costs – only overhead assets drive this activity. Significantly higher weight on underground assets is not justified as a driver for indirect costs. And significantly higher weight on underground assets is not even justified for asset replacement costs – overhead assets are replaced more frequently than underground assets. On an annualised basis, the replacement costs of underground cables and overhead lines would be closer to one another relative to the non-annualised replacement cost used in MEAV.

A MEAV skewed by high replacement costs of underground cable is therefore not an appropriate cost driver for totex or in fact for any activity. The use of MEAV distorts benchmarking results (all else equal, in favour of companies with a large share of underground assets). This is part of the reason our South West network appears inefficient in Ofgem's MEAV-based models.

Given its dominance in cost assessment and price determinations, we recommend that the measure of MEAV as a cost driver is reviewed by Ofgem and the sector. Ror RIIO-ED2, we recommend putting less weight on MEAV and instead a higher weight on more relevant and objective measures of scale such as network length and customers.

Putting aside the above concern with MEAV, we do not agree with two other aspects:

Rising and lateral mains (RLM). MEAV includes RLM assets despite the direct costs of these assets being excluded from totex. That is, the asset is included in the cost driver, but the cost does not include the asset.
Ofgem's rationale is that there may be some residual costs in totex, for example in CAI, that are related to RLM assets.
Because the direct costs of RLM assets are removed from totex, leaving RLM assets in MEAV would result in a large disproportionate impact of these assets on MEAV compared to their small impact on totex. This distorts modelling results. RLM assets should be excluded from MEAV. If Ofgem consider the issue is material for any given company, as adjustment outside of the model may be appropriate.

Protection and civil works assets. At RIIO-ED1 protection and civil works assets were excluded from MEAV due to concern about the quality of data related to them. For ED2, Ofgem says "It is our view that DNOs have had sufficient time since the start of RIIO-ED1 to improve the robustness and quality of the data they report against these asset categories, and the same inconsistencies that we observed when setting RIIO-ED1 should no longer exist."[15]

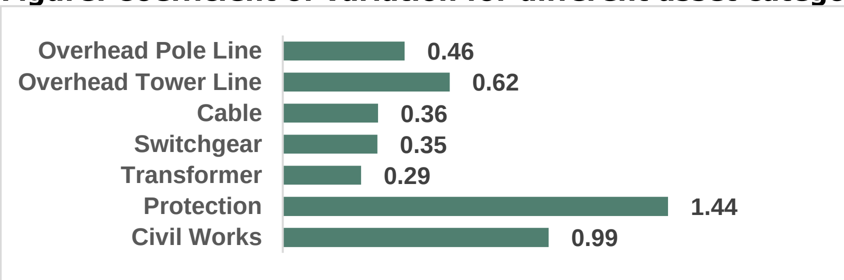
[15] RIIO-ED2 draft determinations, core methodology document, paragraph 7.119.

Ofgem does not explain what evidence led to its view that the data has improved and is sufficiently robust for inclusion in MEAV. It says that 'inconsistencies… should no longer exist'. That they should not exist does not mean that they do not exist.

We have concerns with the robustness of the data related to these assets. For example, our records of protection equipment (pilot wires) do not enable us to report their volumes. It would require us to vectorise legacy drawn elements.

Reviewing the data reveals large variation in protection and civil works replacement costs across companies. The chart below shows that the variation of MEAV for protection and civil works equipment is significantly larger than for other asset groups. This is not an indication that the data is robust.

Figure: Coefficient of variation for different asset categories in MEAV



Between protection equipment and civil works the bigger distorter of MEAV is protection equipment. Some DNOs have extremely high values of protection equipment. These values have a large impact on benchmarking for the entire sector. We consider that protection and civil works assets ought to be removed from MEAV because of (i) high variation/lack of confidence in the data (ii) a larger degree of company control over these assets compared to cables and lines. As with RLM, rather than distort benchmarking with their inclusion in MEAV, Ofgem may provide an out of model adjustment where appropriate based on robust evidence.

Comments on Ofgem's proposed totex models

Lower weight to MEAV. Following our comments above, it would be appropriate to remove or reduce the use of MEAV in totex models. Network length, as the most fundamental and relevant measure of the DNOs' scale should have a significant weight in the CSV.

We propose a CSV that uses MEAV, faults, peak demand and network length at the respective weights of 25%, 10%, 20% and 45%.

We consider that this CSV, with the weights proposed, can be better justified against the activities in totex. It also results in improved models, for example in terms of basic diagnostics (e.g. a higher R-squared) as well as a more reasonable spread of efficiency scores.

The use of a time dummy for RIIO-ED2 instead of time trends. Totex models 1 and 2 include a full period and a forecast period time trend. Statistically, a time dummy for the RIIO-ED2 works better than the time trends proposed. It is more significant, improves model quality and, in the case of totex model 2, makes the specification pass the RESET test instead of failing it.

Despite the superior statistical performance of the RIIO-ED2 time dummy, Ofgem prefers using the time trends as they are "more consistent with our prior expectations for why we wanted to control for time effects within our totex models” (Core methodology document, paragraph A7.4, page 403).

We do not agree with this. We consider that a time dummy for RIIO-ED2 is more appropriate than the time trends proposed. A RIIO-ED2 time dummy captures the step change forecasted in totex at RIIO-ED2, while the scale and demand/workload variables capture the steady year-on-year progression in the level of cost.

We also refer to a comment on the RIIO-ED2 dummy made in CAWG 23: “Including a dummy variable for the ED2 period improved model performance in terms of R2 and efficiency scores, but effectively results in an upward step-change in modelled totex for ED2 relative to ED1. The economic and regulatory justification for allowing this may require further consideration.” (Cost Assessment Working Group, Meeting 23, slide 14).

We note that from an economic and regulatory perspective, there is no difference between the use of a ED2 time dummy and the use of time trends. Both types of models ‘allow’ DNOs projected totex to play a role in setting DNOs’ allowances for ED2. The ED2 time dummy is in effect simply the average of the forecast time trend, even if in practice is leads to slightly different (more accurate) results because it fits the data better.

We therefore consider that the RIIO-ED2 dummy should be used as it aligns with the expected change in totex, performs better statistically and results in a more accurate model.

Totex model 2. Totex model 2 fails the RESET test, which is an indication of potential misspecification, often pointing at missing non-linear terms. Ofgem emphasises the importance of the RESET test in paragraph 7.100 only to then argue, when defending totex model 2, that the test is not critical (paragraph A7.4). Ofgem also argues that failure of the RESET test often points to missing non-linear terms, the appropriateness of which was ’significantly questioned’ by the CMA. We disagree. The CMA did not question inclusion of non-linear terms in the 2015 Bristol Water redetermination. The CMA questioned the usefulness of a translog specification, which uses a number of quadratic and cross-product (i.e. interaction) terms in the model. The CMA would not ‘significantly question’ the introduction of a non-linear term where appropriate.

Against this context, a squared term of ‘capacity released’ can be considered for totex model 2.

Totex model 3. Totex model 3 plays a key role in Ofgem’s cost assessment approach, given its equal weight amongst the totex models and its key role in determining the demand driven adjustment. Yet, the model has the lowest R-squared and widest range of efficiency scores compared to the other two totex models and compared to totex models more generally (i.e. in previous price controls and other sectors – for comparison of model diagnostics see our response to question 108).

On a more pragmatic level, we consider that heat pumps (HPs) and electric vehicle (EV) chargers should not be equally weighted in the composite LCT uptake variable. The respective weights should be linked to the degree that HPs and EVs drive costs, which, in turn, should reflect their contribution to peak demand.

Consideration should be given to ensuring any external datasets used are most up to date. FES2022 datasets would represent the most recent Government ambitions and more accurately reflect the current outturn position of connected LCTs.

HPs have a higher contribution to peak demand due to the higher energy requirement across the year, the concentrated seasonal requirements across the winter and the higher likelihood of coincident behaviour for all devices to operate simultaneously. It is particularly important to consider levels of diversity observed across population levels representative of LV feeders. Over half of our LV feeders[16] have 5 customers or fewer connected, so using large diversity assumptions from urban areas is not suitable. This is particularly important considering heat pump rollout is likely to be most economically advantageous in rural, off-gas areas. Our evidence shows that EVs have a peak of 1.3kVA and HPs have a peak of 2.9kVA. This would support a weight of 30% for EV charge and 70% for HPs.[17]

Random effects model. Naturally, when dealing with panel data, econometric practitioners use a panel data estimation method. The most common ones are the 'fixed effects' and the 'random effects', with the latter being typically more suitable in regulatory settings where the sample is small and scale drivers do not vary much over time. We understand the desire for simplification that led to Ofgem opting to use the OLS estimation method (which does not recognise the panel structure of the data hence tends to be less precise than panel data methods). Moreover, we understand that OLS can have small sample advantages over the random effects method.

When looking at the difference in results between OLS and random effects models, we find that the differences for totex models 2 and 3 are very small. On the basis of materiality alone the use of the simpler OLS method is appropriate. However, for totex model 1 the difference is more material. We consider that there is a case for using the results of a random effects model for totex model 1.[18]

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

The cost assessment for Primary reinforcement is solely based upon ratio benchmarking for both unit costs and volume adjustments.

Primary reinforcement can have a wide range of solutions. For example the resolution of a capacity constraint may be resolved through the changing of one span of overhead conductor or may require many km of cable. The use of ratio benchmarking reduces allowances to median levels and may therefore be excluding valid (albeit more expensive) activities.

While data structures in the Business Plan Data Templates allow activity category specific benchmarking (to compare similar activities), benchmarking is hampered by relatively low volumes of activity in each category.

We note that review of Engineering Justification Papers has not had a direct impact on the disaggregated cost benchmarking and is solely used as a cross check of the results.

Green recovery

The assessment approach needs to take into consideration green recovery expenditure and volumes. As discussed in the WPD SQs (WPD028 and WPD062) green recovery is embedded in CV1 data in WPD's BPDT submission. In the SQ

[16] See page 8 of our Smart Meter Data Privacy plan: https://www.westernpower.co.uk/downloads/595138

[17] For comprehensive evidence see our DFES customer behaviour assumptions report. Evidence on HPs page 75 and on EVs page 61.

[18] We note that the Breusch-Pagan test, often used to decide between OLS and random effects, concludes in favour of the random effects method.

response, Ofgem have acknowledged this and stated that they "will review all DNOs submissions and correct where appropriate ahead of Final Determinations."
Core-Q66. Do you agree with the application of a volume adjustment based on the industry average ratio of forecast capacity added relative to the forecast demand growth above firm capacity? If not, what do you consider to be a better approach to assessing the efficiency of a DNO's proposed workload for primary network reinforcement?
The application of a volume adjustment based upon the ratio of forecast capacity added, relative to forecast demand growth above capacity is reasonable. However, it does not capture all the load growth that is leading to the need for reinforcement. Due to Primary Reinforcement projects generally having long timescales the activity is triggered before the existing full capacity is utilised. This means the load growth in totality should be considered, not just the growth above firm capacity.
Core-Q67. Do you agree with our proposed assessment approach for secondary reinforcement?

The overall approach of linking the need for reinforcement to drivers based upon LCT growth is reasonable, but the modelling could be made more representative by more disaggregated benchmarking.

<u>Volume Benchmarking</u>

The benchmarking derives volume based cost adjustments by applying an adjustment factor to the modelled costs derived from unit cost benchmarking. While there are seven cost areas subject to volume based adjustments, Ofgem only calculates three adjustment factors as per the table below.

Cost area	**Volume factor**	**Cost driver**
Pole mounted transformers	Combined gross MVA added for both pole mounted and ground mounted transformers	Forecast MW of LCT connections
Ground mounted transformers	Combined gross MVA added for both pole mounted and ground mounted transformers	Forecast MW of LCT connections
LV circuits	Combined LV & HV circuit length	Forecast number of LCT connections
HV circuits	Combined LV & HV circuit length	Forecast number of LCT connections
Proactive OH services	OH & underground unlooping interventions	Forecast number of EV and heat pump additions
Proactive UG services	OH & underground unlooping interventions	Forecast number of EV and heat pump additions
Proactive switchgear	OH & underground unlooping interventions	Forecast number of EV and heat pump additions

There are issues with the combination of pole mounted transformers with ground mounted transformers and with the combination of LV circuits with HV circuits.

Volume Benchmarking – Pole Mounted and Ground Mounted substations

By combining pole mounted and ground mounted transformers, Ofgem is mixing dissimilar activities which can be skewed if the blend of these activities is different across DNOs. Assuming that a typical pole mounted transformer is rated at 100kVA and typical ground mounted is rated at 800kVA. Each intervention on a ground mounted transformer provides 8 times the gross kVA, so a DNO with more activity on ground mounted substations will skew the benchmark in favour of ground mounted transformers.

We therefore propose that pole mounted and ground mounted transformers should be separately assessed. Both can still use the MW of LCT connections as the cost driver, but separate ratios and industry means should be derived for each.

Volume Benchmarking – LV & HV Circuits

Ofgem has combined LV and HV circuits together and used the number of LCT connections as the cost driver. By combining LV and HV circuits, Ofgem is mixing dissimilar impacts from LCT volumes. Far fewer LCT volumes can be accommodated on LV circuits than on HV circuits and this means that there is a different relationship between LV circuits and LCT volumes compared to HV circuits and LCT volumes. The benchmarking can be skewed depending on the blend of LV and HV circuits reinforcement requirements across DNOs.

We therefore propose that LV and HV circuits should be separately assessed. Both can still use the number of LCT connections as the cost driver, but separate ratios and industry means should be derived for each.

Volume Benchmarking – Proactive OH service, UG service and switchgear (cut-outs)

Ofgem has combined OH services and UG services to derive the adjustment ratios for OH service, UG service and switchgear (cut-outs).

For these categories there is more of a direct relationship between the number of services and the number of EVs and heat pumps (i.e. for every 100 EVs or heat pumps there will be a proportion that need a service to be unlooped).

The derivation of the adjustments factor using combined volumes of OH and UG service is reasonable. In this case, we propose no change to the benchmarking methodology.

Volume Benchmarking – Gross vs Net Benchmarking

For substation reinforcement the volume factor (numerator) for the adjustment factor is based upon the gross capacity added. Gross capacity added misrepresents the benefit that is being delivered from the intervention.

Assuming that a typical pole mounted transformer is rated at 100 kVA and typical ground mounted is rated at 800kVA. An increased requirement of 100kV would lead to the installation of a 200kVA pole mounted and 900kVA ground mounted unit. Both would provide an extra capacity of 100kV, but the gross amount installed on the ground mounted is significantly higher.

Using the gross amount provides a measure of installed capacity not additional capacity.

This is inconsistent with the cost driver being used (forecast MW of LCT connections). The additional load created by LCT connections requires additional capacity on the network. Whether that increase in capacity is delivered via a small pole mounted transformer or a large ground mounted transformer is largely irrelevant. It is the extra capacity that is important not the size of the equipment providing that extra capacity. It is therefore more appropriate to use net increase in capacity rather than gross installed capacity. <u>Green recovery</u> The assessment approach needs to take into consideration green recovery expenditure and volumes. As discussed in the WPD SQs (WPD028 and WPD062) green recovery is embedded in CV2 data in WPD's BPDT submission. In the SQ response, Ofgem have acknowledged this and stated that they "will review all DNOs submissions and correct where appropriate ahead of Final Determinations."
Core-Q68. Do you agree with the level of disaggregation and period of data used to calculate the unit costs listed in the table above for transformer reinforcement, circuit reinforcement and proactive service reinforcement?
The level of disaggregation of unit costs is reasonable as a specific unit cost is derived for each activity. Using RIIO-ED2 forecast data for substation and circuit work is also reasonable, given that historical data has not been reported. Using industry medians provides a reasonable level of benchmarking efficiency challenge for DNOs above the median. However, the use of expert view asset replacement costs for proactive service work is not appropriate. <u>Issues with proactive service unit costs</u> By using expert view asset replacement unit costs, Ofgem is making an assumption that proactive service unlooping is equivalent to asset replacement service work. This is not the case. There are various complexities about unlooping which are not encountered under asset replacement, such as the disconnection of cable between properties, installation of a new cable route, potential changes to the service position due to accessibility for the new dedicated service. For this reason it is inappropriate to use the asset replacement unit cost. The benchmarking for proactive services should use RIIO-ED2 industry median unit costs as per the other secondary reinforcement cost areas.

Core-Q69. Do you agree with our proposed assessment approach for fault level reinforcement?
The various issues that Ofgem has revealed with the data for ENWL and SSES illustrate that the benchmarking of fault level allowances using unit cost benchmarking is subject to inconsistencies. Some of these inconsistencies are down to interpretation of reporting requirements (as is documented for ENWL), but by far the greatest issue is the range of scope of works that could be carried out under an activity. Ofgem's testing of various levels of aggregation illustrates that a disaggregated activity based benchmarking process is the least worst option. However, the implicit assumption is that the units are comparable. This is not the case. For fault level reinforcement there is a range of scenarios that can lead to a different work mix and unit cost depending on the types of project, substations / circuits impacted and scope of works for individual schemes. The following are scenarios that might result in significant scope variations: • The number of items that need to be changed can vary. Switchboard issues may require a small number of circuit breakers to be changed for a small rural substation or may require high volumes of circuit breakers to be changed for a large urban substation. Both will have a unit of one project, but the costs will be vastly different. Benchmarking these will bias against work on the large urban substation, even though there may be a strong needs case for the work and the proposed costs are reasonable. • The scope of works can vary. Some air insulated EHV and 132kV sites will necessitate a wholesale rebuild if the associated equipment e.g. busbars are below the required minimum fault withstand capability, whereas other sites might only necessitate the replacement of the circuit breakers and disconnectors. This leads to more extensive civil works and site reconfiguration compared to just replacing individual components. • The approach to carrying out the work can vary. In some case there is a need for a wholesale or partial offline build of some of the EHV or 132kV bays as it is not always possible to carry out in-situ reinforcements of the various components due to safety proximity and outage restrictions. Given the scope for distortions by using unit cost benchmarking, we propose that more use should be made of separate qualitative assessments, using the Engineering Justification Papers for individual schemes. These should be separately assessed (in a similar way to the ENWL and SSES adjustments) and excluded from the cost benchmarking, allowing the cost benchmarking to deal with the residual volumes and costs.
Core-Q70. Do you agree with our proposed adjustments to account for outlier volumes data for ENWL and SSES?
Given the range of scope of works for dealing with fault level reinforcement issues, we recognise a need for bespoke assessment of special circumstances.

We advocate a greater use of bespoke assessment for fault level reinforcement projects. As detailed in our response to Core-Q69, there is a wide range for the scope of works that may be required and therefore using unit cost benchmarking that assumes the projects are the same does not take account of the variability in scope that is necessary. We propose that the qualitative assessment of Engineering Justification Papers should be used to assess the needs case, scope of works and associated costs for projects where such details have been provided by DNOs. The associated volumes and costs should be removed ahead of benchmarking the remainder of volumes and costs. This means that final modelled disaggregated allowances will be based upon a blend of qualitative assessment for where engineering justification is available and the unit cost benchmarking of the remainder. While there may still be variability in the scopes of works in the remaining cost subject to benchmarking, these will relate to lower values and have a smaller distorting effect.
Core-Q71. Do you agree with our proposed assessment approach for connections?
No, we do not agree with the proposed assessment approach used for Connections using MPANs instead of projects. We believe that using projects is more reliable as it's less prone to impacts from competitive market changes. For example if we forecast to connect 500 MPANs on one project but the main work to carry out the connection is carried out by an IDNO we would report 1 point of connection (POC) and one Project, whereas if we did the work it would be reported as 500 MPANs. Counting projects is the only consistent measure for DNO activity. Connections activity is dependent upon customer requirements and therefore the volumes are uncertain. We understand from bilateral discussions that connections will form part of the load related reopener and therefore any volume variations that impact expenditure should be covered by the re-opener provided the materiality threshold is met. We believe that a projects volume driver is a more consistent measure as opposed to an MPAN volume driver. The inclusion of connections in the load related re-opener needs to be explicitly stated to give DNOs confidence that variations in expenditure caused by changes to customer activity can be recoverable.
Core-Q72. Do you agree with our proposed assessment approach for NTCC expenditure?
Yes, we are supportive of the proposed qualitative review. We think this is appropriate given the low volume of schemes. We also agree with the exclusion of this activity from totex assessment. We welcome the confirmation of this treatment in the errata published on the 14th July. Note that in SQs raised by WPD (WPD029, WPD030), we highlighted that further updates are

still required to Table 24 in the Core Methodology and Table 36 in the Finance annex to reflect the correct treatment, as well as an amended PCFM Interface and PCFM files.
Core-Q73. Do you agree with our proposed assessment approach on asset replacement?

The assessment of asset replacement has been undertaken with separate activity volume assessment and unit cost assessment for each asset category. The scope of asset replacement works, and definition of asset categorisations, are sufficiently defined within Ofgem's BPDT guidance to ensure a degree of consistency that supports this approach to the assessment of asset replacement at an asset category level.

Volume Assessment

Volume assessment has been performed using both quantitative and qualitative analysis.

We are in agreement with the use of a tool-kit approach that considers a range of qualitative and quantitative evidence.

We are, however, surprised with the blunt treatment of programmes that are assessed as unjustified, where zero volumes are proposed even though there is acceptance of investment need.

For assets covered by Engineering Justification Papers (EJPs), the volume assessment is largely determined by the outcome of the review of EJPs:-

- if the EJP is considered justified then the submitted volumes are allowed;
- if the EJP is partially justified then the volumes allowed appear to be selected from the lower of the industry median run rate (based on % of population), submitted volumes or an ED1 Performance value determined by Ofgem's Engineering Hub; and
- if the EJP is considered unjustified then zero volumes are allowed.

We agree that where a relevant Engineering Justification Paper has been submitted, and the Engineering Justification Paper provides sufficient justification, it is appropriate that the submitted activity volumes are allowed as the modelled volumes.

We also agree that it is appropriate for modelled volumes to be based on technical assessment that considers both the volumes determined from quantitative analysis as well as other additional supporting evidence. However, for assets associated with partially justified Engineering Justification Papers the mechanistic selection of a 'lower of' appears to disregard:-

- any evidence that has been provided within the EJPs/ SQ responses;
- the information provided through the NARM tables in the BPDT; and
- DNO own run-rate.

We note that the applied approach (described above) differs from the description provided in the Core Methodology Document (e.g. use of age based modelling, use of 'ED1 Performance' values, information used in qualitative assessments etc.).

As a result of disregarding the DNO specific information that has been provided, the modelled volumes produced often do not reflect the individual DNO specific investment need. For example, volumes set at the industry median run rate will only reflect the size of the asset population, rather than the volume of assets within that population where there are condition related issues.

We suggest that any modelled volumes produced through the mechanistic selection of a 'lower of' the industry median run rate (based on % of population) or the ED1 Performance value are sense checked against the DNO specific information that has been provided, to ensure that they are reasonable volumes to address the investment need of the individual network. For example:

- the DNO's own run-rate provides a good indicator of the level of activity that is currently (and historically) required, as well as demonstrating levels of activity that are clearly deliverable; and
- NARM provides a recognised measure of asset condition, which is the predominant driver of Asset Replacement activity, and the associated condition based risk. NARM provides a clear measurement of the current condition of the network assets and a forecast of future deterioration. As a result it provides a useful tool to indicate both current condition based investment need and the likely investment need through RIIO-ED2. In addition, the risk measure improvements shown in the NARM tables of the BPDT can be directly compared to the cost of delivery enabling consideration of the cost-benefit justification for the DNOs submitted volumes, demonstrating the value that the interventions deliver to for customers.

Use of a 'lower of' approach, without subjecting the outcome to suitable qualitative sense check, will inevitably lead to overall modelled volumes for Asset Replacement that are insufficient to address the needs of the network assets. This approach appears to confuse 'low volumes' with 'efficient volumes' (as it fails to consider the assets risks retained on the network as a result of reductions in volumes of activity).

We would encourage greater consideration of the DNO specific evidence provided to sense check the suitability of modelled volumes produced using such a mechanistic approach to ensure that modelled volumes are set at suitable levels to meet network asset investment need.

We would also encourage the inclusion of a DNOs own run rate into the quantitative options used in the benchmarking process.

ED1 Performance

In some cases, the mechanistic approach to determining modelled volumes where EJPs are found to be partially justified leads to allowed volumes that are significantly below the investment need required to provide adequate network resilience for our customers.

In particular this has occurred in some of the instances where the modelled volumes have been set at the 'ED1 Performance' value.

'ED1 Performance' volumes are determined by application of a ratio to our ED2 submitted volumes. This ratio is calculated from comparison of the DNOs actual delivered volumes in the first six years of RIIO-ED1 with the RIIO-ED1 allowed volumes for the same period, thus calculating an ED1 forecasting error factor.

The application of the ED1 Performance factor effectively adjusts the submitted ED2 volumes proportionately to any degree of under-delivery in RIIO-ED1 compared to the RIIO-ED1 allowed volumes.

Our understanding is that Ofgem believes the 'ED1 Performance' values use historic data from ED1 "to provide an appropriate and deliverable volume allowance, which aligns with the licensee's delivery of these assets during RIIO-ED1". We understand that Ofgem believe these values represent "true investment need" and produce modelled volumes where there can be "a high degree of confidence in their deliverability".

In some cases the calculated 'ED1 Performance' volumes are producing modelled volumes that are significantly lower than the volumes that have been delivered in RIIO-ED1. In these cases, the modelled volumes do not align to (i.e. under-represent) the licensee's delivery during RIIO-ED1, where the licensee's track record of delivery in RIIO-ED1 clearly demonstrates that higher volumes can confidently be regarded as deliverable. Similarly, in these cases, the modelled volumes do not reflect the 'investment need' as represented by historical activity. For example, the table below compares the average annual volumes of LV pole replacement in our RIIO-ED2 business plan submission for WMID, with the actual annual volumes observed in the first six years of RIIO-ED1.

License Area	Asset Category	ED2 Submitted Removals (Average Annual)	Actual Delivered Removals in RIIO-ED1 (annual average)	Modelled Volumes ('ED1 Performance') in Draft Determination (annual average)	Modelled Volumes as percentage of ED2 submitted removals	Modelled Volumes as percentage of ED1 Actual Delivered removals
WMID	LV Poles	1936	2019	1152	60%	57%

In this example, it can be seen that the submitted volumes of 1936 removals per annum are slightly lower than the historic RIIO-ED1 average of 2019. However, the 'ED1 Performance' values that were applied in the volume assessment undertaken for Draft Determinations allow only 1152 replacements per annum. This is approximately 60% of both our submitted RIIO-ED2 volumes and our historic track record of delivery. This clearly does not align with our delivery during RIIO-ED1 or investment need.

Ofgem's quantitative analysis using industry run-rates (not shown in the table) determines 1893 replacements per annum based on the Industry Median run-rate. This is only marginally lower than our submitted volumes, showing that our submission is typical of industry rates of activity. However, the 'ED1 Performance' value of 1152 replacements per annum is again significantly lower than the Industry Median benchmark, indicating that it is significantly adrift from actual investment need.

The discrepancy between the 'ED1 Performance' volumes and the actual delivered RIIO-ED1 volumes arises because the ratio used in the derivation of the 'ED1 Performance' volumes would only be appropriate if the method of forecasting replacement volumes was unchanged between RIIO-ED1 and RIIO-ED2 Business Plan submissions.

Throughout the Asset Replacement engineering justification papers that we submitted with our RIIO-ED2 Business Plan, we have explained that we have used multiple types of information and analysis to inform our submitted RIIO-ED2 Asset Replacement volumes. As part of this process, we have considered DNO specific historical run rates (looking at both 3 year and 5 year rates where appropriate). This means that we have improved our forecasting using the learning gained in the RIIO-ED1 period and already taken account of our RIIO-ED1 performance within our submitted volumes. This, however, is not recognised in the ratio that has been applied in creating the 'ED1 Performance' volumes. As a result, any reduction in volumes in deriving the 'ED1 Performance' effectively 'double counts' the adjustment that was made in improving the forecast used in our RIIO-ED2 submitted volumes (compared to our RIIO-ED1 Business Plan forecast).

This can be illustrated by comparing the submitted ED2 volumes (expressed as average annual volumes) for poles with the average annual volumes that were included within our RIIO-ED1 Business Plan, as shown in the table below. For example, the table below shows for LV Poles in WMID that the annual average ED2 submitted removals are 44% of the annual average volumes that were allowed in RIIO-ED1 (as included in our RIIO-ED1 business plan forecast), however, the modelled volume of 1152 per annum (based upon application of the ED1 Performance ratio) are a further reduction, being 60% of the ED2 submitted volumes (26% of the ED1 allowed volumes).

License Area	Asset Category	ED2 Submitted Removals (Average Annual)	RIIO-ED1 Allowed Removal Volumes (annual average)	ED2 Submitted Volumes as percentage of ED1 Allowed Removals	Ofgem Modelled Volumes as percentage of ED2 submitted removals	Ofgem Modelled Volumes as percentage of RIIO-ED1 Allowed Volumes
WMID	LV Poles	1936	4379	44%	60%	26%

From the above, it can clearly be seen that the modelled volumes for pole assets are significantly below a level that reflects 'investment need' and the level that our track record shows is deliverable.

While we recognise that this is the result of our related engineering justification papers being found to be Partially Justified, we consider the resultant Ofgem modelled volumes to be inappropriate.

In particular, setting modelled volumes for overhead pole line assets that reduce the activity volumes significantly below the volumes that were delivered in RIIO-ED1 seems to conflict with the industry focus on overhead resilience that has resulted from recent reports on Storm Arwen.

We would encourage Ofgem to reconsider its process for application of the 'ED1 Performance' volumes and suggest that Ofgem should include a collar on the 'ED1 Performance' values that is set at the licensees actual RIIO-ED1 delivered annual average rate. This could then be considered alongside the other quantitative analysis (e.g. Industry Median run rate) when selecting the modelled volumes in cases where the related engineering justification papers have been considered as Partially Justified.

Following the bilateral meeting held with Ofgem's Engineering Hub on 17 August 2022, WPD provided a worked example of how the collar could be applied in various different circumstances.

<u>Engineering Justification Papers covering multiple cost areas</u>

A number of the submitted engineering justification papers cover:-

- multiple asset categories;

- multiple expenditure areas (i.e. Asset Replacement/ Refurbishment (NARM)/ Refurbishment (non NARM)); and/or
- multiple volume drivers leading to an overall volume forecast for a single asset category.

Where an Engineering Justification Paper has been judged as Partially Justified overall, there may be elements of activity (different asset categories/ cost areas) within the paper that have been judged as justified.

Ofgem's responses, to some of our supplementary questions, have identified that there are instances where an Engineering Justification Paper has been judged overall as Partially Justified with some elements of activity justified, but the submitted volumes for the justified elements of activity have not been allowed in the modelled volumes (instead modelled volumes have been determined using the technical assessment that is applied for partial justification).

Where individual elements within a Partially Justified Engineering Justification Paper are identified as justified, this must be recognised and volumes determined from WPD's submitted volumes for the appropriate elements.

Separate feedback from the Engineering Justification Paper review on the view of justification formed for each asset category/ cost area covered by an individual Engineering Justification would provide the clarity required to demonstrate that each element of activity has been correctly treated within the volume assessment. We have requested this visibility through the supplementary questions that we have submitted following publication of Draft Determinations, but the responses provided are generic and do not provide adequate clarity on the assessment of sub-elements.

Rejection of Asset Replacement EJPs

A small number of the Engineering Justification Papers submitted for Asset Replacement activities have been found to be unjustified by the Ofgem Engineering Review. This includes proposed volumes of replacement for 132kV Transformers and EHV Transformers.

Where this has occurred, zero allowance has been provided in the modelled volumes.

We note that whilst these EJPs have been rejected, it was found that we had provided sufficient justification for the investment's needs case. It appears that the concerns related more to the justification for the proposed level of activity, rather than determining that no activity is required.

Given that the need for investment has been sufficiently justified, it seems wholly inappropriate for zero volume allowance to be determined. Instead modelled volumes should reflect a view of reasonable investment need, to ensure that the safety and resilience of the network is not being compromised.

We believe that, in such circumstances, it would be more appropriate to regard these EJPs as partially justified, rather than simply rejecting them in entirety.

We recognise that it can be argued that zero allowance for an activity in disaggregated benchmarking does not mean that no allowance is provided in the overall cost assessment. The reasoning behind such a view is that a portion of the allowance determined by Totex benchmarking could, arguably, be considered to apply to the specific activity that was given no allowance in disaggregated benchmarking. Such a view, however, fails to recognise that each of the benchmark models fundamentally must produce a view of reasonable allowances for RIIO-ED2, in order to be suitable in setting overall allowances.

Additional EJP Information Submission

We have provided supplementary EJP addendums for all EJPs that have been assessed as being either partially justified or unjustified. For EHV transformers, 132kV transformers and 132kV Towers these addendums are further supported by site specific data.

Unit Cost Assessment

We have concerns that determination of benchmark unit costs, and some of the information used in their derivation, is not sufficiently robust to ensure that the assessed efficient unit costs are representative of the current prices and market rates, and therefore are not deliverable.

Unit cost assessment has been undertaken by consideration of three different unit costs:-

- RIIO-ED1 Actuals (the multi-year actual reported unit cost for the six year period 2015/16 to 2020/21);
- All Forecasts (the multi-year unit cost for the seven year period spanning the remaining two years of RIIO-ED1 (i.e. 2021/22 and 2022/23) and RIIO-ED2. This is derived from submitted expenditure and activity forecasts);
- RIIO-ED1 Expert View (Ofgem's benchmark unit cost as used in 2014 for cost assessment of DNO's RIIO-ED1 business plans).

Use of normalised cost data

The RIIO-ED1 Actuals and All Forecasts unit costs are the Industry Median unit costs determined from normalised DNO cost data.

We note that where DNOs have company specific factor adjustments to their Asset Replacement costs, these adjustments are spread across all asset categories to create the normalised cost data used to determine the DNO's own unit costs for each asset category.

Some of the company specific factors relate to the Asset Replacement of specific asset types only (for example, the case for the Asset Replacement company specific factors applied to SP Manweb were presented separately for each asset type) . By spreading such adjustments across other asset categories this incorrectly lowers the unit cost in these other asset categories, potentially skewing the Industry Median and the outcome of any variance assessments.

Where company specific factors relate to specific asset types, the normalisation adjustment needs to be applied to the relevant asset type, and not spread across other unrelated assets, for the purposes of determining the unit costs for Asset Replacement.

Similarly, some of the company specific factors relate to higher volumes of Asset Replacement activity driving increased Asset Replacement expenditure. These are not company specific factors that relate to additional cost for delivery of a unit of work.

Ofgem's current process removes the costs associated with these higher volumes, but does not remove the associated volumes.

By including such adjustments within the cost normalisations used to determine the unit costs for Asset Replacement benchmarking, the unit cost of delivery is not being determined correctly, because the corresponding reduction in volumes is not being considered within the unit cost.

Where company specific factors relate to increased volumes of activity, either:-

- the normalisation adjustment should not be applied to the costs used determining the Asset Replacement unit costs; or
- a corresponding normalisation adjustment to the volumes should be applied when determining the unit cost.

<u>Use of the coefficient of variance to determine acceptability of the RIIO-ED1 Actuals and All Forecasts unit costs</u>

In determining unit costs, Ofgem has made use of a blend of the three separately assessed unit costs (i.e. RIIO-ED1 Actuals Industry Median unit cost, All Forecasts Industry Median unit cost and RIIO-ED1 Expert View unit cost).

The variance between the RIIO-ED1 Actuals and All Forecasts Industry Median unit costs and the individual data used in their derivation has been assessed to determine whether the data should be used. Where the coefficient of variance is outside of a defined threshold limit, the individual unit cost is rejected and not used in the blended unit cost unless accepted using a manual 'acceptability override'.

Our examination of this coefficient of variance assessment shows that valid Industry Median costs are being rejected from inclusion in the blended unit cost as a result of one or two clear outlier unit costs.

A more subjective assessment of the acceptability of the RIIO-ED1 Actuals and All Forecasts Industry Median unit costs is required that considers the impact of outliers, so that valid median unit costs are not being incorrectly rejected as a result of small numbers of clear outlier unit costs amongst the DNO data.

We suggest that, where outlier unit costs are impacting the acceptability of the RIIO-ED1 Actuals and All Forecasts Industry Median unit costs, these could be addressed by either:-

- removal of the outlier unit cost from the data set used in the unit cost assessment; or
- retaining the outlier unit cost but applying the manual 'acceptability override'.

The approach selected may need to be different on a case by case basis taking account of the impact of the outlier(s) on the resulting Industry Median values.

<u>Consideration of outlier unit costs</u>

Outlier unit costs may occur for reasons such as:-

- the phasing of expenditure on multi-year projects that span beyond the period under consideration for the unit cost;
- projects with work content significantly different from the standard scope of works (particularly for asset categories where low volumes of activity are undertaken);
- issues such as the treatment of normalisations when calculating unit costs (discussed above).

Such outliers should be individually examined and, where necessary, excluded from the values used to determine the benchmark unit cost, so that they do not skew the Industry Median or the outcome of any variance assessments.

Where it is identified that for a particular DNO, there is a particular asset category whose unit cost represents a significantly different work content to the standard expected scope of works, it is suggested that the unit cost applied in determining modelled costs is assessed using qualitative analysis.

We have identified one such case in our supplementary question WPD006 (submitted 8th July 2022). This provided detail of the increased scope of works relating to 132kV circuit breaker replacement at Rugeley 132kV substation in WMID (which was reviewed as part of the Engineering Justification Paper Review and found to be justified). These works include high volumes of consequential cable assets. We request that Ofgem apply a DNO specific unit cost within the Asset replacement modelled costs for WMID under Final Determinations that recognises the increased scope of works in this particular case.

<u>Inclusion of RIIO-ED1 Expert View within the blended unit cost</u>

Rejection of one of, or both, the RIIO-ED1 Actuals Industry Median and/or All Forecasts Industry Median unit cost through assessment of a coefficient of variance leads to a blended unit cost that is often dominated by the Ofgem RIIO-ED1 Expert View unit cost.

The RIIO-ED1 Expert View is not subjected to any suitability assessment and therefore is always accepted in creating the blended unit cost. As the suitability of the RIIO-ED1 Expert View is not being assessed against any recent historical or forecast cost data, there can be no confidence that it reflects the cost of activities that will be undertaken in RIIO-ED2.

The RIIO-ED1 Expert View unit costs were derived as part of the cost assessment of DNO's RIIO-ED1 business plans in 2013 and 2014. These were based on Ofgem's forecast view of the likely efficient unit cost for RIIO-ED1. These unit costs were derived from consideration of the DPCR5 historic actual and forecast unit costs and/or the DNO forecasts for RIIO-ED1. This means that in many cases the data used to derive the RIIO-ED1 Expert View could include consideration of costs incurred 12 years ago at the start of DPCR5.

While, the Expert View unit costs from RIIO-ED1 have been indexed to 20/21 prices, no account has been taken of any real price effects, changes in standards or practices, since 2014. This not only makes the RIIO-ED1 Expert View unsuitable for use as a forecast for the efficient unit costs that will be achievable in RIIO-ED2, it also does not reflect the actual costs that the industry incurred during RIIO-ED1.
For these reasons, the RIIO-ED1 Expert View unit cost <u>should not be used</u> in the unit cost assessment of Asset Replacement for RIIO-ED2, other than as a yardstick to sense check the RIIO-ED1 Actuals Industry Median unit cost.

<u>Selection of an appropriate benchmark unit cost</u>

The blended unit cost used in the draft determinations applies an equal weighting to the RIIO-ED1 Actuals Industry Median unit cost (if not rejected by the variance analysis), the All Forecasts Industry Median unit cost (if not rejected) and the RIIO-ED1 Expert View unit cost.

This approach produces a blended unit cost that is weighted heavily towards consideration of RIIO-ED1 costs (both forecast and actual) and not towards forward looking RIIO-ED2 costs. This means that the weighted unit costs will fail to adequately take into account changes in market prices and rates that will affect RIIO-ED2 costs. An example of this is the Ecodesign requirements for transformer energy-related products specified under EU Directive 2009/125/EC. This has impacted the specification of the transformers that may be offered by manufacturers from 2021 onwards, which has resulted in price increases that are not reflected in the RIIO-ED1 Actuals unit costs or the RIIO-ED1 Expert View unit cost.

We have already outlined our reasoning for removing consideration of the RIIO-ED1 Expert View unit cost from inclusion in the blended unit cost, due to its validity as a suitable benchmark cost. This would also reduce the emphasis on RIIO-ED1 unit costs in the blended unit cost.

We have also explained that the appropriate treatment of outlier DNO unit costs within the derivation and assessment of the RIIO-ED1 Actuals and All Forecasts Industry Median unit costs would improve the acceptability of these unit costs for benchmarking.

We believe that benchmark unit costs for the assessment of Asset Replacement should either:-

- be based upon industry median RIIO-ED2 forecast unit costs, or an All Forecasts industry median, with RIIO-ED1 Actuals and the RIIO-ED1 Expert View used as yardsticks (for cross checking only). Where the benchmark unit costs deviate materially from the RIIO-ED1 yardsticks, Ofgem should subject these to a separate expert review and determine a qualitative view of an appropriate unit cost; or
- if a more mechanistic approach using a blended unit cost is required, be determined by combining both the RIIO-ED1 Actuals and All Forecasts Industry Median unit costs with equal weighting to produce a view of the efficient unit costs for Asset Replacement that:-
    - takes account of historic efficient delivery through the RIIO-ED1 Actuals Industry Median; but
    - balances historic performance with the forwards looking view of cost provided by the All Forecasts Industry Median.

These approaches provide a more suitable basis for the modelled unit costs applied in the assessment of Asset Replacement.

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

The assessment of refurbishment has been undertaken with separate activity volume assessment and unit cost assessment.

The scope of works that can be considered as Refurbishment (NARM) and Refurbishment (non NARM), and definition of asset categorisations, are sufficiently defined within Ofgem's BPDT guidance to ensure a suitable degree of consistency in the reporting of Refurbishment expenditure and activity by DNOs, to facilitate separate benchmarking of activity volumes and unit costs.

We agree with the general principle of assessment of Refurbishment through separate volume and unit cost assessment. However, we have concerns about some aspects of the way this has been undertaken for Draft Determinations.

Volume Assessment

As with Asset Replacement, volume assessment has been performed using both quantitative and qualitative analysis.

We are in agreement with the use of a tool-kit approach that considers a range of qualitative and quantitative evidence.

Where a relevant Engineering Justification Paper has been submitted, and the Engineering Justification Paper provides sufficient justification, it is appropriate that the submitted activity volumes are allowed as the modelled volumes.

We also agree that where:-

- submitted activity volumes have been judged as Partially Justified through the Engineering Justification Paper review; or
- the submitted activity is not covered by an Engineering Justification Paper;

it is appropriate for modelled volumes to be based on technical assessment that considers both the volumes determined from quantitative analysis as well as other additional supporting evidence. However, it is not clear as to how some of the supporting evidence provided as part of Business Plan submissions, such as NARM data, has been incorporated into such assessments.

The quantitative analysis undertaken comprises run-rate analysis and age-based modelling.

We do not believe that the age based survivor model results are applicable to Refurbishment activity. The survivor model volumes considered in the assessment of Refurbishment volumes are the same as those used in the analysis of Asset Replacement. This modelling technique is used to provide an indication of likely future asset replacement volumes, based on a probabilistic assessment of an asset 'surviving' each future year of its life. This type of analysis is not applicable to Refurbishment.

Refurbishment activities are undertaken either to address major defects or are proactive interventions to extend an assets life (e.g. routine tower painting) and the concept of 'surviving the year' is not valid. In fact, many of these Refurbishment activities may be undertaken at any point during an assets life and therefore are not triggered by the age of the asset itself.

Unit Cost Assessment

We have concerns that the approach taken to determining benchmark unit costs has not given sufficient recognition to the range of activities (and therefore costs) that can be considered as Refurbishment for each individual asset category.

Unit cost assessment has been undertaken by consideration of three different unit costs:-

- Industry Median RIIO-ED1 Actuals unit cost (the multi-year actual reported unit cost for the six year period 2015/16 to 2020/21);
- Industry Median All Forecasts unit cost (the multi-year unit cost for the seven year period spanning the remaining two years of RIIO-ED1 (i.e. 2021/22 and 2022/23) and RIIO-ED2. This is derived from submitted expenditure and activity forecasts); and

- a notional Ratio unit cost derived by determining a benchmark ratio of the unit cost of refurbishment to unit cost of asset replacement (using a combination of both RIIO-ED1 and RIIO-ED2 periods), which then is applied to the Asset Replacement expert view unit cost.

<u>Use of the coefficient of variance to determine acceptability of the RIIO-ED1 Actuals and All Forecasts unit costs</u>

In determining unit costs for RIIO-ED2, a blend of the three separately assessed unit costs has been used.

For the derivation of the RIIO-ED1 Actuals and All Forecasts unit costs, the variance between the industry median and the individual DNO data is assessed to determine whether the unit cost is accepted or rejected. Where the coefficient of variance is outside of a defined threshold limit, the individual unit cost is rejected and not used in the blended unit cost unless accepted using an acceptability override is manually applied.

The Refurbishment and Repairs & Maintenance Task Allocation Tables in the RIIO-ED2 Business Plan Data Template – Glossary identify the various work activities that can be considered as Refurbishment (NARM) and Refurbishment (non NARM) for each asset category. For a given asset type, there are considerable differences in the cost of delivery for some of the various work activities that are classified as Refurbishment. For example, the replacement of gaskets and seals on a 33kV Transformer (GM) asset is classified as a Refurbishment (NARM) activity but would be expected to be delivered at a significantly lower cost than some of the other Refurbishment (NARM) activities such as replacement of a tapchanger or replacement of windings.

The overall unit costs for each DNO will reflect the different mix of the individual work activities that are undertaken within each DNO. This can result in a significant range of unit costs between DNOs in the assessment of the Industry Median RIIO-ED1 Actuals and Industry Median All Forecasts unit costs. In many cases this range in unit cost, due to differences in mix of activity, causes the benchmark unit costs to be rejected by the variance analysis (because the coefficient of variance is outside of the defined acceptable range).

Within the unit cost assessment performed for Draft Determinations, we note that the acceptability override has only been used on one occasion in the assessment of 'Refurbishment non NARM' and 'Refurbishment NARM' benchmark unit costs.

As a result of the application of the variance assessment and the very limited usage of the acceptability override, valid median unit costs reflecting the cost of delivery observed across RIIO-ED1 and the anticipated unit costs of activity in RIIO-ED2 are being disregarded in the derivation of the benchmark unit costs.

For both 'Refurbishment non NARM' and 'Refurbishment NARM', we would encourage Ofgem, for all asset categories, to:-

- undertake additional examination of the Industry Median RIIO-ED1 Actuals and Industry Median All Forecasts unit costs that are rejected due to the variance assessment;
- consider broadening the acceptance limits for the coefficient of variation; and
- make greater use of the acceptability override;

because, for most asset categories, the range of activities that are classified as Refurbishment can vary significantly in cost and therefore a high degree of variability in unit cost across DNOs would be expected to be observed.

Calculation of the Ratio Unit Cost

The Ratio unit cost is derived by determining a benchmark ratio of the unit cost of refurbishment to unit cost of asset replacement (using a combination of both RIIO-ED1 and RIIO-ED2 periods), which then is applied to the expert view unit cost that has been determined for the assessment of Asset Replacement expenditure.

This approach creates a proxy unit cost on the assumption that there is a constant cost relationship between Refurbishment activity and Asset Replacement activity on each asset category.

There are a number of asset categories where a Ratio unit cost of £0k has been determined in Draft Determination, yet modelled volumes of activity have been determined. These cases need to be examined and corrected in Final Determinations, as providing a unit cost of £0k for activities that actually incur cost is illogical and unacceptable.

Core-Q75. Do you agree with our proposed assessment approach for asset replacement driven civil works?

We agree with the proposed use of ratio benchmarking for the assessment of Civil Works Driven By Asset Replacement.

However, there is an issue with the ratio chosen in the consultation. It is not appropriate for benchmarking of these costs. This is because:-

- the proposed use of the ratio of total asset replacement driven civil works to total asset replacement costs fails to recognise that not all Asset Replacement activities drive expenditure on Civil Works Driven By Asset Replacement; and
- the use of a single ratio to benchmark overall Civil Works Driven By Asset Replacement does not recognise the significant differences in civil work content associated with asset replacement at different voltage levels (and the relativity to the associated plant costs).

Use of the correct asset replacement activities that drive civils costs

Civil Works Driven By Asset Replacement is defined in the RIIO-ED2 Business Plan Data Template – Glossary as "Civil works undertaken to replace or modify existing civils items primarily required to facilitate, or enable, Asset Replacement of plant assets". As these civil works costs relate only to civil works associated with the replacement of plant, only the Asset Replacement costs for the associated plant replacement should be considered in the ratio benchmarking.

The approach used in the draft determination includes the replacement of plant, but also incorrectly includes the total Asset Replacement costs of activities that do not drive Civil Works Driven By Asset Replacement expenditure, such as the replacement of overhead lines, underground cables, services and cut-outs.

These other asset replacement activities account for a significant proportion of Asset Replacement costs and therefore their inclusion in the derivation of the ratio used for

assessment of Civil Works Driven By Asset Replacement incorrectly distorts the benchmarking outcomes, especially where dissimilar proportions of these other replacement activities are undertaken across DNOs. Similarly asset replacement of pole mounted plant will not incur any Civil Works Driven By Asset Replacement expenditure as the support structures (i.e. poles) are separate Asset Replacement asset categories in their own right. For this reason, the asset replacement costs of pole mounted plant assets should also be excluded from the Asset replacement costs used to derive the benchmark ratios. Ratio benchmarking of Civil Works Driven By Asset Replacement must be undertaken by consideration of only those Asset Replacement costs relating to the relevant plant assets that drive Civil Works Driven By Asset Replacement expenditure. <u>Disaggregation of activities in cost benchmarking</u> It is noted that benchmarking has been undertaken at an overall total cost level for Civil Works Driven By Asset Replacement. The use of this single benchmark ratio applied to the assessment of all Civil Works Driven By Asset Replacement modelled costs is a simplification that does not take into account the differences in civil work content associated with the replacement of assets at different voltages. We understand from paragraph 7.237 of the Core Methodology Document that Ofgem tested benchmarking "at a more disaggregated level by voltage but found the cost ratio to be more variable between DNOs' and over time". We believe that such variability will be reduced where disaggregated benchmarking of Civil Works Driven By Asset Replacement costs is undertaken using the ratio of asset replacement driven civil works to only the relevant plant asset replacement costs (as detailed above). Without using suitable disaggregated benchmarking, the modelled cost for Civil Works Driven By Asset Replacement will not be representative of the civil works associated with the mix of Asset Replacement activities within each DNO. In particular, disaggregated ratio benchmarking should consider, not just different voltage levels, but also differences in civil works associated with the replacement of HV assets at primary substations, compared to secondary substations. The data provided within the Business Plan Data Templates facilitates disaggregation across six categories and we suggest that this is the most appropriate level of assessment to use. We have provided more details on how to apply the benchmarking in our supplementary question WPD033 CV7c Civil Works Driven by Asset Replacement – Ratio Benchmarking.
Core-Q76. Do you agree with our proposed assessment approach for Condition Based Civil Works?
We note that the assessment of Condition Based Civil Works has been undertaken using separate volume and unit cost assessment, where: • volumes have been assessed (at a disaggregated level by site type) using the industry median benchmark ratio of annual average civil works activity volumes to the total population of sites in the Asset Register tables; and

- unit cost assessment has been undertaken using the industry median unit cost calculated for a unit of civil works activity volumes at each site type.

We agree that it is appropriate to benchmark Condition Based Civil Works by consideration of the levels of expenditure proportionate to the overall number of sites operated by the DNO.

However, the separate assessment of volumes and unit costs that has been undertaken assumes there is sufficient uniformity in a unit of average civil works activity for separate volume and unit cost assessment to be undertaken. Such uniformity does not exist to support this approach, therefore separate volume and unit costs assessments should not be carried out.

The Refurbishment and Repairs & Maintenance Task Allocation Tables in the RIIO-ED2 Business Plan Data Template – Glossary identify the various civil works activities that can be considered as Repairs & Maintenance and those that are considered under Condition Based Civil Works. The range of activities that can be considered as Condition Based Civil Works ranges significantly in scope and cost, between activities such as replacement of a single door, window or heater panel, through to full replacement of a roof or entire buildings. This range in scope of works means there is not sufficient uniformity in a unit of work for unit cost assessment to be appropriate.

Furthermore, under the Business Plan Guidance for CV10, the unit of activity that is reported under Condition Based Civil Works is "the number of unique substations where civil works have taken place during the reporting year". This means that the number of units of activity shown for a DNO during a price control period will vary depending upon how the DNO approaches management of each site. For example, if a DNO replaces five windows at a single site during a single five year price control period a total unit count of five would be reported if the DNO visited the site each year and only replaced one window each time. However a total unit count of one would be reported if the DNO only visited the site in a single year and replaced all of the windows in the same year. This issue around reporting of a unit of work introduces further inconsistency in the units of work, making the unit unsuitable for benchmarking purposes.

In principle, there is a significant risk that, because of the lack of consistency in the unit of activity, the benchmark volume and the benchmark unit cost are not consistent with each other and where combined will produce unrealistic benchmarks for overall modelled cost.

This issue with the consistency of the unit of work can simply be avoided if more generic ratio benchmarking is used. This can be achieved by benchmarking the ratio of the cost of Condition Based Civil Works to the total population of sites in the Asset Register tables (using disaggregated analysis by site type).

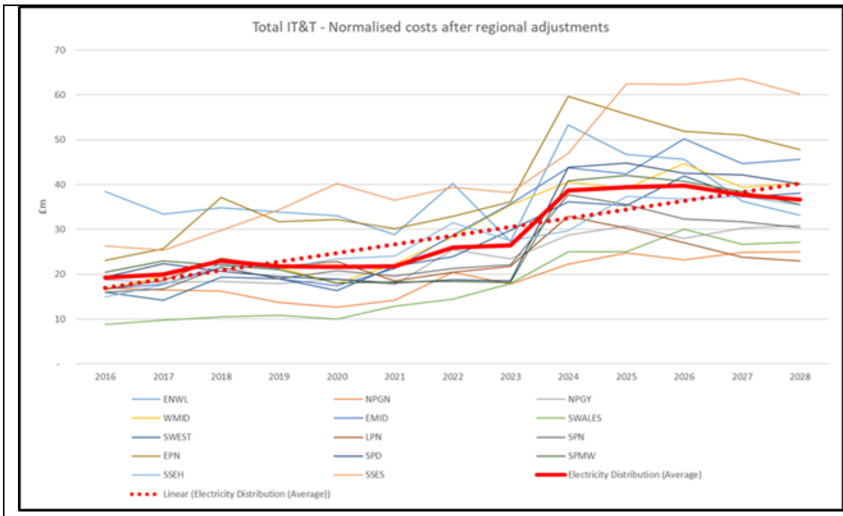
Core-Q77. Do you agree with our proposed assessment approach for diversions?

We acknowledge that Ofgem has accepted DNO forecast volumes.

Volumes of each of the diversions activities will differ across DNOs reflective of the volumes of claims driven by compensation agents, requirements of local landowners and levels of developer activity. For these reasons, it would be inappropriate to compare and benchmark activity volumes.

Ofgem has benchmarked unit costs for Diversions against industry median. WPD's forecast for all activities in Diversions utilised actual ED1 unit costs. We have noticed a significant difference in unit costs across our licence areas, particularly in relation to Developer claims at 132kV, with claims settlements generally more expensive in WPD East Midlands and WPD South West. The unit costs of activities will also be influenced by the same factors that drive activity volumes. DNO policy will, for example, determine the use of wayleaves or easements to settle claims. This is evidenced by the range of unit costs that DNOs are reporting for the different activities. WPD has adopted a pro-active approach to the settlement of diversions claims by reviewing available options for resolution. Costs for equipment relocation are compared to negotiation and settlement costs for the rights to retain equipment in situ, and the most cost effective solution is adopted. The feedback from Ofgem's review of EJP016 Diversions - Conversion of Wayleaves to Easements, Easements and Injurious Affection Claims recognised that 'WPD presented sufficient evidence that the proposed strategy is effective'. If Ofgem accept volumes of activity as forecast by DNOs, then DNO specific unit costs should also be accepted. **Diversions Uncertainty Mechanism** Several other DNOs are proposing the introduction of UM for Diversions and Wayleaves in RIIO-ED2. WPD's approach has always been that we think this activity is best funded ex-ante (as in previous price controls). We have a clear internal strategy for managing these claims and are not convinced that the regulatory complexity of an additional UM would assist in managing this. We therefore do not support the development of a UM.
Core-Q78. Do you agree with our proposed approach for Rail Diversions?
We agree with the proposed approach for Rail Diversions.
Core-Q79. Do you agree with our proposed approach to assessing Non-Operational, Operational and Business Support IT&T costs?
We agree with the approach of assessing these 3 areas of IT&T together. This helps avoid boundary issues in reporting and opex/capex trade-offs. However we raise the following points with regards to areas of the assessment approach. Use of 13 year average is not appropriate All DNOs face step change in their IT&T expenditure in the closing years of RIIO-ED1 and into RIIO-ED2, reflecting a range of challenges including DSO, increase in LV monitoring and Data and digitalisation. This step change is clearly shown in the following graph, which uses data from the DNO BPDTs[19]:

[19] BPDTs shared amongst DNOs, July 2022



However, despite the clear step change, a 13 year median has been used in the benchmarking approach. This means that all DNOs see a reduction in their ED2 IT&T allowances, despite the use of median, as shown in the table below[20]. This causes a very real risk of DNOs being unable to deliver the industry changes that are required for more open data and more sophisticated network operation.

Total IT&T adjustment		
		RIIO-2 Total
ENWL	Cost adjustments	(54.2)
NPGN	Cost adjustments	(20.8)
NPGY	Cost adjustments	(2.1)
WMID	Cost adjustments	(45.1)
EMID	Cost adjustments	(41.7)
SWALES	Cost adjustments	(56.1)
SWEST	Cost adjustments	(78.6)
LPN	Cost adjustments	(20.3)
SPN	Cost adjustments	(26.8)
EPN	Cost adjustments	(36.0)
SPD	Cost adjustments	(77.7)
SPMW	Cost adjustments	(71.2)
SSEH	Cost adjustments	(83.4)
SSES	Cost adjustments	(74.2)
		(688.4)

We recommend, as a minimum, a shortened average using RIIO_ED2 data only (or from 2020/21 at the earliest) is more appropriate, given it better reflects future IT&T investment needs.

Selection of cost driver

Our responses to Q64 (totex benchmarking) and Q102 (CAI) outline in detail our concerns with MEAV as a flawed measurement of DNOs' scale and a proposal to place less weight on MEAV and instead a higher weight on more relevant and objective measures of scale such as network length and customers. We suggest the same proposals are adopted for most disaggregated models where MEAV is currently the core driver used.

Quantitative vs qualitative approach

The RIIO-ED1 approach accounted for both quantitative and qualitative assessment (capex: 25% quantitative and 75% qualitative; opex 50%/50%). The RIIO-ED1 Slow Track Final Determinations recognised "the significant increase in IT&T costs and the various reasons…..led us to give more weight to the qualitative assessment…",

[20] From cost assessment file "ED2Models_MasterTemplate_Disagg_IT&T"

acknowledging the limitations in the quantitative assessment and "the justifiable differences between individual DNOs IT strategies"[21]. These arguments are even more valid for RIIO-ED2 – there is a further significant increase in IT&T costs from RIIO-ED1 and RIIO-ED2, and DNO IT strategies will still be different. However, the RIIO-ED2 approach uses qualitative review as an input only. It is argued in Draft Determinations that this makes it more robust and enriches the assessment – but the RIIO-ED2 approach doesn't make any adjustments other than downward adjustments. Therefore all investment is subject to benchmarking, even if a strong needs case is provided. We believe this is a weaker approach in RIIO-ED2 and that a richer and more rounded qualitative review and assessment is undertaken to sit alongside quantitative assessment, as it did in RIIO-ED1. We agree with the proposal to not make any adjustments to costs related to data and digitalisation and are pleased that Ofgem has recognised the importance of the delivery of this agenda. However, there is still a risk that important investment is removed though quantitative benchmarking. A qualitative approach which sits alongside quantitative approaches would reduce this risk. <u>Treatment and testing of DSO in modelling</u> We note Ofgem's proposal for baseline funding for DSO activities in paragraph 4.47 of the Core Methodology document and that strategy proposals have been allowed except where justifications have been judged as weak in accompanying EJPs. Ofgem also state that they "are also mindful that many of these investments lack a historical equivalent or comparator in RIIO-ED1." However, there is no further discussion of DSO in the cost assessment approach in Chapter 7 of the Core Methodology document. From the response to SQ WPD027, we understand that the M19 memo table of the BPDTs was used for a qualitative assessment of the DSO proposals and that, unless stated otherwise, all DSO costs were included in the baseline costs, subject to Ofgem's cost assessment, in recognition of the acceptance of the strategy proposals. It would be useful if more detail could be shared on the qualitative assessment approach that has been undertaken, and how differences in DNO submissions in table M19 have been considered. We also reiterate, similar to the paragraph above on digitalisation, that the current approach still includes the risk that important investment is removed through the quantitative approach. We note that cyber security costs have been excluded from totex modelling, because of a significant change in the equivalent level of costs between RIIO-ED1 and ED2. This is also a criteria which applies to DSO investment and has been recognised by Ofgem themselves in para 4.47 of the Core Methodology, as referenced above. We therefore think there is rationale for excluding these costs from totex assessment. There is no rationale for treating the two costs in different ways. <u>Interaction with Telecoms resilience</u> It is important that we are adequately funded and that sufficient allowances are included in the baseline. Please see response to Q59. <u>Interaction with Cyber security</u> This has been separately assessed from the remainder of IT&T cost assessment. Please see responses to Q61-62 and to Cyber Resilience consultation questions, which

[21] Ofgem, RIIO-ED1: Final Determinations for the slow-track electricity distribution companies, Business plan expenditure assessment (28 November 2014), ch 8

address WPD concerns on the scale and operation of UMs proposed for cyber security in RIIO-ED2 Draft Determinations. Key points that are reiterated here in this question response are: • 17% (associated with 'optimism bias') has been incorrectly removed from the IT and OT Cyber Year 1 allowances and it has been agreed with the Ofgem cyber term that these should be reinstated (see SQ WPD WPD063) • We disagree with Ofgem's proposal to only approve year one funding at this point. Providing only one year of funding poses a number of commercial, cyber security and operational risks on WPD. Therefore, the provision of ED2 year two funding is essential for the sustainability of risk reduction and for the success of the programme (see Cyber Resilience consultation question responses). Regarding cyber exclusions in totex modelling, consideration should be taken of the RIIO-ED1 expenditure when calculating exclusions for totex modelling because there is inconsistency in reporting: 4 DNOs have reported costs from 2020 onwards only (when the requirement to separately identify cyber cost was established); only 2 DNOs have restated back to 2016. This reporting issue needs to be resolved (see Q63)
Core-Q80. Do you agree with our proposed assessment approach for Legal and Safety?
We agree with Ofgem's approach to assessing Legal and Safety expenditure.
Core-Q81. Do you agree with our approach to assessing Overhead Line Clearance costs?
We agree with Ofgem's approach to assessing Overhead Line Clearance.
Core-Q82. Do you agree with our proposed approach to assessing ESR costs?
We agree with the proposal to utilise an uncertainty mechanism to provide allowances once industry ESR requirements are determined.
Core-Q83. Do you agree with our proposed approach to assessing QoS and NoSR costs?
No. There is an intrinsic link between expecting network performance improvements and network investment to achieve those improvements. We provide detailed responses to Q44-Q49 and these should be read in conjunction with this response. Since Ofgem's current proposals is to base IIS targets on DNO's own performance, set further improvement requirements and provide no funding, we believe that the IIS mechanism will lead to penalties if no further improvements to network performance are made. Given that Ofgem recognises that there are diminishing opportunities to make improvements, investment will be required to remain neutral on the IIS (i.e. have no penalty or reward). Since there are expectations from Ofgem and stakeholders that performance should improve, such improvement needs to be funded through allowances.

It would be reasonable to have allowances that allow DNOs to stay neutral on IIS. Beyond this, DNOs can utilise the incentive opportunity provided by the IIS to provide further enhancements to service, where there is a cost benefit of doing so. For WPD, the proposed investment programme seeks to marginally stay ahead of the proposed draft targets in the Sector Specific Methodology Document. These can be viewed as the investment necessary to stay neutral under IIS. Therefore if there are no changes to the IIS arrangements, allowances should be provided for QoS.
Core-Q84. Do you agree with our proposed assessment approach for Physical Security?
We agree with the proposal to utilise an uncertainty mechanism to provide allowances should enhance security arrangements be identified.
Core-Q85. Do you agree with our proposed assessment approach for Flood Mitigation?
No. We are surprised and disappointed that Ofgem's assessment of the requirements for flood defences leads to no volumes of activity being proposed. This outcome is contrary to the greater focus being placed on ensuring that networks are resilient to severe weather situations. Ofgem propose to disallow all forecast volumes for WPD's Flood Mitigation proposals following review of EJP041. The Engineering Review feedback for EJP041 states the following: *"<u>WPD provide sufficient needs case for the work</u>. However, the optioneering discussed within the EJP is insufficient. The EJP does not provide enough explanation for the three different proposed options (80, 95 or 102 sites) and how these were derived. <u>Optioneering seems reliant on enhanced stakeholder engagement, but this isn't expanded upon in any detail</u>. Due to the insufficient optioneering, there is a risk that the most efficient solution for these works has not been presented within the EJP."* We note that Ofgem has assessed that there is a sufficient needs case for the work. The volumes of flood defences were one of a number of subjects that underwent extensive stakeholder engagement. The EJP only provided a brief summary of the results because further details regarding how our Core Commitments were developed and agreed with our Stakeholders are contained within WPD RIIO-ED2 Supplementary Annex 5 – Giving customers a stronger voice: Enhanced Engagement. This document outlines the various stages of stakeholder engagement and how different options, including those for Flood Protection volumes, were tested, challenged and supported by Stakeholders. An overview of the development of proposed flood mitigation volumes and the impact of Stakeholder Engagement was provided in SQ WPD012.

Given that Ofgem have assessed that there is sufficient needs case for the flood mitigation programme, we cannot accept the total removal of all forecast flood protection volumes from allowances. We have provided additional information on flood defences in and EJP041 Addendum document. <u>Cost Benchmarking</u> Aside from the impact of the EJP review excluding all volumes, Ofgem's approach to unit cost benchmarking and volume benchmarking of Flood Mitigation programmes appears to be appropriate.
Core-Q86. Do you agree with the proposed approach to assessing Rising and Lateral Mains costs?
No. We are surprised and disappointed that zero allowances are provided under disaggregated costs assessment. The approach being adopted by WPD is different to that being adopted by some other DNOs. WPD is seeking to work with building owners to identify the ownership of rising and lateral mains. Once ownership is established, there will be clear responsibility for the ownership and associated costs for WPD. The process of identifying ownership is in progress and as a result our cost forecasts are estimated based upon a small percentage of buildings requiring WPD to carry out work. We believe that this is a pragmatic approach and while we do not have certainty about which buildings will require work, we have proposed a small amount of costs that are to be utilised for ensuring that customers continue to have power supplies while ownership is resolved. We note that the assessment by Ofgem's Engineering Hub rejects our proposals and therefore no allowances are provided. We have therefore provided additional information in EJP070 Addendum to Ofgem to explain our pragmatic approach and illustrate that the proposed costs are very small in comparison to the potential scale of investment requirements. We urge Ofgem to review the additional materials and provide sufficient allowances so that we can upgrade rising and lateral mains that are in poor condition to maintain reliability of supply and safety in high rise buildings and blocks of flats.
Core-Q87. Do you agree with our approach to assessing WSCs?
Paragraph 6.121 states that Ofgem is satisfied that DNOs have an appropriate methodology for identifying and costing projects for improving service for WSC. However under the EJP review by the Engineering Hub, Ofgem has assessed the EJP as unjustified. We note that the volumes provided under the disaggregated analysis are in line with WPD's proposed investments and therefore we assume that the Engineering Hub assessment (which has rejected WPD's proposals) has not been used.

We have, however, provided an addendum to EJP038 to address the concerns raised by the Engineering Hub.
Core-Q88. Do you agree with our proposed assessment approach for Losses?
We broadly agree with the proposed cost assessment approach, but disagree with the use of RIIO-ED2 expert view asset replacement unit costs. **Unit Costs** As detailed with the response to Q73 for asset replacement benchmarking the RIIO-ED2 expert view is simply an inflated value of an assessment carried out in RIIO-ED1. These unit costs were derived from consideration of the DPCR5 historic actual and forecast unit costs and/or the DNO forecasts for RIIO-ED1. This means that in many cases the data used to derive the RIIO-ED1 Expert View could include consideration of costs incurred 12 years ago at the start of DPCR5. It is more appropriate to use the unit costs that result from the blending of different analysis and are used for asset replacement, rather than solely relying on this expert view that does not reflect incurred or forecast costs. **Reputational Measure** We agree that it is appropriate to include Losses as a reputational measure within the Environmental Reporting Pack. **Rejection of WPD volumes.** We are disappointed that Ofgem has rejected WPD's proposals to reduce losses by removing higher loss transformers from the network, through which we will also be providing more capacity on the network. Regarding Ofgem's specific comments about WPD's proposal for installation of lower loss transformers in paragraph 7.307, we provide an addendum to EJP193 to add more detail to our proposal.
Core-Q89. Do you agree with our proposed assessment approach for environmental reporting?
WPD agree that the RIIO-ED1 assessment method should be an appropriate approach to use for RIIO-ED2. In relation to the assessment of each cost category we agree with the Proposals for RIIO-ED2 as set out in Table 50 but note the following; Carbon offsetting or removal – '*We propose to disallow WPD, UKPN and SPEN costs on carbon offsetting and SSEN costs on carbon removal, as we consider them to be unjustified. For further information, please see Chapter 3'* Chapter 3 states the following referring to Appendix 1 EAP; '*UKPN, WPD, and SPEN have proposed to spend consumer funds on carbon offsetting to achieve net zero. We request that the DNOs submit further information as part of their respective consultation response*.'

Further information as requested in Appendix 1 – EAP is provided in Core Methodology - Appendix 1 EAP Proposals. It is unclear as to whether the provision of the further information as requested in Appendix 1 will alter the decision on the proposed carbon offsetting or removal costs as detailed in Table 50. WPD has provided additional information on carbon offsetting which we have done in our response in Core Methodology - Appendix 1 EAP Proposals - A1.43 Carbon offsetting or removal.
Core-Q90. Do you agree with our proposed assessment approach for PCBs?
No. We are pleased that Ofgem had accepted DNO forecast PCB volumes without amendment, however we do not agree with the proposed approach to the benchmarking of unit costs for PCBs. Ofgem has created a RIIO-ED1 and RIIO-ED2 PCB baseline unit cost per DNO, which combines all PCB activities. WPD are proposing to complete all oil testing during RIIO-ED1, and have not included any forecasts for this activity during RIIO-ED2. This activity is significantly cheaper than other PCB activities, and therefore lowers the RIIO-ED1 and RIIO-ED2 baseline unit cost when aggregated with more expensive activities. Unit cost benchmarking should be completed for each separate PCB activity, rather than at the aggregated level, the allowed costs will be therefore be more reflective of the forecast activity to be undertaken. Unit costing by individual activity also provides the baseline reference cost for the PCB uncertainty mechanism.
Core-Q91. Do you agree with our proposed assessment approach for Property?
We agree with the approach of assessing Non-operational Property (capex) and Property Management (opex) together. We agree that there should be correlation between these activities and that this is a consistent approach with IT&T and Vehicles & Transport. However opex/capex trade-offs are longer-term in Property compared to these other areas, which needs consideration. With this in mind, we therefore raise the following points with regards to the following areas of the assessment approach. <u>Importance of qualitative assessment</u> Property capital investment is long-term, demonstrated by the life of property assets compared to Vehicles and IT&T for example. The purchase of major sites and major refurbishment works will be ‘lumpy’, long term expenditure and not necessarily comparable in either a 5 year price control or through use of a 13 year average A key example is in the SWEST licence area. Sufficient needs cases have been presented in the submitted EJPs[22] for 3 large property projects (totalling £40m), but no qualitative adjustment has been made, meaning these projects have been benchmarked out.

[22] EJPs 004-006 Exeter, Torquay and Plymouth depot refurbishment

To address this issue, qualitative adjustments need to be made to work both ways: not just negative adjustments where a project is thought to be unjustified, but positive adjustments especially where projects are large, long term in nature and sufficient needs assessed.

Without appropriate qualitative assessment, DNOs will not get the allowances they need in the long term to ensure adequate investment, as well as in the shorter term to ensure we meet health and safety legislation and environmental aspiration. Median benchmarking with downwards only qualitative adjustment is not appropriate for setting allowances in this activity.

We also previously referred to the importance of qualitative assessment in our response to the SSMC[23].

<u>EJPs and Engineering Hub process and assessment</u>
There appear to be a number of cases where DNOs have had reductions applied because of an EJP being provided. Some licensees have subjective assessment with EJPs being rejected, others are only subject to cost modelling.

WPD provided EJPs for all major areas of Property capital investment, which may not be consistent with the submissions from other DNOs. This therefore can cause a consistency/fairness issue across the DNOs, where the only adjustments are negative and no further consideration of the additional evidence to justify the needs case is made in the modelling approach.

We acknowledge the conclusions of the Engineering Hub on the EJPs that have been classified as 'Unjustified' and 'Partially Justified' and EJP addendums are being submitted alongside our consultation response to address these issues.

We draw attention to the following specific EJPs:

- EJP007 General Building Refurbishment Programme

We note Ofgem's feedback on this EJP, and as stated above have provided further supporting information in the form of an addendum to the EJP. However, we are surprised by the outcome of Ofgem's Draft Determinations, which is for an allowance of zero in respect of buildings refurbishment/ capital repairs and maintenance. Notwithstanding that we have supplemented the EJP with the addendum to address Ofgem's feedback in such a way as to reinforce this investment proposal, it is inconceivable that if it is unwilling to accept this EJP, Ofgem can consider a non-operational portfolio of the scale of WPD's to be capable of being maintained over five years for zero spend. We raised this issue in SQ WPD061, and hope we can work with Ofgem to ensure the further information in the addendum is sufficient and that this funding issue will be resolved.

This EJP also includes £6m expenditure on improving energy performance in our buildings, which is a key part of our EAP and CVP1. In Draft Determinations, this CVP has been accepted with no reward, albeit subject to cost assessment.
Another consideration is that if these energy efficiency projects continue to be disallowed, then the additional energy cost in opex should be factored into the modelling (part of the 'do nothing' approach in the EJPs).

The interlinkages between EJP adjustments, business plan outputs and commitments, and implications for different areas of expenditure all need to be considered as part of the cost assessment approach.

[23] WPD response to SSMC, see "01102020 WPD Annex 1 Question Responses to RIIO-ED2 SSMC" pg 66

- EJP008 - Incorporating Solar PV in our Non-Operational Sites

£2m of cost has been disallowed (of £4m total cost) in the disaggregated property model for this EJP. SQ WPD021 has identified that there is an error with regards to this disallowance, which needs correction in Final Determinations. We are also submitting an EJP addendum which provides further detail to amend the 'partially justified' rating.
Also, as above, if the cost is disallowed such that investment is either not delivered or only partially delivered, an opex adjustment will be required to account for increased energy costs.

It should also be noted that this project is another key part of achieving our EAP and CVP1 proposals.

Selection of cost driver
Our responses to Q64 (totex benchmarking) and Q102 (CAI) outline in detail our concerns with MEAV as a flawed measurement of DNOs' scale and a proposal to place less weight on MEAV and instead a higher weight on more relevant and objective measures of scale such as network length and customers. We recommend the same proposals are adopted for most disaggregated models where MEAV is currently the core driver used.

Core-Q92. Do you agree with our proposed assessment approach for STEPM?

We recognise that there has been improvements to the RIGs reporting and definition of this activity through RIIO-ED1. We agree this should have addressed previous reporting inconsistencies and that therefore a movement to ratio benchmarking is sensible on this basis.

However we raise the following points with regards to areas of the assessment approach.

Selection of cost driver
Our responses to Q64 (totex benchmarking) and Q102 (CAI) outline in detail our concerns with MEAV as a flawed measurement of DNOs' scale and a recommendation to place less weight on MEAV and instead a higher weight on more relevant and objective measures of scale such as network length and customers. We suggest the same recommendations are adopted for most disaggregated models where MEAV is currently the core driver used.

Choice of time period and qualitative review
Across the industry, there is an increase in cost from RIIO-ED1 to RIIO-ED2. The Core Methodology does not acknowledge this. If the reasons for this are valid, then it should be explored whether a time period using both RIIO-ED1 and RIIO-ED2 data is appropriate to ensure adequate allowances are modelled. For this reason, a time period using RIIO-ED2 data only may be preferable.

Paragraph 7.330 refers to a "supplementary qualitative review". Further detail on the form this took should be shared, especially in the light of the question of time period above. There may be minimal EJP coverage in this area to aid any qualitative review, because of the smaller scale nature of the expenditure.

Core-Q93. Do you agree with our proposed assessment approach for Vehicles and Transport?

We agree with the approach of assessing the 2 areas of Vehicles and Transport (V&T) together. This helps avoid the issues with differences between different DNO operating strategies. However we raise the following points with regards to areas of the assessment approach.

Selection of cost driver

Our responses to Q64 (totex benchmarking) and Q102 (CAI) outline in detail our concerns with MEAV as a flawed measurement of DNOs' scale and a recommendation to place less weight on MEAV and instead a higher weight on more relevant and objective measures of scale such as network length and customers. We suggest the same recommendations are adopted for most disaggregated models where MEAV is currently the core driver used.

In the V&T disaggregated model, a larger adjustment is the outcome in SWEST and SWALES, than in the 2 WPD Midlands areas, as shown in the following table[24].

	Submitted costs	Modelled costs	Adjustment	
	£m	*£m*	*£m*	*%*
WMID	60	51	- 9	-15%
EMID	67	59	- 9	-13%
SWALES	44	25	- 19	-43%
SWEST	57	35	- 22	-38%
WPD	**228**	**170**	**- 59**	**-26%**

However the policy, purchase and management of the vehicle and transport investment is essentially the same across the 4 licence areas; these are managed centrally, and so a more consistent outcome to benchmarking would be anticipated across the 4 DNOs. This further demonstrates the issues with use of MEAV as a suitable driver.

We acknowledge the limitations of using FTE as a driver for this activity.

Choice of time period

We question whether the use of both RIIO-ED1 and RIIO-ED2 data to calculate an industry median is appropriate. The Draft Determinations acknowledge that there is an increase between the 2 price controls which has been adequately explained (paragraph 7.335 in the Core Methodology observes an "increase in costs has been adequately explained by DNOs' associated plans and proposal papers").

This also contradicts paragraph 7.334 which explains the exclusion of DPCR5 data, and observes that there is a transitional change to EV fleet seen in the RIIO-ED1 period. The evidence (of an increase in RIIO-ED2 from RIIO-ED1) suggest this transition is more limited in RIIO-ED1 than RIIO-ED2.

We recommend that a shorter time period is used in modelling to ensure DNOs receive adequate allowances for the investment that is needed in RIIO-ED2, especially

[24] Data sourced from cost assessment file: "ED2Models_C6 Disag_NonOpVT"

since a step change has been observed and acknowledged by Ofgem, as well as adequately explained.

Importance of qualitative assessment

The only qualitative adjustments made in the benchmarking in this activity are downwards adjustments. We believe that qualitative adjustments need to be made to work both ways: not just negative adjustments where a project is thought to be unjustified, but positive adjustments especially where projects are large, long term in nature and sufficient needs assessed.

This is especially important where DNOs may be considering more bespoke approaches in RIIO-ED2, such as in speed of adoption of EV fleet. Ofgem have considered that suitable needs cases have been met, and stakeholder support has been obtained by DNOs. Despite this, there remains the risk that this expenditure is benchmarked out for DNOs with more ambitious programmes.

The Vehicles EJPs are a key part of delivering our EAP and CVP1. In Draft Determinations, this CVP has been accepted with no reward, albeit subject to cost assessment.

The interlinkages between EJP adjustments, business plan outputs and commitments, and implications for different areas of expenditure all need to be considered as part of the cost assessment approach.

EJPs and Engineering Hub process and assessment

There appear to be a number of cases where DNOs have had reductions applied because of an EJP being provided. Some licensees have subjective assessment with EJPs being rejected, others are only subject to cost modelling

We provided EJPs for all major areas of Vehicles capital investment, which may not be consistent with the submissions from other DNOs. This therefore can cause a consistency/fairness issue across the DNOs, where the only adjustments are negative and no further consideration of the additional evidence to justify the needs case is made in the modelling approach.

Having reviewed the EJP assessment for Vehicles and Transport, we concur that there is a requirement to provide a greater level of justification in relation to the wider benefits that will be realised as a result of delivering the vehicle transition programme. In addition to this, further commentary has been provided setting out why this programme and scale of replacement is being adopted. As we revisited the EJP, a greater level of analysis was focused on articulating the increased benefits of replacing vehicles prior to their end of life, both in terms of our customers and wider core commitments. We understand that in order to achieve this, the wider environmental benefits and whole life cost savings will be considered to ensure a robust and clear justification of investment is provided.

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

We agree with Ofgem's proposed approach to qualitatively assess the HVPs as benchmarking HVPs would not really be appropriate given the complexities of the projects.

Core-Q95. Do you see any merit in setting a HVP threshold for RIIO-ED2, and if so should it be based on the RIIO-ED1 threshold?
We agree that there is merit in setting a HVP threshold for RIIO-ED2, and £25m is a reasonable threshold to apply.
Core-Q96. Do you agree with our proposed assessment approach for faults and ONIs?
We consider that the proposal to assess faults and ONIs together is reasonable, but we propose modifications to the modelling to incorporate an exogenous cost driver of network length. Faults and ONIs are activities that are directly linked to DNOs' quality of service. We have some concern that DNOs' track record on supply interruptions does not play a role in such a model, particularly as the model uses cost drivers that are endogenous and may be correlated with poor performance. This can result in poor performance being funded through the model rather than being identified in the model's residuals. Nonetheless, we understand the pragmatic consideration for the use of endogenous cost drivers in this model. However, we consider that adding an exogenous scale driver to Ofgem's proposed model can improve its performance and reduce endogeneity concerns. To this end, we propose a model with two cost drivers. The first is a composite volume driver of total faults and total ONIs. It is appropriate to weigh each driver based on its respective unit cost. Based on the data from ED1 and ED2 these weights are 7% for ONIs vs 93% for faults. The second variable is a relevant scale variable such as network length. This ensures that faults and ONIs are not funded only on the basis of volumes, which are endogenous, but are also linked to a DNO's scale, which is relatively exogenous. The recommended specification is as follows (one or both time trends may be added): Ln[Faults and ONIs costs]=a+b1[(faults total)$^{.93}$(ONIs total)$^{.07}$]+b2[network length]+error At the start of ED1 there was a change to performance requirements, where Ofgem reduced the GSOP for supply reduction from 18 hours to 12 hours. This led to a step change in supply restoration requirements that introduced additional costs that did not exist in DPCR5. We therefore think that DPCR5 data should be removed from the model. Removing DPCR5 data also improves the model's R-squared, and is consistent with the time period used for other models.
Core-Q97. Do you agree with our proposed assessment approach for Tree Cutting?
We have two key concerns with Ofgem's proposals on tree cutting. The first is that Ofgem uses outdated and inferior data to forecast the volume of spans affected under ENATS 43-8. The second is that Ofgem failed to include maintenance costs under ETR 132. We describe each of these issues in turn. **The approach to volume forecasting of spans affected for ENATS 43 tree cutting-8.**

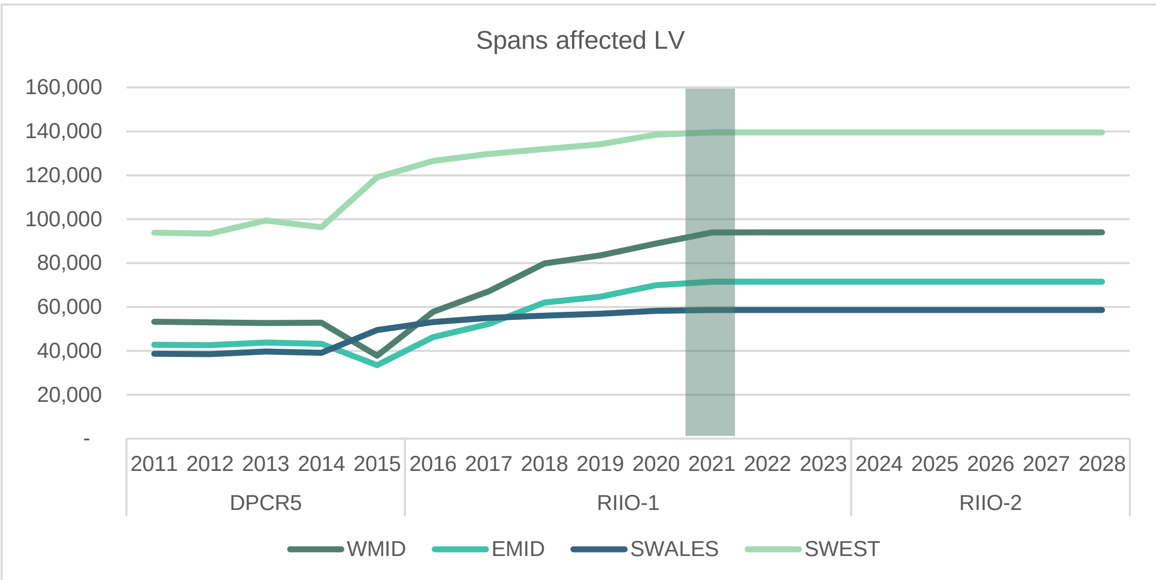
Ofgem's proposed funding approach for tree cutting under ENATS 43-8 is to forecast the number of spans affected by trees and multiply it by a median unit cost at each voltage level.

To forecast the volume of spans affected, Ofgem compares the proportion of spans affected out of total spans over the historical period 2011 to 2021 to the proportion forecasted by DNOs over RIIO-ED2. Ofgem uses the lower between the two as the basis for the volume of spans affected to be funded at RIIO-ED2. For WPD, the historical proportion, or 'run-rate', is used.

This approach is at odds with the approach for deriving median unit cost for the same activity, which does not take DPCR5 data into account. This approach puts significant weight on old, outdated, and inferior data from DPCR5 and early ED1 years. Our information on spans affected on our networks has improved in recent years resulting in a steady but significant increase in the level of spans affected between 2014 and 2020. Our most reliable view of known tree infestation is the 2020/21 value used in our business plan.

Data prior to this year has been corrected and improved and therefore is no longer relevant.

The chart below shows the evolution of our spans affected data on the LV network (the picture for the HV network is similar). Since 2014 we have made steady improvement in understanding the level of spans affected on our networks and we have been updating the numbers every year. Our best view of spans affected is that of 2021, which is what we forecast to the future period despite the significant upward trend in the historical years. This view can be confirmed with outturn data of 2022.



We consider that there is a strong case for Ofgem to use our forecast of volumes to set our tree cutting allowance for ETR 43-8. Taking the average of historical rates may make sense when the rates move as a 'random walk'. Our rates are steadily increasing, and the reason for this increase is clear to us – we have gained better information on spans affected on our networks over recent years. An average of historical years is not the appropriate approach in this case. Nor do we think that an extrapolation of the historical trend forward is appropriate. Rather, an extrapolation of

the most recent and reliable value is appropriate, which is what we have done in our business plan.[25] **The omission of resilience maintenance costs from ETR 132 tree cutting** ETR132 tree cutting costs include two components: costs related to the initial clearance and costs related to the maintenance of already cut clearances. WPD has been proactive during DPCR5 and RIIO-ED1 in carrying out ETR 132 initial cutting. WPD's programme is focussed on the 33kV network. Most will be made resilient by the end of RIIO-ED1. At RIIO-ED2, WPD is moving from an initial cut ETR programme to the maintenance of the already cut ETR clearances. There are therefore only small amounts of initial clearance costs in our business plan forecasted for RIIO-ED2. The vast majority of ETR132 costs at RIIO-ED2 relate to maintenance of clearances rather than the initial cut. Ofgem's assessment is only picking up costs associated with first cut clearance. The models need to be revised to also pick up the cost of resilience maintenance. We raised this issue in SQ WPD010.
Core-Q98. Do you agree with our proposed assessment approach for Severe Weather 1-in-20 Events?
Given that SW 1-in-20 costs are dependent upon severe weather being experienced, it is reasonable for DNOs not to be provided an ex-ante allowance and for the associated costs to be treated as variant allowances. This will ensure that customers only fund the costs incurred by licensees and prevents windfall gains or losses for DNOs. The process for this should be mechanistic, to avoid unnecessary regulatory burden. As per our response to Q56, there should be no cap applied to the variant allowances as SW 1-in-20 storms are outside of the control of DNOs and there is potential for more severe storms due to climate change, the full costs associated with such severe storms should be recoverable.
Core-Q99. Do you agree with our proposed approach to assessing Inspections and Repair & Maintenance costs?
Cut-out inspections Poor condition cut outs have historically been identified to us by the meter operator when they visited the property to read meters. With the advent of smart meters the role of the meter operator has changed regarding house visits and the responsibility to inspect the cut outs falls back on to the Distribution Network Operator. As part of RIIO-ED2 proposal we are introducing a routine inspection programme to assess the condition of every cut out over a 20 year period. This is effectively a new programme for the tail end of ED1 and ED2. Ofgem's cost benchmarking for inspections considers the costs across the whole of ED1 and ED2 and regresses this against MEAV. Since these cut-out inspection costs

[25] We would expect data on spans affected to be stable into the future. We observed that this is not the case for all DNOs.

have not been incurred in most of ED1, included a time period across all ED1 and ED2 effectively halves the costs. We suggest that cut-outs requires its own specific assessment over a shorter time period. **Inspections** While we agree that inspections are linked to the MEAV, the use of a total network MEAV as the cost driver is inappropriate and skews the allowances towards companies that have large underground networks which require minimal inspection activities. The main types of assets that are inspected are overhead lines and substation assets. The driver of inspection costs is therefore the MEAV of overhead lines, switchgear and transformers. It is more appropriate to use a cost driver based upon a sub-level MEAV which excludes cables and services. **Repair and Maintenance** While there are some repair activities that can be carried out on cables, the vast majority of activity is carried out on overhead lines and plant. It is therefore also more appropriate to use a cost driver based upon a sub-level MEAV which excludes cables.
Core-Q100. Do you agree with our proposed assessment approach for NOCs other?
We agree with the proposed approach for Dismantlement. We agree with the proposed approach for Remote Generation Opex. We also propose that because these costs are only seen in 3 DNOs, these should also be an exclusion in the totex models (see Q63 response). While we agree with using DNO own median unit costs in the assessment approach for Substation Electricity, we do not agree with the use of a median unit cost using RIIO-ED1 and ED2 data. WPD’s business plan detailed the reasons for increases in costs through RIIO-ED1[26]: • Use of ‘check meters’ and improved verification process which has made estimated usage more accurate • Continued pressure on electricity prices, including wholesale price increases, Brexit (Carbon Auction – UK not included in EU benefits), Covid uncertainty, volatility in the gas market and increases to non energy commodities (Renewables Obligations, DUOS) (external factors which are now even more exaggerated then December 2021) These unavoidable increases into RIIO-ED2 are therefore diluted in a median cost using ED1 data. Should Ofgem wish to continue to use some element of historical data in benchmarking, we suggest using the last five years of RIIO-ED1, rather than the whole period as this is more reflective of current costs.

[26] WPD RIIO-ED2 BP4 Supplementary Annex 6 – Expenditure, paragraphs 6.146-6.147

Core-Q101. Do you agree with our proposed assessment approach for Smart Metering Rollout?
No. We do not support Ofgem's proposal to remove the Smart Meter volume driver for RIIO-ED2. There is still uncertainty with regards to the timing of the completion of the smart meter rollout programme by suppliers, and now, with the added requirement to potentially replace some previously installed SMETS1 meters, this could result in additional actions for the DNOs. Whilst there is still some policy uncertainty over the smart meter rollout programme we propose the smart meter volume driver is kept in for RIIO-ED2. We also have concerns regarding the benchmarking of forecast activity volumes. In the disaggregated model, Ofgem benchmark the levels of forecast activity to the median forecast RIIO-ED2 intervention rate. WPD forecasts have been based upon our actual ED1 intervention rate, which differs slightly across our licence areas, and in WPD West Midlands and WPD South Wales is higher than the median ED2 rate. The importance of RIIO-ED1 experience is mentioned in paragraphs 7.379 and 7.381, it would therefore be more appropriate for Ofgem to use the actual RIIO-ED1 intervention rate by the different DNOs for benchmarking volumes. We generally agree with the proposed approach to benchmarking of unit costs. Please also refer to our response to Overview-Q5.

Core-Q102. Do you agree with our approach to assessing CAI costs?
We consider that the proposal to assess Closely Associated Indirect (CAI) Vehicles and Transport together with Non-Operational capex is reasonable. We disagree with the proposed approach for assessing the remainder of CAI costs. The proposed approach combines Core CAI costs with the material costs of Operational Training and Wayleaves. The combined cost is assessed with a regression model of a single cost driver, MEAV, and time trends. For comparison, at RIIO-ED1, only the more coherent group of Core CAI activities was assessed through a regression model, and the model used two cost drivers, MEAV and asset additions. Operational Training and Wayleaves were assessed separately. We consider that the proposed CAI regression model for RIIO-ED2 is simplistic, non-proportionate, and insufficiently accurate, producing results which are less statistically robust than at ED1. CAI is a very material area of spend. The RIIO-ED2 approach can be improved in the following two ways: **1. Improved model specification** We recommend a model where CAI is regressed on a composite scale variable (CSV) that includes MEAV, customers and network length at equal weights and asset additions as an additional stand-alone variable. The model can also include time trends, although a time dummy for the RIIO-ED2 period generally appears logical and statistically more robust. This model is both statistically and intuitively more robust than the model proposed by Ofgem.

CAI is composed of several activities whose costs are driven by a combination of scale variables. In our view the dominant common drivers are network length and customers. The CSV that we propose reflects that.

The CSV that we recommend reduces the weight on the MEAV. As we discussed in the response to Q64, MEAV has fundamental flaws. In the context of CAI, a significant flaw is the high weight it places on underground cables compared to overhead lines. This creates a variable that is not fit for purpose to explain variation in CAI costs, which are not affected much by the mix of underground cables and overhead lines.

We also propose to use asset additions in the CAI model. Whilst the CSV is a good explanatory variable when needing an appreciation of scale, it is not a measure of work undertaken and therefore only gives retrospective efficiency assessment of a DNOs past performance. Including a variable that draws on work done alongside scale gives a much more complete and relevant picture. Activities such as System Mapping, Network Design, Project Management and Stores need a count of activity to reveal the reasons behind why a company carries out that activity, thereby generating the costs being assessed.

2. Disaggregation of Core CAI from Wayleaves and Operational Training

We consider that combining Wayleaves and Operational Training with Core CAI is not appropriate for two reasons:

(i) Wayleaves and Operational Training do not share the same drivers as Core CAI activities;

(ii) Wayleaves and Operational Training do not have notable cost reporting issues that may suggest they are non-excludable (per Ofgem's criteria as stated in paragraph 7.69 of the core methodology document).

We understand the desire to simplify the disaggregated approach, including through combining activities to reduce the number of assessment models. However, Wayleaves and Operational Training are material activities that change the composition of the assessed CAI costs. The desire to simplify needs to be balanced with proportionality and, crucially, with the quality and accuracy of cost assessment.

For these reasons, we think that the assessment of Wayleaves and Operational Training costs should be kept separate.

The models that were used at RIIO-ED1 for these 2 activities should be re-established and explored for use at RIIO-ED2:

- Wayleaves used a driver of 'Number of supports (towers and poles)' which appears sensible. The use of underground cables in the model driver for this activity was discounted at RIIO-ED1. On this basis the current RIIO-ED2 method of including Wayleaves in the regression model with a MEAV driver should be discounted for the same reasons. There has been no major change in Wayleaves which merits this change in treatment.
- Operational Training was previously assessed using number of leavers and the current workforce. This also appears more intuitive for this activity and merits further investigation. We also have concern that the current approach causes a significant reduction in WPD's allowance for this activity; this is at a crucial time when networks need to develop more capacity and thus need appropriately skilled resources to be in place. An assessment approach that is more intimately linked with workforce size and requirements would better complement the overall assessment approach.

Core-Q103. Do you agree with the proposed assessment approach for Business Support costs?
We consider that the removal of Property Management from Business Support cost, to be assessed alongside Non-Operational Property activity, is reasonable. Our main concern with the proposed model for Business Support costs is the heavy reliance on MEAV as a cost driver. We consider that MEAV, in its current form where all assets are included with different weights, is demonstrably not an appropriate driver of business support costs. Network length is the most fundamental measure of scale of network companies and is intuitively a more appropriate driver of Business Support costs.

Core-Q104. Do you agree with our approach to assessing streetworks costs?
We agree with the approach to use each DNOs own recent streetworks costs in the benchmarking approach. The Draft Determination correctly acknowledges the wide differences between licence areas driven by different approaches from Local Authorities, which are outside the control of the DNO, and thus the issues that could be caused by a comparative benchmarking approach. We also agree with the exclusion of these costs from Totex modelling, for the same reason. However, we disagree with some specific parts of the approach, which we detail in turn here. We hope that we can work with Ofgem ahead of Final Determination to further address the points raised in this response on Streetworks. The current approach is based on the values of Streetworks cost type in the C1 cost matrices. However DNOs have also submitted detailed memo tables M9a and M9b, which include significant additional costs associated with Streetworks, that are not necessarily disclosed as Street Works, but as Contractors and Labour instead (relating to the additional costs incurred to comply with permit conditions etc.). We consider that the memo table costs are a better reflection of the modelling that should be applied and better reflect the differences across regions (differences which are visible across WPD's own 4 DNOs). We have raised this issue in SQ WPD032. In their response, we note that Ofgem refer to the issue of then "how M9a/M9b costs may better be disaggregated and allocated to individual cost categories" if they are used. We agree this is an issue, but to not take account of the detailed costs provided by DNOs in the M9 memo table on the basis of no existing disaggregation is a flawed approach. We suggest that an initial approach could be to disaggregate the majority of memo costs across activities on the basis of the C1 spread, whilst the admin costs reported on M9 could be assumed as Core CAI (EMCS). Whilst we fully support the decision not to undertake comparative benchmarking, we do think there should be some form of qualitative review between DNOs to ensure consistency of reporting. We note that NPG has a large exclusion compared to WPD (and other DNOs) when there is no perceivable policy influences in these areas. We think that the selection of the base year as average annual costs between 2019-2021 is incorrect. The BPDT RIGs Glossary defined an existing permit or lane rental scheme (which could therefore be included on table M9b) as a scheme in place as at 1st November 2021 and with at least 6 months of cost data relating to the scheme at that date. On this basis, this means that that there will be new schemes that came

into place between 2019 and this date which are not accounted for in the current base year selection. This then underestimates the forecast streetworks costs in RIIO-ED2.

Model data issues

We have identified the following data issues in the Streetworks disaggregated file (ED2Models_MasterTemplate_Disag_Streetworks). We have raised each of these issues in Gitlab. These issues need to be resolved before any further analysis using memo table data is undertaken.

1. Data source of 'Inp_Factors'

   The model uses a trend of underlying activity volumes to calculate future costs. This trend is driven by the sheet 'Inp_Factors' in the streetworks model. However this tab includes hard-coded data only. We request that the source and calculations of this data is shared with DNOs.

2. Missing WPD data in the model

   Data appears to be missing from the input in the models concerning M9b and WMID, SWEST and SWALES. This has been flagged by email to Ofgem (Mark Hogan, Hilary Algert) on 20th August 2022.

   - Tab 'Inp_Costs_M' shows no data for WMID, SWALES and SWEST for Table M9b gross costs in rows 52, 54 and 56. This appears to be because there is no data for these 3 DNOs on tab 'Inp_M'.
   - Further M9b data for these 3 DNOs on tab 'Inp_Costs_M' are hard-coded – see rows 69/71/72, 86/88/89, 103/105/106. The formulae needs to be re-established once the data issue on tabl 'Inp_M' is resolved.

3. Inside and Outside the Price Control data

   Data currently in the 'Inp_Costs_M' tab appears to be a total of Inside and Outside the Price Control. The data formulae need to be amended to pick up Inside the Price Control data only.

Streetworks reopener

We also recommend that further clarity is provided on the Streetworks reopener for RIIO-ED2. Whilst the SSMD set out the approach is to remain largely unchanged to RIIO-ED1, this is not consistent with the reopener developed for RIIO-GD2 and ignores other policy changes since RIIO-ED1. We have reviewed the Specified Streetworks Costs Reopener (SWR) as part of LDWG discussions. In particular, we have recommended that the scope is broadened to cover the changing policy environment, in a manner consistent with RIIO-GD2. Detailed comments have been provided through the LDWG.

We note that the Draft Special Conditions only include one window for an application at January 2026 (and any other window as the Authority directs). In common with the change applied in RIIO-ED1, we also recommend that a close-out window is included at the end of RIIO-ED2, so policy changes beyond January 2026 can be accommodated appropriately.

Core-Q105. Do you agree with our proposal to carry out a demand driven post-modelling adjustment?
We do not agree with the policy behind the demand driven adjustment and we have concerns about the accuracy of the adjustment. Ofgem implements a demand driven adjustment to provide ex-ante funding to DNOs against the same future demand scenario, the FES system transformation scenario. The demand driven adjustment is made alongside the provision of uncertainty mechanisms, in particular two automatic volume drivers (i.e. for secondary reinforcements and for LV services), which, in principle, may allow DNOs to flex their allowed cost upward should they deliver reinforcements against a more ambitious scenario. We consider that a more appropriate policy would be to fund DNOs based on the scenario they adopted in their business plan, in particular where it is based on extensive consultation with stakeholders, supplemented with PCDs and volume drivers to protect customers and ensure they do not pay for work that is not being delivered. This more positive outlook from Ofgem, informed by the regional perspective provided by the DNOs, will have the effect of moving more expenditure into ex-ante allowances rather than being only accessible via a reopener or volume driver. This will provide a very tangible demonstrator of the importance of achieving our Net Zero objectives and remove one of the primary blockers to uptake by the general public. The higher ex-ante allowance would also remove risk of non-delivery due to uncertainty of funding and ensure better allocative efficiency in designing the programme of work compared to a situation where programme design is done piecemeal, with volume drivers as the funding source. This alternative policy approach provides the same protection to customers as the one proposed in DD and does not entail additional regulatory burden. Aside from the point on policy, we also have a concern that a material adjustment of circa £220m for WPD is made on the basis of a single totex model, which is a relatively weak model. We are not convinced that the scale of the adjustment has been carefully checked and triangulated. In our response to Q64 we make suggestions on totex model 3 (e.g. to place a higher weight on heat pumps compared to electric vehicle charges in the composite LCT uptake variable). This would provide an improved model and would have an effect on the demand driven adjustment. We consider that the way Ofgem made the adjustment of heat pumps and electric vehicles based on FES standard transformation scenario has not been transparent. We are in the process of reviewing the numbers in detail and may require more clarification from Ofgem on its approach. Finally, now that FES 2022 data is available Ofgem should adopt it instead of the FES 2021 used for Draft Determinations. Ofgem should use the most recent outlook as a basis for the demand driven adjustment, should it decide to retain the policy.

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

We do not agree with Ofgem's proposal not to recognise and address the link between costs and quality of service.

Contrary to Ofgem's view (as expressed in para 7.425), the issue is not addressed by the overall approach to cost assessment and the calibration of performance targets. The issue is not addressed by the overall approach to cost assessment because the overall approach does not consider the link between quality of service and efficient cost. Importantly, Ofgem's proposed new approach for the calibration of performance targets, such that each DNO's targets are based on its own historical performance, *increases* the need for quality-of-service adjustments compared to where targets were based on, say, industry median.

DNOs have previously been funded through benchmarking models that do not consider quality of service. This means that they are funded to deliver sector average quality of service. The gap between what they are funded to deliver (i.e. sector average performance) and any significantly higher performance target is unfunded.

Making adjustments to address these funding gaps should not be overly complex. The gap between the level of performance funded and the performance target can be easily calculated, and quantifying it can be based on conservative assumptions of marginal costs of improving quality of service. There is no asymmetric risk to consumers, as Ofgem argues. These adjustments can be made symmetrically across DNOs, some positive and some negative.

The lack of linkage between cost assessment and quality of service results in a funding gap, which is an additional efficiency challenge for high performing companies in the sector. We do not agree with Ofgem that the onus is only on DNOs to justify a case for an adjustment. We are not proposing an adjustment for a unique circumstance, rather, we are proposing to address a fundamental and systematic deficiency of the cost assessment framework. Nevertheless, we would seek to develop the issue further and propose a pragmatic approach ahead of final determinations.

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

As previously demonstrated the totex models proposed by Ofgem struggle to deal with the change in load related investment (and in other activities in totex) and as a consequence are weaker statistically compared to totex models in previous, more stable, price controls.

A disaggregated approach is better equipped to deal with the significant change in the nature of services and costs of DNOs between RIIO-ED1 and RIIO-ED2. As such the disaggregated approach should play a more dominant role compared to totex modelling.

We consider, as a minimum, a 50% weight should be placed on the disaggregated approach. In light of the weaknesses highlighted around the totex models Ofgem should consider a higher weight on the disaggregated approach.

Core-Q108. Do you agree with our approach to setting and applying the efficiency challenge using a glide path between the 75th and 85th percentile over a 3-year period?
We do not agree with Ofgem's approach. The quality of the totex models has reduced compared to previous price controls. On that basis, a less stringent, rather than a more stringent, catch-up challenge is appropriate. Below we set out our concerns with the approach and rationale for approach as provided by Ofgem. **1) (In)consistency with RIIO-GD2** One of Ofgem's arguments to justify its approach to move to the 85th percentile is that is it consistent with its approach in the gas distribution sector. As the CMA stated in the RIIO-GD1 re-determination,[27] the catch-efficiency benchmark is context-specific. An argument of consistency, therefore, is not a justification in itself – a reference to the context is required. The contextual points that the CMA accepted in not over-ruling the move to the 85th percentile at RIIO-GD2 were (i) the large outperformance of GDNs at RIIO-GD1, and (ii) the low materiality of the issue. Neither of these points are relevant in the RIIO-ED2 context. At GD1, all GDNs outperformed their allowance, reaching to a sector outperformance of 10.3% by the end of the period. At ED1 some DNOs are underspending their allowance, while others are overspending or breaking even. Total sector outperformance is currently at 3.9% and forecasted to reduce to 2% at the end of the period.[28] This is a very different context to GD1. In the case of ED1 the mixed results and the modest sector outperformance suggest a healthy (and welcome) response by DNOs to incentives provided in a challenging determination. We also point out that the strength of a regulatory framework is not based only on the calibration of incentives and the efficiency stretch in a single price control. The strength depends also on the calibration of incentives and efficiency stretch over the long term. Tightening the level of stretch in response to companies' outperformance under their incentives acts to weaken the regulatory framework and is unlikely to be in the long-term interest of current and future customers. Finally, we note that just as at GD2, the scope to outperform on cost has reduced at ED2 under the draft determinations proposals. The further use of uncertainty mechanisms and PCDs, the indexation of RPEs and reduced TIM rate, and the improvement in the approach to NARM, where the focus is on long terms rather than annual risk removed, all reduce the scope for outperformance.

[27] At GD2, the CMA stated that "Regulators must always consider the case-specific circumstances and set the benchmark at a level appropriate for the case." CMA, GD2 Final Determinations, 28 October 2021, para 12.142.
[28] Ofgem, RIIO-ED1 Network Performance Summary 2020-21, p.8

2) The move to the 85th percentile is material

As at RIIO-GD2, Ofgem is arguing that the move to the 85th percentile is immaterial: "the difference between the 75th and 85th percentile benchmark is relatively small, particularly when applied as a glide path to the 85th percentile."[29]

First, considerations of materiality are irrelevant in this case. Considerations of materiality are relevant in certain situations. For example, for price control re-openers, materiality thresholds help ensure proportionality (i.e. the effort required to re-open a price control may be justified only above a certain materiality). Likewise, a materiality threshold may be appropriate for the assessment of company specific factors to maintain proportionality (e.g. all regions have immaterial specific factors, many of which offset each other within or across regions. It is the material ones that may justify a bespoke assessment).

In situations such as this, considerations of materiality are irrelevant and can lead to arbitrary decisions. The same rationale can be used to stretch the ongoing efficiency just a little more. This is unhelpful regulation. Besides, why should materiality be assessed against the 75th percentile and not against a lower percentile?

Further, using 'non-materiality' to justify a policy today can create an unwarranted precedent for the future, where the impact of the same policy may become material, but the weight of justification may shift to relying on the precedent. Indeed, the precedent of GD2 in respect of the catch-up challenge does exactly that.

Putting this argument aside, the move to the 85th percentile at ED2 is material. The materiality of gliding from the 75th to the 85th percentile at ED2 is about £158m for the sector, or about 0.7% of totex. It is significantly more material than at GD2 where the same move had a £23m impact, or 0.2% of industry totex. The materiality at ED2 is almost <u>four</u> times that at GD2.

It is also material in the eyes of Ofgem. Ofgem uses 0.5% of totex as a materiality threshold in its assessments of company-specific factor claims.[30]

3) The level of catch-up challenge should be linked to model quality, which has deteriorated

Fundamentally, the catch-up challenge needs to be linked to the confidence in modelling results, which in turn depends on the quality of the models. Ofgem's totex models are weak in comparison to totex models used at GD2 and ED1. This supports a less stringent catch-up challenge than the 75th percentile, not a more stringent challenge.

Confidence in modelling results goes beyond model quality for the purpose of determining the catch-up challenge. There needs to be sufficient confidence that the spread of observation about the fitted curve (i.e. about 'modelled costs') represents mainly variations in efficiency. The larger the spread of observations about the fitted curve, the more likely it is that factors other than inefficiency are being captured in the residuals, which in turn undermines confidence in the results. The spread of observations about the fitted curve, as measured by 'efficiency scores', is larger in the ED2 models compared to ED1 and GD2 models.

---

[29] Ofgem RIIO-ED2 draft determinations, core document page 361.

[30] "We have previously set out the following criteria for company-specific factor claims at RIIO-ED2, which we have used in our assessment at Draft Determinations (…) Material: the cost exceeds 0.5% of gross unnormalised RIIO-ED2 totex". Source: Ofgem, 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June 2022, p. 233.

This relatively large spread is understandable. There is significant change and uncertainty at RIIO-ED2 compared to RIIO-ED1. Companies adopt different demand scenarios on which to base their forecasts, and while Ofgem is trying to control for the different scenarios in business plans, it was always going to be a difficult task and ultimately a compromise on model quality and confidence in results. The bottom line is that there is less confidence to interpret variation in efficiency scores as variation in efficiencies across DNOs. Hence more, not less, caution should be taken when setting an efficiency benchmark.

The following table provides a comparison of basic model diagnostics between ED2, GD2 and ED1 and highlights where the ED2 totex models are comparatively weak.

Table: ED2 models quality as compared to ED1 and GD2

	ED2			ED1		GD2
	Totex 1	**Totex 2**	**Totex 3**	**Bottom-up**	**Top-down**	**Totex**
Adjusted R-squared	0.86	0.84	0.80	0.88	0.87	0.92
Range of efficiency scores	0.22	0.35	0.38	0.23	0.25	0.19
Ramsey RESET	Pass	Fail	Pass	Pass	Pass	Fail

The question of the catch-up challenge was subject to dispute in the recent 2019 price review (PR19) appeals in the water sector. At the PR19 final determinations, Ofwat set a catch-up challenge beyond the 75th percentile which the CMA in its re-determination decided to re-set at the 75th percentile. To assess whether a stretch of the catch-up challenge was appropriate the CMA considered “whether there had been a substantial improvement in the econometric modelling”. Since it found that improvement in modelling was not ‘substantial’ it decided against a stretch of the catch-up challenge beyond the 75th percentile. To justify its decision, the CMA argued:

> *“We found that it was more appropriate to set the efficiency challenge based on our assessment of the quality of the econometric modelling, rather than to seek specific outcomes”.*[31]

While the details of the CMA approach can be disputed, the CMA provided a good example of evidence-based and reasoned decision making.

In the case in front of us, at ED2, there is no question whether improvements in totex models was substantial or small. Models’ quality has gone down, and their results less reliable. Yet the unjustified proposal is to further stretch the catch-up challenge. For the reasons set out above, we disagree with the proposal.

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

We welcome the use of annual indexation for Labour and Materials.

We have three key issues with the RPE proposals:

[31] CMA, PR19 Provisional Findings, 29 September 2020, paras 4.294 to 4.295

First, we consider that lack of indexation for Plant and Equipment (P&E) and Transport is not justified. There is clear evidence of a positive wedge between indices that track P&E and transport costs and the CPIH. Lack of indexation for input inflation that we cannot effectively control for does not constitute an efficient allocation of risk and results in an additional efficiency challenge for DNOs. Given that an automatic indexation entails very little regulatory burden (in practice there should be *no additional burden* given that indexation is made for other inputs already) we do not consider that a materiality test is relevant, and it should not present a 'proportionality' barrier for the mechanism in question. The data that informs the materiality test is also flawed: it is based on the cost structure of a 'notional efficient DNO' which has been calculated as the average of the reported cost structure of all DNOs; however there is little guidance on how the 6 input cost categories are defined and so there is scope for inconsistencies in DNO assumptions on how these are built up in their individual returns. The argument for indexing 'Other' costs is less clear but needs to be explored. At a minimum, we would expect Ofgem to set RPEs for P&E and Transport, covering 93% of totex for the notional efficient DNO, which is the same as at RIIO-1. **Second, Ofgem's choice of the Average Weekly Earnings (AWE) index is inappropriate and may give rise to bias.** According to the ONS, "AWE does not differentiate between full-time and part-time workers, and so a relative increase in the prevalence of part-time working would indicate that average weekly pay was falling whereas average hourly pay may remain the same."[32] The ASHE median hourly earnings index may be more appropriate to avoid such bias. **Third, the proposed notional cost structure should be updated to reflect Ofgem's DD cost allowances.** Ofgem calculates the Totex RPE allowance based on a notional cost structure that is derived from the input cost categories that DNOs submitted as part of their business plans (the same notional cost structure has been used to determine materiality, as described above). In its DD cost assessment, Ofgem has disallowed costs from specific cost activities, which may impact on different input cost categories. Therefore, to ensure that the Totex RPE allowance accurately reflects an efficient allowed DNO cost structure, Ofgem must work with DNOs ahead of FD to review the notional cost structure using this updated information. Alongside this response we submit a report prepared by NERA for the ENA, which sets out additional issues related to the proposals on RPEs[33].
Core-Q110. Do you agree with our proposed approach to setting the ongoing efficiency challenge and the level of challenge applied?
We submitted a business plan with an ongoing efficiency (OE) assumption of 0.5% per year. This view is consistent with the evidence. Some DNOs raised their view of OE to 1% between their draft and final business plan citing 'ambition'. We do not consider that ambition has a role in setting OEs, just like it does not play a role in setting the WACC. OEs are based on objective evidence from the wider economy. We should expect the regulatory framework to be rigorously evidence-based and objective.

[32] "An overview of and comparison between Annual Survey of Hours and Earnings (ASHE) and Average Weekly Earnings (AWE): 2017", Office for National Statistics, 2017, section 4.2.2, page 5.
[33] Annex 18, NERA, Response to RIIO-ED2 Draft Determinations on Real Price Effects, prepared for the ENA, 23 August 2022

We still consider that 0.5% per year is an appropriate OE assumption in light of evidence from EU-KLEMS data on productivity improvement in the wider economy, and in light of relevant wider evidence.

We strongly disagree with Ofgem's annual OE rate of 1.2%. This rate is not consistent with the evidence presented. It is also in contrast to recent views and evidence provided by other consultancies, including CEPA, and by the CMA. The 1.2% rate is based on the top range of estimates obtained when using selective data and assumptions. It is based on a set of 'beliefs', which Ofgem has not sought to evidence. The high OE assumption puts DNOs in an unfair position where they would in effect have to absorb the implications of this decision and start ED2 from a position of underperformance on totex.

We provide recent reports by NERA[34] and Frontier[35], both commissioned by the ENA, which set out in detail the reasons for our objection. Below we expand on four issues.

First **the 1.2% does not constitute an efficient allocation of risk** between companies and customers based on the evidence. It is the absolute top estimate from a range of 48 estimates (and only achieved when data for Information and Communications Technology are inappropriately included in the comparator sectors). It is not a P50 value[36] (nor does CEPA suggest that it is), not a 'fair bet' and there is a very high chance that DNOs will not achieve it through ongoing efficiencies at ED2.

We calculate that, if the P50 OE rate is 0.85%, i.e. the mid-point of CEPA's proposed lowest (0.5%) and highest (1.2%) alternatives, then over the five years of ED2 the expected outperformance clawback by virtue of Ofgem's choice of point estimate will be equivalent to the application of an outperformance wedge of 25bps in terms of RORE. This is a material clawback.

Second, **Ofgem's proposals are not evidenced** in the manner proposed by its own consultants. In Ofgem's Core Methodology Document (page 368), Ofgem refers to CEPA's view that the 1.2% rate is "consistent with a belief that in RIIO-ED2 the network companies will be able to achieve efficiencies closer to more dynamic competitive sectors, and that, in the main, such efficiencies will not be captured in the comparative benchmarking process that sets the 'catch-up' efficiency challenge."

CEPA, in its own report (page 7), presents this as a line of argument which Ofgem could deploy <u>should Ofgem have the evidence to support that belief</u>: "[the 1.2% rate] would be consistent with a belief that in RIIO-ED2 the network companies will be able to achieve efficiencies closer to more dynamic competitive sectors, and that the available evidence suggests to Ofgem that in the main such efficiencies will not be captured in the comparative benchmarking process".

Notwithstanding all the evidence that supports a significantly lower rate than 1.2%, Ofgem did not present any evidence to suggest that the above 'belief' holds, nor did it present evidence that such efficiencies will not be captured in the comparative benchmarking process (and, given the proposal to move to the 85th percentile for catch-up challenge, the bar for such evidence is all the higher), or why additional dynamic efficiency is expected from the sector during this transition.

Third, in coming to its decision, **Ofgem disregards evidence beyond the EU-KLEMS data in favour of a downward adjustment**. This includes evidence on

[34] Annex 16, NERA, Response to RIIO-ED2 Draft Determinations on Ongoing Efficiencies, prepared for the ENA, 23 August 2022

[35] Annex 17, Frontier Economics, RIIO-ED2 Productivity Target, prepared for the ENA, 23 August 2022

[36] A P50 value is one with equal probability of out- or underperforming.

economic uncertainty. The OBR[37] and BoE[38] predict low productivity growth in the coming years as a result of a combination of macroeconomic uncertainties (e.g. Brexit, Covid-19, conflict in Ukraine) and long-term UK structural features, the so called UK "productivity puzzle"[39]. The relevance of forward-looking, economy-wide productivity forecasts influenced by short-term macroeconomic factors is relevant for assessing potential OE improvements at RIIO-ED2. At the minimum economic uncertainties counterweight Ofgem's argument that *"[at RIIO-ED2] there should be more potential to deliver productivity growth beyond that recorded historically"*[40] and that *"1.0% appears insufficiently stretching, particularly in light of the transformation change anticipated during RIIO-ED2"*[41].

Fourth, **the implementation of 1.2% OEs prior to the start of the RIIO-ED2 period is not appropriate**. Ofgem starts applying the OE target from the year 2021/22, that is, two years before the start of RIIO-ED2. Applying an OE assumption of 1.2% for the remaining years of RIIO-ED1 is not appropriate. Due to the compounding effect of OEs this has material implications.

DNOs incur (or forecast to incur) expenditure in RIIO-ED1 under a price control framework with a totex allowance that already incorporates OE assumptions, as set at the RIIO-ED1 final determinations. Under the ED1 framework, and consistent with its assumptions, none of the DNOs is forecasting to achieve OEs of 1.2% in 2021/22 and 2022/23. It is inappropriate for Ofgem to re-write the forecasted OEs in these years.

At a minimum, Ofgem must apply a lower OE assumption for the remaining years of RIIO-ED1, one which is consistent with DNOs' expectations. We also expect Ofgem to accept the actuals from 2021/22, which have become available after the publication of draft determinations and apply OEs only from 2022/23 onwards. Not accepting the 2021/22 actuals would be to ignore latest available evidence and re-write history.

Alternatively, we consider that an appropriate implementation approach for OEs is to run totex models with data that includes OEs (actuals and forecast) up to the end of RIIO-ED1 and excludes OEs only from the RIIO-ED2 data. This approach uses RIIO-ED1 totex values that reflect the incentives and assumptions put in place at the RIIO-ED1 final determinations, and better reflect reality. With this approach the ongoing efficiencies of 2021/22 and 2022/23 would already be reflected in the model, and the OE assumption would be implemented from 2023/24 onward.

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

We do not agree with the current disaggregation methodology used in Draft Determinations.

We are supportive of further developing proposals for an alternative methodology with Ofgem and the other DNOs, through CAWG, bilaterals and other appropriate forums ahead of Final Determinations.

We welcome the discussions at CAWG-28 on 23rd August with suggestions of disaggregation based on the disaggregated cost models and a blending of these with the totex models. We will further develop our thinking on this and feedback to Ofgem our detailed observations and proposals in early September.

[37] OBR, Economic and fiscal outlook – March 2022, Table 2.5 and Appendix C.
[38] Bank of England, Monetary Policy Report - August 2022, Table 1.E
[39] A concerted effort to tackle the UK productivity puzzle
[40] Ofgem, RIIO-ED2 Draft Determinations – Core Methodology Document, paragraph 7.472, p.368.
[41] Ofgem, RIIO-ED2 Draft Determinations – Core Methodology Document, paragraph 7.477, p.369.

It is important that DNOs have an appropriate disaggregation of allowances to allow appropriate monitoring in RIIO-ED2. The interaction and impact on Non-Price Control Allocations (net to gross) and the Price Control Financial Model (PCFM) (including capitalisation rates) also needs to be considered as part of the discussions.

The workings and application of the net to gross process in the models needs further discussion, as raised in CAWG-28, and again, we will prepare further thoughts in early September.

It is essential that this discussion is progressed and final agreed proposals shared by Ofgem to DNOs ahead of Final Determinations, to ensure an appropriate way forward is adopted.

Finance Annex

Consultation question on allowed return on debt

FQ1. Do you agree with our approach to estimating efficient debt costs and setting allowances for debt costs?
We note that Ofgem is proposing a cost of debt based on a 17-year trailing average of the iBoxx GBP Utilities 10yr+ index yields, with a 25 basis points (bps) allowance for additional costs of borrowing. A 0.06% infrequent issuer premium has been added to the allowed cost of debt for three licensees: LPN, NPgN and SWALES. However, on the basis above, Ofgem's modelling suggests a 2 bps underperformance under the base case, and a greater risk of underperformance in high inflation or high interest rate scenarios. The setting of a cost of debt which shows underperformance under the base case is in contrast to Ofgem's approach in the RIIO-GD2/T2 Final Determinations, where Ofgem anticipated headroom of 26 to 29 bps under the base case, which declined to 3 to -2 bps where RPI was modelled to be 1% higher. Ofgem also states that the inclusion of derivatives as a cross-check would reduce outperformance (increase underperformance) by 9-23bps under the scenarios shown above. [42] Ofgem stated that "We consider our chosen calibration is robust to various macro-economic assumptions and different potential ways of assessing the sufficiency of the allowance."[43] At the time of the RIIO-GD2/T2 Final Determinations, inflation had fallen sharply and the OBR forecasts for RPI in the coming years had been revised downwards, rising back to a long-term average of 3% in 2025. Since this point inflation has risen such that the current RIIO-ED2 period faces greater inflation risk than that at the time of setting the RIIO-GD2/T2 cost of debt. Similarly, in Q1 2022, the iBoxx Utilities index increased sharply to 3.8%; higher than the peak of March 2020 pandemic, and only previously seen in early 2016. The interest rate risk has therefore also increased for RIIO-ED2, as interest rates and volatility have increased. Consequently, there is a greater requirement to provide headroom at RIIO-ED2 than at the time of the RIIO-GD2/T2 review, to ensure that the RIIO-ED2 calibration is also robust to various macro-economic assumptions. Under Ofgem's modelling, use of the 20-year trailing average of the iBoxx GBP Utilities 10yr+ index yields plus 25 bps for the additional cost of borrowing would provide greater protection with 21 bps of headroom in the base case, falling to 2 bps under the high interest rate scenario, comparable with the calibration for RIIO-GD2/T2. As further cross-check, this would be sufficient to cover the expected RIIO-ED2 debt costs inclusive of derivatives.

[42] Para 2.62, p. 22, Ofgem, RIIO-ED2 Draft Determinations – Finance Annex, 29 June 2022
[43] Para 2.41, p.18, Ofgem, RIIO-2 Final Determinations – Finance Annex (REVISED) , 03 February 2021

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

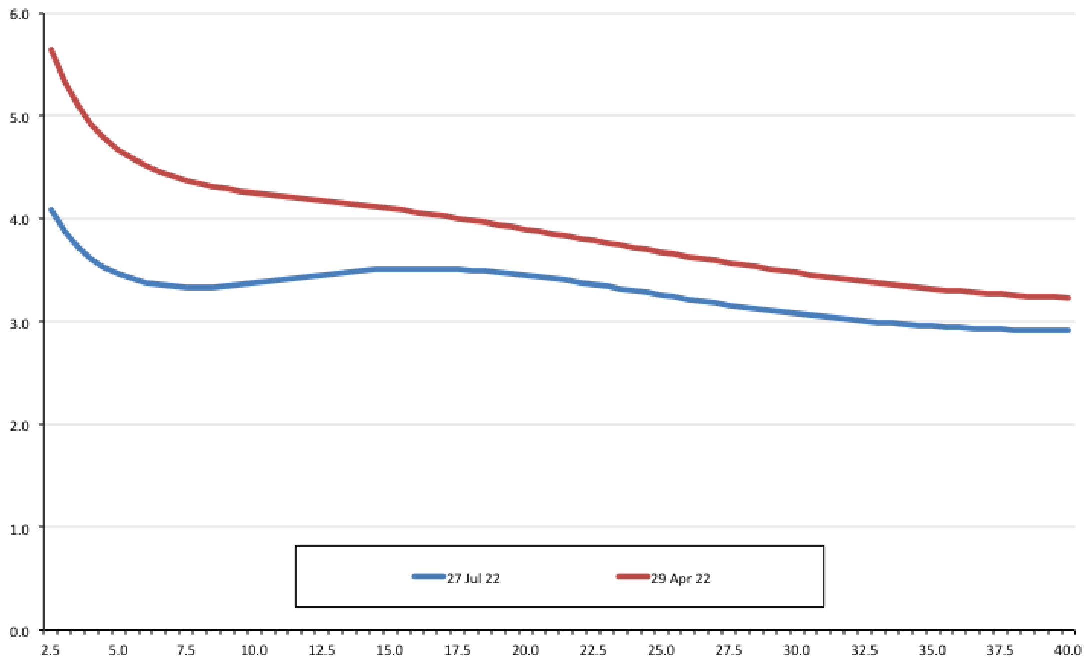
FQ2. Do you have any views on the model to implement equity indexation that is published alongside this document, (the 'WACC Allowance Model - RIIO-ED2 30th April 2022 update Alternative Wedge')?
If the risk free rate (RFR) is to be estimated solely from index-linked gilt (ILG) yields, the approach to RFR indexation (RFR being the only element of the CAPM estimation that should and can practically be updated during a price control) that has been proposed by Ofgem for RIIO-ED2, would seem reasonable, provided a suitable value of the RPI-CPIH 'wedge' is used each year for the annual update to the RFR (see the response to FQ3 below). However, as also explained in the response to question FQ3 below, weight should also be placed on other ways of estimating real risk free rates relative to CPIH. In particular, weight should be placed on nominal high-grade (AAA) corporate bond yields less (i.e. deflated by) expected long-run average CPIH inflation, for which the OBR's long-term CPI inflation forecast would appear the best currently available independent source of a reasonable CPIH proxy to use when estimating the RFR.
FQ3. In light of the upcoming change to the definition of RPI in 2030, should the RPI-CPIH inflation wedge be based on: a) a single year (as shown in the WACC allowance model when: cell D2 is "year 5 forecast" and cell B5 is "01/04/2022"); or b) should it be based on 20 years of inflation forecasts (as shown in the WACC allowance model when: cell D2 is "20 year geometric" and cell B5 is "01/04/2031")?
Ofgem is correct to identify that the impending change to the methodology for calculating RPI is a significant complicating factor when seeking to estimate the RFR from long-duration index-linked gilt yields. When converting yields on RPI-indexed gilts to a corresponding CPIH-stripped risk-free rate, it is important that Ofgem makes accurate allowance for current RPI inflation expectations. Any under- or over-statement of expectations of RPI and therefore of the RPI-CPIH 'wedge' will introduce error into Ofgem's risk-free rate calculation, i.e.: - if Ofgem understates current RPI expectations, it will under-estimate the all-in, inflation-inclusive return that investors expect to make from index-linked gilts and, hence, also under-estimate the current CPIH-stripped equivalent risk-free rate; but - if Ofgem overstates current RPI expectations, it will over-estimate the all-in, inflation-inclusive return that investors expect to make from index-linked gilts and, hence, also over-estimate the current CPIH-stripped equivalent risk-free rate. The key thing is that the RPI-CPIH wedge that is used needs to be consistent with the basis on which the RPI-linked gilts are being priced in the market. Importantly, the expectations that matter here are not Ofgem's expectations, network companies' expectations or the expectations of any individual forecaster (e.g. the OBR). Rather, the conversion out of RPI real yield has to capture the expectations that buyers of index-linked gilts have as they make their purchases.

An investor that is pricing an index-linked gilt in today's market will be aware of the announcement made by the UK Statistics Authority (UKSA) and HM Treasury in November 2020 which stated that Authority intends that the methodology for calculating RPI will be brought into line with the methodology for calculating CPIH from February 2030. The investor will also be aware that the decision is the subject of an ongoing judicial review and that there has been a discontent from pension funds and other investors in response to the government's refusal to compensate holders of RPI-denominated financial instruments.

Given this backdrop, an investor in the index-linked gilt market will have to form expectations not just about the future level of inflation but also around the likelihood that the transition to CPIH will actually take place as intended on the timetable that the UKSA has signalled.

Figure 1 plots the so-called break-even inflation curve as at 30 April 2022 (i.e. the cut-off date for Ofgem's DD analysis) and at 27 July 2022.

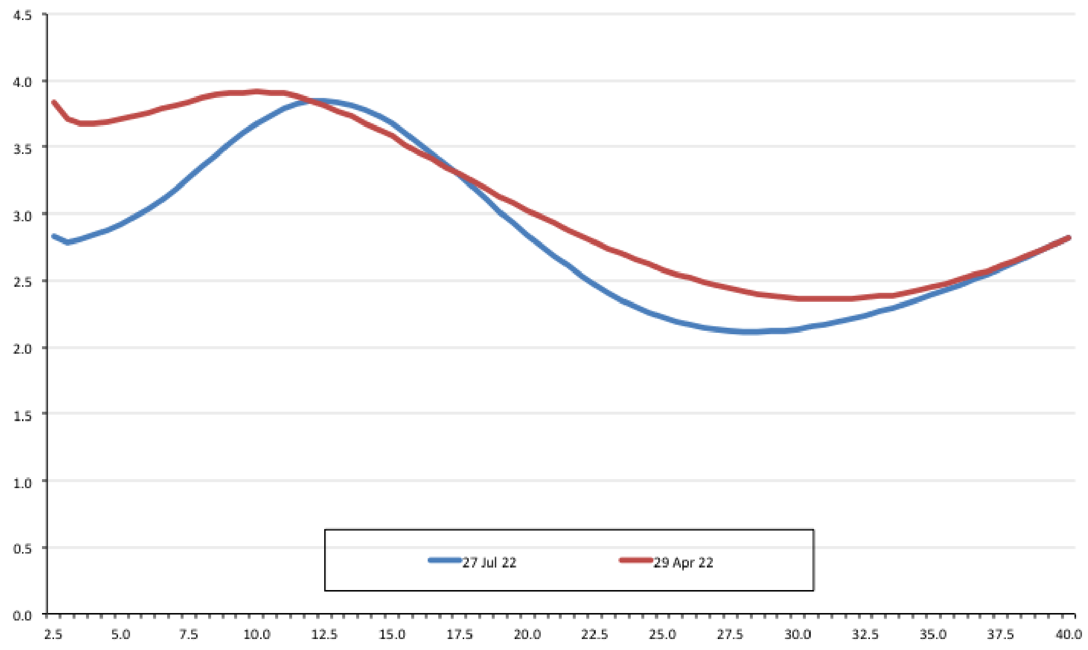
Figure 1: Difference between the yields on nominal and index-linked gilts (%)



Source: Bank of England website.

Figure 2 then further develops the picture by unpacking the data in Figure 1 into an instantaneous forward curve (i.e. a set of estimates of the prevailing rate of inflation at each moment in time over a 40-year horizon). We consider that the chart is helpful because it helps to identify how the break-even inflation shown in Figure 1 builds up.

Figure 2: Instantaneous forward inflation curve (%)



Source: Bank of England website.

It can be seen straight away that the chart is extremely counter-intuitive. The two lines in Figure 2 are remarkable as regards both:

- the *level* of "break-even" inflation from February 2030 onwards – i.e. up to 4% per annum versus the government's CPI inflation target of 2% per annum; and
- the *shape* of the forward curve – i.e. with expectations for inflation increasing up to 2034 then decreasing fairly slowly up to 2050 before then increasing again in the 2060s. It can also be seen that there is no clear step down (by an amount which would be expected to be of almost 1%) in the value of the future breakeven (RPI) inflation around 2030 (year 8 in the above chart) to suggest that the future change to the formulation of RPI in 2030 is as yet being reflected in the pricing of index-linked gilts

We cannot conceive of any rational economic explanation for the story that Figure 2 tells.

Stepping right back, we consider that this evidence puts a serious question mark against Ofgem's over-arching decision to focus exclusively on index-linked gilt yields as its benchmark for the risk-free rate of return. In our business plan, we supported the CMA's preferred approach of using a wider basket of instruments to estimate the risk-free rate. In its accompanying report, Frontier Economics said that[44]:

> *We note the potential downward bias of the ILG yield as a proxy for estimating the RFR, due to the unique features of the government bond which could lead to convenience premium.*

[44] "Cost of Equity Assessment for RIIO ED2: An updated report prepared for WPD", 16 November 2021, Frontier Economics, Section 2.2 page 9

Further evidence in support of this view is also given in Oxera's latest report for the ENA[45], especially section 2.1 which concludes "*Based on the collective evidence above, we consider that Ofgem erred in setting the RFR at the level of the yields on ILGs, and should have placed weight on other rates achieved by highly-rated borrowers. An average of the yields on the UK 20-year ILG and the iBoxx £ Non-Gilt AAA 10+ and 10-15 indices would provide a pragmatic and simple approach to recognising the convenience yield in the estimate of the RFR*."

The evidence we see above validates this sentiment and reinforces the sense that there is a "specialness" to index-linked gilts which can mean that prices and yields are divorced from normal market and economic fundamentals. At the very least, any right-minded person looking at Figure 2 above would have to conclude that there are extraneous factors that are at play that make it extremely difficult to interpret what reported yields mean. In the circumstances, we do not consider that Ofgem can have a sufficient level of confidence in the data to put sole weight on index-linked gilts as its sole proxy for the CAPM risk-free asset.

A clearly better approach would be for Ofgem to follow the CMA's lead and expand the basket of proxies to include, for example, AAA non-government bonds[46]. The theoretical basis for such an approach was set out in detail in the CMA's 2020 PR19 report, and we remain of the view that the CMA gave a compelling explanation of the best way of estimating the risk-free rate using the available market data in the PR19 redetermination. For example, ILG yields are affected by unique features of government bonds which could lead to a convenience premium and thus affect their suitability as a proxy for the RFR, whereas AAA-rated corporate bonds were included by the CMA in the estimation of the RFR as the CMA assessed that this reflects the lowest risk investment which is available to all relevant market participants[47]. Although the CMA did not find Ofgem's estimate of the RFR (based only on 20 year index-linked gilt yields) to be wrong in the RIIO-T2/GD2 appeals, in that case the CMA did not need to opine on precisely how it would estimate the RFR or how best this should be done. It is therefore preferable to adopt an approach consistent with the CMA PR19 determination, where the CMA described carefully the method that it considered to be clearly superior when estimating the RFR.

Importantly, an estimate of the real RFR relative to CPI(H) that is found by deflating the yields on highly rated nominal corporate bonds (AAA-rates) will not suffer from the problems caused by the potential future change to RPI in 2030, as no equivalent substantive changes to the formulation of CPI(H) are expected. Therefore, the initial estimate of RFR for RIIO-ED2, and annual updated values of the RFR during the price control, should give due weight to these data. In the absence of established and independent forecasts of future CPIH, the OBR's long-run CPI forecast of CPI (i.e. 2.0%), consistent also with the Bank of England's inflation target, should be used to convert the yields on these nominal instruments to a real rate relative to CPIH for use in RIIO-ED2.

Note also that 20yr nominal gilt yields deflated by an estimate of the average level of CPIH inflation over the next 20 years would give a notably higher estimate of real RFR than the ILG yield plus RPI-CPIH wedge, even if this wedge is consistent with its previously observed level (as would be estimated at present using method referred to as (a) in the text of question FQ3). Further reducing the latter estimate of real RFR,

[45] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022
[46] This was the approach used to estimate the range for the risk free rate in our business plan, based on data over a 6-month period leading up to the submission of the business plan and so, given the changes in market rates since then, this range now needs to be updated.
[47] "Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations Final Report", CMA, 17 March 2021, see for example paragraphs 9.264, 9.160 and 9.162

by using the method referred to as (b) in the text of question FQ3 and which gives a smaller RPI-CPIH wedge, would add to this inconsistency, and call further into question a reliance on index-linked gilt yields as a measure of the RFR.

The issues and uncertainties raised by this question FQ3 therefore add to the issues recognised by the CMA in the PR19 appeal determination which led to the conclusion in that appeal that full reliance should not be placed on ILG yields when estimating the RFR. The CMA determined instead that weight should be placed also on AAA bond yields deflated by an appropriate estimate of long-run future inflation.

As well as noting the potential downward bias of the ILG yield as a proxy for estimating the RFR referred to above, Frontier Economics' updated report for WPD also recognised the potential upward bias of the AAA corporate bond yield due to possible default risk premium, inflation premium and/or liquidity premium[48]. Frontier Economics have recently updated their earlier estimates, and using average data from the past 6 months find these now give a range for the Risk Free Rate from -0.95% (based on Index-linked gilt yields) to 0.43% (based on AAA bond yields)[49]. It is worth noting that these 6-month averages don't fully reflect the increase in yields in recent months, and by the time the RIIO-ED2 determination is finalised higher values would be expected. For example, at the end of July 2022 the 20-year index-linked gilt yield has risen to -1.07%, so applying the OBR's RPI-CPI wedge of 0.7% (based on latest OBR year 5 forecast) to convert into CPIH real terms would give a value of -0.38% for the bottom of the range (c.f. -0.95% above). A similar increase in the top of the range would also be expected.

For the reasons alluded to above, and explained more fully in the CMA's PR19 redetermination (concluding at Paragraph 9.264), "*We consider that, on balance, it is likely that the RFR appropriate for a range of relevant investors sits above the return available from ILGs, but below the level suggested by the return on AAA bonds*." This suggests that values at the ends of the range indicated above should be excluded, and a reasonable estimate of the RFR would, as in the PR19 redetermination, be near the middle of the range, i.e. c.-0.26% based on average data over the past 6 months (albeit consistent with Ofgem's proposed cost of equity indexation approach, which uses data values during the month of October, this estimate will need to be further updated prior to the finalisation of the RIIO-ED2 Final Determination based on the October 2022 average 20 year ILG yield and iBoxx AAA gilt yields, and then updated again each year based on new October data each year).

We now conclude this question response with a specific response to the narrow question raised in FQ3, which would be most relevant should Ofgem disregard the information and discussion above and instead continue to rely solely on index-linked gilts when estimating the RFR:

Whilst there might superficially seem to be some logic to approach (b), the shape of the daily forward curves for breakeven inflation which are referenced to RPI and published each day by the BoE suggests the change to RPI in 2030 is not yet actually reflected in the relative pricing of real and nominal gilts (see Figures 1 and 2 above). Therefore, approach (a) to estimating the RPI-CPIH wedge would still be better justified than approach (b) at present (and at the start of RIIO-ED2).

[48] "Cost of Equity Assessment for RIIO ED2, An updated report prepared for WPD", Frontier Economics, November 2021, Section 2.2

[49] Annex 7, Frontier Economics, Cost of Equity – Response to RIIO ED2 Draft Determinations, a report prepared for WPD, 23 August 2022

However, this approach might be expected not to remain appropriate during the years of RIIO-ED2, because - if the change to RPI in 2030 is expected to proceed - there is likely to be a mismatch between (i) the point in time at which the OBR forecasts for future RPI and CPI converge and (ii) the point in time at which market pricing and the BoE forward curves reflect this future change to RPI. This matters because a key requirement when seeking to estimate the RFR from index-linked gilts yields is that the RPI-CPIH wedge that is used needs to be consistent with the basis on which the RPI-linked gilts are being priced in the market. For this reason, to the extent that weight is placed on index-linked gilt yields adjusted for the RPI-CPIH wedge, the average RPI-CPIH wedge since 2005 when CPIH was first published[50], i.e. c.0.85%, should, in the context of RIIO-ED2, be used to convert the real rate relative to RPI to a real rate relative to CPIH – at least until such a time as the shape of the BoE forward breakeven inflation curve clearly reflects the possible change to the formulation of RPI in 2030. At that point, a switch to method (b) would seem appropriate.

Alternatively, an approach based on the average of the RPI–CPI wedge implied by 20-year RPI and CPI swap rates, as recently considered by Oxera, could be used[51]. After recognising the need for a further adjustment for the expected difference between CPI and CPIH based on the long-run average CPI-CPIH wedge from June 2002 to June 2022 (10bps), Oxera estimate that this approach currently gives an expected average RPI-CPIH wedge for the next 20 years equal to 0.56%.

Step 1 - Consultation questions on TMR

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

In our business plan, WPD proposed a range for total market return from 6.3% to 6.9% (real, relative to CPIH). This range was calculated using the historical ex post approach, considering a number of averaging methods, holding periods and two methods for deflating nominal historical returns. It also took account of the CMA's judgement in the RIIO GD2/T2 appeals and its analysis from PR19 determinations, and so the top end of the range was truncated (i.e. reduced) by excluding all the data points calculated using (i) the Cooper and DMS average methods, and/or (ii) the CED/RPI inflation series.

Further detail behind the above range was set out in Frontier Economics' November 2021 report[52]. Commenting on this range, Frontier Economics noted that "*Our range is still higher than that of Ofgem's range, as we have reasonably strong evidence to believe that Ofgem's range is underestimated, despite the fact that the CMA has given Ofgem the margin of appreciation. On the other hand, our range is also lower than that of CMA's PR19 both on the upper end and the midpoint, due in part to our exclusion of CED/RPI data points and in part to the updated DMS 2021 data that includes the 2020 equity returns.*"

However, this report was written before the recent publication by the ONS of a new CPIH back-series covering the period from 1950 to 1988. Similarly, Ofgem's 6.5% estimate of TMR (real, relative to CPIH) in the RIIO-ED2 Draft Determinations has not

[50] See Consumer price inflation tables - Office for National Statistics, Tables 6a and 36
[51] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022, Table 2.1
[52] See Section 3 in "Cost of Equity Assessment for RIIO ED2", An updated report prepared for WPD by Frontier Economics, 16 November 2021

been updated from RIIO-T2/GD2, and so is based on calculations that use data that has now been superseded (specifically the ONS's modelled CPI backcast for the years form 1950 – 1988 as published in 2014). Both our TMR estimate, and Ofgem's should now be updated (i.e. in broad terms increased by c.0.25%) to take account of this new CPIH back-series, as explained more fully below. Our own estimated TMR range should then also be increased further by around.0.15%, to take account of the relatively high equity market returns in calendar year 2021, which reflected a recovery to pre-COVID levels following the negative returns in 2020, but which had not yet been included in DMS's latest annual update of historic returns that was available at the time of the Frontier report in November 2021.

Ofgem's RIIO-GD2/T2 estimate of the TMR was based on data that was available to Ofgem as at December 2020. Since that time:

- two additional data points have been added to the historical record of stock markets returns for the years 2020 and 2021; and
- the ONS has released a revised backcast of CPI for the period 1950 to 1988, together with a brand new backcast of CPIH for the same period.[53]

The inclusion of these two additional years of data (unlike the inclusion of just the first of these years in Frontier's report, i.e. inclusion of 2020 data but not the subsequent 2021 returns data, because of the timing of that report) does not have a significant impact on the calculated historical TMR. However, the ONS' new backcasts are material. Specifically:

- the ONS' estimate of CPI inflation between 1950 and 1988 is now, on average, 0.22 percentage points per annum lower than the figures that Ofgem relied upon when assembling its RIIO-GD&T2 estimate of the TMR[54]; and
- the ONS' estimate of CPIH inflation during this same period is on average 0.82 percentage points lower than the previous CPI inflation series that Ofgem relied upon when assembling its RIIO-GD&T2 estimate of the TMR[55].

WPD considers that it is essential that the RIIO-ED2 TMR is (a) based on the latest available data; and (b) makes use of the best available series for historical inflation.

On the second of these points, WPD notes that Ofgem is ultimately seeking to estimate the TMR in real, CPIH-stripped terms. Previously it used historical CPI inflation as the best available proxy for CPIH inflation during the period 1950 to 1988. The ONS' new work shows that, in fact, this series likely overstated actual CPIH inflation. It follows that Ofgem can improve the accuracy of its estimate of the historical CPIH-stripped TMR by switching to the new CPIH backcast in place of the ONS' previous, but now withdrawn and out-of-date, CPI backcast.

WPD notes that the effect of this change will be to increase Ofgem's estimate of the historical TMR by approximately 25 basis points from 6.5% to 6.75%[56]. This is still lower than our own TMR estimate, which we continue to consider is well justified by the available evidence: our previous range from 6.3% to 6.9% has now been updated by Frontier Economics, using the same method as previously but with the latest equity return data and the new ONS back-cast CPIH data starting from 1950. In this new report, Frontier conclude that the updated TMR range should now be from 6.7%

[53] See: https://www.ons.gov.uk/economy/inflationandpriceindices/articles/consumerpriceinflationhistoricalestimatesandrecenttrendsuk/1950to2022 and https://www.ons.gov.uk/economy/inflationandpriceindices/methodologies/consumerpriceinflationhistoricalestimatesuk1950to1988methodology
[54] Annex 14, Oxera, Assessing the new ONS CPIH back-cast, prepared for the ENA, 15 August 2022, Table 3.2
[55] *Ibid*
[56] *Ibid*, page 6

to 7.3% in CPIH real terms[57]. This range can also be seen to be broadly consistent with the value reached by Oxera in its new report for the ENA, which explains that "*Correcting for Ofgem's errors on inflation and averaging, the real-CPIH TMR estimate would be between 7.1% and 7.2% based on the arithmetic average of the historical yearly returns".*[58]
FQ5. Can stakeholders confirm their view on the trade-off between: the objectivity of using outturn averages (even though the results may be materially higher or lower in future price controls than current TMR expectations); versus the benefits of putting more weight on current expectations (noting the evidence from cross-checks and the associated risk of subjectivity)?
In our business plan, WPD calculated the range for total market return using the historical ex post approach, in line with the overwhelming weight of UK regulatory precedent. The preferred approach places most weight on this method, suitably applied using appropriate choices for such matters as the averaging method used, the holding period and the measure of inflation used to deflate nominal historic returns, because it is the method that is least dependent on assumptions and therefore is the most objective and reliable. Our approach, supported by the Frontier Economics report, also took account of the CMA's recent judgement at the RIIO GD2/T2 appeals and its analysis from PR19 determinations, where most weight was placed on the use of outturn averages. For example, in the Final Determination of the RIIO GD2/T2 appeals the CMA observed that Ofgem's TMR point estimate and range had been derived from its analysis of historical returns, i.e. Ofgem did not change its estimate on the basis of forward-looking cross-checks, although it did take comfort from those cross-checks that its historical ex-post estimate was appropriate[59]. One big advantage of using the historical ex-ante approach based on outturn averages is its consistency, predictability and objectivity. A change away from this approach – particularly where this would transfer the setting of a key price control parameter from an objective estimate to the subjective view of a regulator - would be a fundamental change in setting price controls that would be expected to increase investors' perceived risk and thus both beta and required cost of equity. Any change would therefore need to be considered very carefully, with a suitable upwards adjustment to beta or cost of equity being made at the same time (although quantifying the required increase would be difficult, given that the change in risk wouldn't yet be reflected in the available market evidence for beta). The government's "Principles for Economic Regulation"[60] explicitly recognised the importance of, and the Government's commitment to, stable and predictable regulatory frameworks to facilitate efficient investment and sustainable growth. In particular, under the principle of "*Predictability*", the document emphasized that: • *the framework for economic regulation should provide a* ***stable and objective environment*** *enabling all those affected to anticipate the context*

[57] Annex 7, Frontier Economics, Cost of Equity – Response to RIIO ED2 Draft Determinations, a report prepared for WPD, 23 August 2022, Section 3 pages 13 to 15.
[58] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022, page 17
[59] "*Cadent Gas Limited, National Grid Electricity Transmission plc, National Grid Gas plc, Northern Gas Networks Limited, Scottish Hydro Electric Transmission plc, Southern Gas Networks plc and Scotland Gas Networks plc, SP Transmission plc, Wales & West Utilities Limited vs the Gas and Electricity Markets Authority*" CMA Final determination Volume 2A: "*Joined Grounds: Cost of equity*", 28 October 2021, Paragraph 5.285
[60] "Principles for Economic Regulation", Department for Business, Innovation and Skills, April 2011, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/31623/11-795-principles-for-economic-regulation.pdf

for future decisions and to make long term investment decisions with confidence; and

- *the framework of economic regulation* ***should not unreasonably unravel past decisions****, and should allow efficient and necessary investments to receive a reasonable return, subject to the normal risks inherent in markets*

Similarly, the government's recent "Economic Regulation Policy Paper", which referred back to the 2011 principles, also recognised again the importance of predictable regulation and noted that "*Transparent and predictable regulatory frameworks are vital to facilitating investment, protecting consumers, and delivering sustainable growth*".[61]

The Electricity and Gas Acts similarly requires Ofgem to have regard to "*the principles under which regulatory activities should be* ***transparent****, accountable, proportionate,* ***consistent*** *and targeted only at cases in which action is needed;* ...". Thus, both the government's principles for economic regulation and Ofgem's duties under the Electricity and Gas Acts support the continued use of an objective and predictable approach that is consistent with regulatory precedent and has been used in past price controls, and Ofgem should not contemplate making unanticipated changes to this unless these changes are clearly justified.

For these reasons, we consider that Ofgem should continue to estimate Total Market Return using the ex-ante historical method.

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

Notwithstanding that we continue to disagree with certain elements of Ofgem's approach to estimating the TMR, as set out in WPD's business plan and the accompanying expert report by Frontier Economics (now updated) and in Oxera's new report for the ENA (as noted above in the response to FQ4), we consider that Ofgem is required to update its mid-point TMR value to no lower than 6.75% in its RIIO-ED2 Final Determinations, if only to reflect the use of the ONS's recently published CPIH backseries from 1950 to 1988 rather than the superseded CPI series for 1950 to 1988 that was previously available and used. To do otherwise would be an error in that Ofgem would be taking a calculation of the cost of equity that Ofgem knows, thanks to the ONS' new work, contains a miscalculated benchmark for historical stock market returns.

A simple 0.25% upwards revision to Ofgem's estimated TMR range and point value would still give values that we consider to be too low. Instead we consider Frontier's updated range for TMR to be well justified by the available evidence, as referred to in our response to FQ4 above: this is a range from 6.7% to 7.3% (real relative to CPIH) with a mid-point of 7.0% and is based on more recent data, as described and contained in Frontier's latest updated report[62],

Frontier's range can also be seen to be consistent with the values reached by Oxera in its new report for the ENA, which explains that "*Correcting for Ofgem's errors on inflation and averaging, the real-CPIH TMR estimate would be between 7.1% and 7.2% based on the arithmetic average of the historical yearly returns".*[63]

[61] "Economic Regulation Policy Paper", January 2011, Department for Business, Energy and Industrial Strategy
[62] Annex 7, Frontier Economics, Cost of Equity – Response to RIIO ED2 Draft Determinations, a report prepared for WPD, 23 August 2022, Section 3 pages 13 to 15.
[63] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022, page 17

Step 1 - Consultation questions on beta

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

There are clearly many similarities between the regulatory frameworks for the GD, GT ET and ED sectors, which at first sight might suggest that the starting point would be that networks operating in these sectors have broadly similar systematic risk. The systematic risk faced by the companies in these sectors depends, though, on the interaction of this framework with the activities, operations and obligations of the companies, as well as the uncertainties they face, and for this reason their risks can in practice be different.

There is now an increasing focus on Net Zero - including the need for decarbonisation of heating and transport - and the role that networks, and especially electricity networks, will play in delivering this. This will significantly increase investment and create greater uncertainties (at least in the short term) and as a result, all else being equal, this will increase systematic risk.

To the extent that these changes are now more firmly established than during the development of RIIO-T2/GD2, systematic risk (and the market's appreciation of the level of this risk) across the energy network sectors will have increased, especially in electricity.

There is also now heightened political risk, including as a consequence of concerns over rising energy bills, than when RIIO-T2/GD2 was being developed. For this reason too, a higher level of systematic risk should now be recognised in RIIO-ED2 than in RIIO-T2/GD2, although this could alternatively be viewed as a higher level of asymmetric downside risk that should instead be reflected in the choice of a point estimate for beta within the plausible range.

In our draft Business Plan, we estimated a range for equity beta at 60% notional gearing from 0.76 to 0.82, supported by Frontier Economics November 2021 update report. This is higher than the range used by Ofgem in RIIO-T2/GD2, which had a mid-point of 0.759. The lower bound of our range was based on the GB water networks which tend to be exposed to less risk than energy networks (as is evident from the lower water company betas in Ofgem's estimates which persisted across all estimation windows); the upper bound was based on National Grid and other European comparators. A new updated view of the available data by Frontier Economics indicates a similar range, from 0.73 to 0.80, which again has a mid-point that is higher than the RIIO-T2/GD2 value.[64]

The supporting analysis for the values in the business plan was presented in a report by Frontier Economics[65]. As this report explained, whilst it is useful to include the three water companies in the comparator sample (given that they are at least GB utility companies and there are only 2 publicly listed energy companies that own energy networks in GB), water networks tend to be subject to lower risk than energy companies. This was evident from the lower water betas in Ofgem's estimates which persisted across all estimation windows. However, given water companies tend to be lower risk, this could result in underestimating the unlevered beta for WPD. Additionally, whilst NG is the closest comparator to WPD, it did not operate in the electricity distribution sector prior to the recent purchase of WPD. To reduce the risk

[64] Annex 7, Frontier Economics, Cost of Equity – Response to RIIO ED2 Draft Determinations, 23 August 2022, Section 4, pages 20 and 21.
[65] "Cost of Equity Assessment for RIIO ED2, an updated report prepared for WPD", Frontier Economics, 16 November 2021.

of underestimating the beta for WPD, and to ensure sufficient similar comparators, Frontier therefore expanded the comparator sample to also include European energy networks. These EU networks were found to have unlevered betas that were consistently higher across different estimation windows and averaging periods than the UK water companies: the unlevered betas for the EU comparators were also close to, and on average slightly higher than, those of the National Grid.[66] The same observations apply also to the beta information in Frontier's latest report[67]. Oxera's latest report also addresses the question of beta estimation – and considers that "*Ofgem has erred in selecting its sample of comparators by giving too much weight to some comparators, and not enough (or no) weight to others that should have been included in the sample to reflect the systematic risk of GB energy networks more accurately*."[68] In particular: • Ofgem is disproportionately reliant on water companies to estimate the beta of energy networks. Oxera's analysis shows that National Grid's asset beta has been consistently higher than the average asset beta of the water comparators, and the asset beta of the average of the water companies has, in some of the regressions fallen below the lower bound of the confidence interval for the NG beta estimate. This is supportive of a difference in the systematic risk of the UK listed water companies and National Grid. It is also notable that the water network companies operate in a regime which has lower regulatory discretion due to the redetermination process. • Ofgem fails to consider a broader set of evidence and to include European energy comparators in its sample: Oxera's study demonstrates the similarities in the regulatory risk exposure of the European networks relative to the UK energy networks and differences between UK water and energy networks. This explains "*why it is an error to give weight, in the exercise of regulatory judgement, to UK water beta comparators (notwithstanding their difference from UK energy) while giving no weight to European energy beta comparators (notwithstanding their similarity to UK energy)*[69]."
FQ8. What are your views on the relative risk comparison shown in Table 10?
We consider the analysis in Table 10 to be incomplete. It is important that Ofgem recognises the additional risk in the electricity distribution sector and the increased risk from RIIO-ED1, given: - the increased level of investment required to deliver net zero, (albeit this is a risk that applies to electricity transmission as well as electricity distribution), - the focus on downside only incentives, - the level of uncertainty mechanisms in RIIO-ED2, resulting in increased risk that additional allowances to recover such expenditure are not received, or are inadequate, resulting in a Totex overspend against allowances; and - the significant potential changes in the sector e.g. Ofgem's proposals for Access SCR, which will be subject to further consultation in September 2022, and for

[66] "Cost of Equity Assessment for RIIO ED2, an updated report prepared for WPD", Frontier Economics, 16 November 2021, Table 3 1
[67] Annex 7, Frontier Economics, Cost of Equity – Response to RIIO ED2 Draft Determinations, a report prepared for WPD, 23 August 2022 Table 3
[68] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022, page 18
[69] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022, page 22

which the funding arrangements between ex-ante and uncertainty are still unclear.

Consequently, there is a need to reflect these increasing risks in the electricity sector fully when setting the cost of equity (either through a compensating upwards adjustment to the equity beta or by 'aiming up'), given the need to secure finance in the sector. The role of the Electricity Distribution networks is key in ensuring the UK gets to net zero, and therefore investment in the distribution network is fundamental to ensuring this can be achieved.

See also the report "RIIO-ED2, balance of risks", prepared for the ENA by Oxera, which provides further detail on the risks under RIIO-ED2[70].

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

As the most weight was previously placed on long estimation windows/averaging periods, and averaging a large number of values based on different sample lengths/averaging periods, material changes in the data and its interpretation wouldn't be expected since the RIIO-T2/GD2 Final Determinations – although increases in risk not yet reflected in the data (see FQ7 above) should be taken into account when choosing a point value.

In the RIIO-T2/GD2 Appeal, Ofgem told the CMA[71] that there are two ways to interpret its unlevered beta estimate of 0.311: either a) as broadly the average of the three 10-year beta measurements for National Grid; or b) considering all of the data with a 70 per cent weight on the pool of National Grid betas and 30 per cent weight on the pool of water betas. The beta evidence in the RIIO-ED2 Draft Determination Finance Annex (Table 32) as at 30 September 2021 compared to that in RIIO-T2/GD2 Final Determination (Table 10) using data up to end October 2020 doesn't support there being any material change in beta. Applying consistent approaches to those used in RIIO-T2/GD2 as explained above, National Grid's 10 year beta values are on average slightly higher than when RIIO-T2/GD2 was being set, whereas the weighted average of National Grid's beta values (70% weight) and pool of water company betas (30% weight) using all the data points is virtually unchanged.

Even more recent beta values (up to end June 2022) are shown in Frontier Economics' latest update report at Table 3[72]. This again shows that the average of National Grid's 10-year unlevered beta values for spot, 2 year, and 5 year averages has increased slightly compared to the equivalent values in Ofgem's RIIO-T2/GD2 Final Determination at Table 10 (by just over 0.01), whereas the 70:30 weighted average of National Grid and water company unlevered betas across all sample lengths and averaging periods has fallen slightly (by less than 0.01).

Oxera's latest report also shows, in graphical form, how 2 year, 5 year and 10 year betas for National Grid and UK water companies have changed since December 2019[73]. Both 5 year and 10 year spot beta values have been broadly stable over this timeframe (the 10 year betas increase slowly whilst the 5 year betas have been

[70] Annex 8, Oxera, RIIO-ED2 balance of risks, prepared for the ENA, 22 August 2022
[71] "*Cadent Gas Limited, National Grid Electricity Transmission plc, National Grid Gas plc, Northern Gas Networks Limited, Scottish Hydro Electric Transmission plc, Southern Gas Networks plc and Scotland Gas Networks plc, SP Transmission plc, Wales & West Utilities Limited vs the Gas and Electricity Markets Authority*" CMA Final determination Volume 2A: "*Joined Grounds: Cost of equity*", 28 October 2021, paragraph 5.338
[72] Annex 7, Frontier Economics, Cost of Equity – Response to RIIO ED2 Draft Determinations, a report prepared for WPD, 23 August 2022
[73] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022, Figures 4.1, 4.2 and 4.3

falling slowly), but the 2 year betas which were previously at a higher level than the 5 year and 10 year betas have shown a noticeable reduction in the most recent five months. Larger variations are generally observed in beta estimates based on shorter sample lengths and this makes interpretation of these values more difficult and less reliable, as material changes in a short timescale is highly unlikely to reflect a true under-lying change in the systematic risk of the relevant companies. This perhaps helps to explain why the full set of beta data previously considered by Ofgem in RIIO-GD2 didn't only look at spot values for different sample lengths, but also averages of these beta values across 2 years, 5 years and 10 years.

Thus, the data does not support any significant change in assumed beta values since RIIO-GD2/T2.

In their new data update report using data up to June 2022, Frontier consider it appropriate to slightly decrease their previous range for the unlevered beta compared to their earlier (November 2021) report by 0.01, to 0.30-0.33, with a new midpoint at 0.315. This is still slightly higher than Ofgem's value of 0.311 from the December 2020 RIIO-T2/GD2 Final Determination and included again in the RIO-ED2 draft determination[74]. Frontier's updated data does not show a significant difference from their November 2021 table for most of the estimates, and this new range reflects most of the data points in Frontier's table. Frontier recognise that lower values are indicated by the most recent short-term data points than in their November 2021 report (especially the 2 year spot beta values), but caution against putting too much weight on these, as they are likely to be driven by the recent bear market caused by the war in Ukraine which, like values affected by the Global Financial Crisis and dotcom periods in previous periods, should be interpreted with caution due to the short-term flight to safety effect in these market conditions. As Frontier note "*If we simply take the lower beta at face value, but do not increase the estimation of the expected equity return (which is true in the short term volatile market), then we would produce perverse results where the cost of equity for utilities decreases in volatile markets, which clearly is implausible*."

In conclusion, the equity beta value (for an assumed notional gearing of 60%) should be no lower than the 0.759 used in RIIO-T2/GD2, and the mid-point of our updated range from 0.73 to 0.80 is slightly higher than this, at 0.765[75] – although as noted above, there have been increases in risk (see FQ7 above) that are not yet reflected in the data from which these beta values are calculated and so these should instead be taken into account when choosing a point value within the range.

[74] Annex 7, Frontier Economics, Cost of Equity – Response to RIIO ED2 Draft Determinations, a report prepared for WPD, 23 August 2022, Section 4, pages 20 and 21
[75] Ibid

Step 2 - implied cost of equity consultation questions

FQ10. Do you agree with our interpretation of the cross-check evidence?
We agree with the following high level comments on the use of cross-checks which were made by the CMA in the 2021 Energy Licence Modification Appeals at paragraph 5.718: *"In coming to our overall assessment of GEMA's use of cross-checks, we highlight three key points:* *a) The CAPM is an imperfect and imprecise tool – but that it is broadly regarded as the best model on which to base an estimate of the cost of equity for a regulatory price control.* *b) No cross-checks, be it those used by GEMA or the alternatives suggested by the appellants, are perfect. Neither is it always possible or desirable to accurately rank and/or weight potential cross-checks, as effectiveness can depend on the situation to which they are applied.* *c) We consider that the most appropriate role for cross-checks is to use them to assess whether a CAPM-based estimate appears materially miscalibrated versus current market-based data. If any cross-check was disproportionately effective at identifying the 'correct' cost of equity, it would presumably replace the CAPM as the primary method of calculating the cost of equity and would no longer be considered a cross-check."* The increase in the COE in the DD relative to Ofgem's working assumption of 4.65% and the RIIO-T2 / GD2 outcome of 4.55% is entirely due to updates in the risk free rate and reflects increases in market interest rates (albeit only to April 2022, further increases having taken place since then), partially offset by a small reduction in the RPI-CPI(H) wedge used). Other than the Modigliani-Miller cross-check (which as explained in response to question FQ12 below isn't really a cross-check of the CAPM estimate at all), Ofgem's cross-checks are based on comparators which have different risk from regulated networks or are based on short term market values, where such values may be volatile and in some cases there may be broad ranges of values. Furthermore, most of Ofgem's cross checks, even those based on short-term and potentially volatile data, are not based on values from within the past few months, and so cannot reflect latest market data and views. Weight should not be placed on cross-checks which are based on short-term, hard-to-interpret and potentially volatile values, but this is even more the case where such cross-checks use data that may be out-of-date. Even since February there have been significant changes in market conditions and in the wider geopolitical environment, where these changes will put upwards pressure on required returns which will not be reflected in the cross-check data presented in the Draft Determination. For this reason care needs to be taken in the interpretation of the Ofgem's cross-check evidence. In addition, the overall impression created by the values in Ofgem's Table 18 is misleading – certain of Ofgem's checks are unreliable and imprecise, values for others are too low (and more representative values would be higher), and other cross-checks (e.g. ARP-DRP, which now – even more clearly than at the time of RIIO-T2/GD2 - shows the CoE should be higher) are missing. More detailed comments on the individual cross-checks and on other useful cross-checks that are missing from Ofgem's table are included in the answers to questions FQ11 to FQ13 below, but the following table summarises some of this information in very abbreviated form to show how Ofgem's DD Table 18 does not give a balanced overview of the available cross-check information. Instead, contrary to Ofgem's view at paragraph 3.83 of the consultation that "*cross-checks support values in the lower*

half of the CAPM range" the converse is true, and so if weight was to be attached to cross-checks they would on balance support use of a higher cost of equity.

Even so, consistent with the views of the CMA in the 2021 Energy Licence Modification Appeals at paragraph 5.718(c) that was reproduced above, we consider that *"the most appropriate role for cross-checks is to use them to assess whether a CAPM-based estimate appears materially miscalibrated versus current market-based data."* The available cross-check evidence, as summarised in the Table below, does not suggest that the CAPM evidence is "materially miscalibrated", and so the 'Step 2' cross-checks should not be used to modify the CAPM estimate of the cost of equity (although if any such Step 2 change was to be made, it should be an upwards adjustment to the cost of equity, rather than a reduction). Instead, the CAPM estimate should be used.

Cross-check	**Cost of Equity (from Ofgem's DD Table 18)**	**WPD views of CoE value**	**Comments**
Modigliani Miller cost of equity inference	3.4% to 4.7%	The true range of values using Ofgem's MM cost of equity inference approach is both wider and higher, particularly at the top of the range (see FQ12 below)	Ofgem's range is not a reflection of Ofgem's beta and gearing values, for different sample lengths and averaging periods, but reflects just 2 data points for each of 4 companies (SSE being excluded) which happen to give low estimates, rather than the actual range of 22 beta estimates for each company in Ofgem draft determination Table 32. The true range using Ofgem's MM cross-check approach and the full set of Ofgem's own data (see Table 32 in the Draft Determination) is actually much wider, even if the SSE values aren't used (and the top end of the range would be very much higher if SSE values are included). The MM cross-check results also need updating for more-up-to-date revised estimates of RFR and TMR (see questions FQ2 to FQ6 above), which will further raise the CoE estimates found using this so-called cross-check.
MAR implied cost of equity	3.2% to 3.9%	N/A	As explained below, evidence suggests no correlation between the MAR and returns. Limited weight (if any) should be given to this cross check. In any case, the range presented here for the "Equity inferences from MAR transactions" appears to be taken from Table 16 in the consultation, based on just 4 transactions. As explained in FQ11 below, the figure derived from the WPD transaction can be very easily changed from 3.8% to 4.83%. Similar factors may also mean that the values from the other 3 transactions are likely to be underestimated, and 2 of the 4 transactions are in water, where risks are lower and so a correspondingly lower cost of equity is to be expected.
Unadjusted OFTO implied cost of equity	4.4%	4.4% to 5.4% (or to 7.7%)	This cross-check is of limited relevance given the differences in risk between

			post-construction OFTO investments and regulated networks. The suggested range shown adds an estimate – based on Ofgem data, published 31/3/22 – for the construction period to create the range shown, but risks are still not comparable. Values are not adjusted for gearing.
Adjusted OFTO implied cost of equity	3.1%	3.1% to 10.12% (or 12.84%)	As above, adds an estimate – based on Ofgem data published 31/3/22 – for the construction period to create the range shown. This cross-check is even less relevant than the unadjusted OFTO implied CoE figure in the row above: differences in gearing can no longer partly offset the differences in risk.
Unadjusted investment managers' TMR cost of equity	5.1%	6.0%	Likely to be downwards biased given the FCA regulatory framework; are the subjective views of certain organisations chosen by Ofgem; can be seen to be volatile; should adopt a higher uplift from the source geometric values (1.87% instead of 1%), lifting the estimate from 5.1% to 6.0%
[Unadjusted?] infrastructure fund implied equity IRR	4.2%	>4.2% to 5.2%	The information is of limited relevance, is unreliable, and does not give a meaningful cross-check of the required cost of equity for a regulated energy network. The investments of the infrastructure funds do not have a risk equivalent to that of RIIO network. Adjustments previously made by Ofgem to published values were not robust. There is also a lack of consistency between the funds' own betas and CoE (discount rate) which suggests that this data is unreliable for the type of cross-check attempted by Ofgem. There is also some evidence that the funds themselves see themselves as lower risk than regulated networks (with a 1% or greater difference indicated)
CAPM with 0.9 equity beta and investment managers' TMR	4.5%	5.4%	See comments above on the unadjusted investment managers' TMR cost of equity
ARP – DRP	Not used	Shows the CoE proposed in the DD is too low	An updated application of the ARP-DRP approach using recent ILG and debt market yields now shows even more clearly than previously that the CoE proposed in the DD is too low.
DGM	Not used	4.6% to 9.4% Shows the CoE proposed in the DD is too low	Recent estimates for UK listed utilities using a range of growth rate estimates show that the DGM implied cost of equity is between 4.6% and 9.4%,

			with just one value for one company below 5.1%. Crucially, in order to imply an average cost of equity equal to Ofgem's DD value of 4.75%, long term real dividend growth would need to be negative for 4 of the 5 UK listed utilities, between -0.29% and -1.29%, which is not plausible.
Long-term profitability	Not used	Shows the CoE proposed in the DD is too low	Market-wide profitability has not fallen with the falling interest rates in recent years and suggests that the allowed return on equity of 4.75% proposed by Ofgem for ED2 can safely be regarded as not too high.

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

MAR cross check

In this response we explain for the MARs cross check:

- Why, in principle, undue weight should not be attached to MARs data
- That new evidence demonstrates no correlation between allowed return and MARs
- New evidence demonstrates that, despite MARs being greater than 1, networks are not overvalued
- Why Ofgem's updated MARs cross checks are flawed

Limited, if any, weight should be applied to a MARs cross check. From an economic principles perspective, regulated networks invest for the long term and, to ensure finance can be secured for those investments, investors have to be confident in the strength and stability of the regulatory regime.

Placing undue reliance on a MARs cross check means Ofgem is placing reliance on short term market data. To do so would be an error. Recent MAR data may well suggest ratios of more than 1 but these values could fall, particularly if undue weight is attached to them. As explained by Frontier Economics[76], "Ofgem would face legitimacy challenges if and when high valuation conditions reverse. For example, when the economy is in a recession and MAR is lower than 1, through no fault of the price control settlement, these policies would imply the opposite results putting upward pressure on the implied cost of equity in an environment where Ofgem may find it less justifiable to increase the allowed returns."

Similarly Oxera explain that, in a competitive market, company valuations do not determine the equilibrium price of a product and so should not mechanistically lead to lower allowed returns[77].

Central to the use by Ofgem of MARs as a cross check for allowed returns is the assertion that, after allowing for sustainable growth, MARs must be explained by

[76] Annex 10, Frontier Economics, RIIO-ED2 Cost of Equity Cross-checks, prepared for the ENA, 22 August 2022, page 8
[77] Annex 12, Oxera, Market-to-asset ratios as a cost of equity cross check, prepared for the ENA, 22 August 2022, section 3A

excess returns, either in the form of the allowed return being higher than required or from anticipated outperformance[78].

Precisely why companies have been transacted at MARs above 1 is unknown but Oxera present compelling evidence in their report to demonstrate there is no clear correlation either between MARs and a measure of the generosity of allowed returns, or of MARs and achieved RORE[79]. If there is no evidence of correlation the link between MARs and returns relied on by Ofgem cannot be robust and cannot be relied upon.

Drawing out a few observations from Oxera's evidence, they find:

- No correlation between traded MARs and a measure of headroom in the allowed risk free rate
- No correlation between traded MARs and RORE
- Transaction MARs consistently above 1 and insensitive to regulatory determinations

We recognise the CMA agreed with Ofgem's interpretation of MARs evidence in the RIIO-T2/GD2 appeal but note that the evidence now presented was not available at that time and, had it been, the CMA may have taken a different view.

What Oxera do observe is that MARs are sticky. They explain that, like some other asset classes, the value of the business is significantly determined by a judgement on the exit value or terminal value and based less on the cash flows received during ownership. This makes sense as the cash flows received during a given price control are relatively low given the 45 year asset lives used and application of a real allowed return rather than nominal.

They further note that it is logical for networks to assume an exit or terminal MAR greater than 1 if they have observed such values over a prolonged period of time. There is no need to backsolve that terminal value into assumptions of performance and return, the value is a judgement on an unknown and unknowable number. Given that network sales are generally at the behest of the current owner and that they can choose whether or not to sell, such an approach is entirely logical and further undermines the argument that the MAR reveals significant information.

As with the evidence on the lack of correlation between returns and MAR, the importance and focus on terminal value is new evidence not previously considered by the CMA.

If anything, a MAR above 1 is evidence that investors have confidence in the regulatory regime. The loss of that confidence would likely reduce MARs below 1 and be highly detrimental to consumers as it would be accompanied by investors choosing not to invest in the regime, to not provide the capital required for investment, and so put at risk Net Zero. If lost, it may take many years, and considerable increases in the WACC to restore investor confidence.

Further new evidence can be found in the report from Frontier Economics[80]. They demonstrate that, based on commonly used valuation metrics, contrary to Ofgem's conclusions based on MAR analysis, the valuation of network businesses is not high

[78] Ofgem, RIIO-ED2 Draft Determinations, Finance annex, para 3.66
[79] Annex 12, Oxera, Market-to-asset ratios as a cost of equity cross check, prepared for the ENA, 22 August 2022, sections 2B and 2C
[80] Annex 10, Frontier Economics, RIIO-ED2 Cost of Equity Cross-checks, prepared for the ENA, 23 August 2022, section 2.3

relative to the market. If anything, once short term market noise is adjusted for, networks are valued at the lower end of the range.

Ofgem has chosen to provide additional data points based on recent transactions, including the National Grid acquisition of WPD, and a new inference model.

The new inference model is based on a Dividend Growth Model (DGM) approach yet Ofgem chooses not to place any weight on DGM cross checks. In the RIIO-T2/GD2 CMA appeal for example Ofgem dismissed DGM models because they are highly subjective[81]. It must surely be an error to exclude the broader evidence of DGM cross checks and to criticise such approaches while simultaneously attaching weight to a MARs cross check based on DGM principles.

We further note with Ofgem's inference model that is highly sensitive to the assumptions used. National Grid has previously explained that the acquisition of WPD represented a strategic pivot and that three transactions were considered as a package in terms of valuation. The transaction to purchase WPD was not an isolated transaction and included a linked sale to PPL (the owners of WPD) of Rhode Island for a substantial premium. The sale of National Grid Gas was announced at the same time and also factored into the valuation process. Factoring in the premia from just the Rhode Island sale would reduce the MAR to 1.40. Combining that with a growth rate of 3% p.a. (which is similar to that implied by the ED2 Draft Determinations and which should be higher once the increases to totex suggested by other responses to this consultation are taken into consideration) would infer a return of 4.83%, some 18bps higher than the 4.65% used by Ofgem which, itself, is likely to be an underestimate of investor expectations at the time.

To summarise, new evidence demonstrates there is no evidence of any correlation between MARs and returns. By contrast, there is evidence that MARs are 'sticky' and that networks are not overvalued relative to the market. Ofgem rejects the use of a Dividend Growth Model cross check as being too subjective but applies DGM principles in developing the MAR inference model. As explained in this response, to place significant weight on MARs evidence is wrong in principle and could also put Ofgem in a position where it could have to increase returns in the event MARs fell below 1 for reasons that had nothing to do with the price control settlement.

<u>OFTO cross check</u>

In short, the information which Ofgem give in the DD on OFTO returns should not be used to inform the required returns for the onshore regulated distribution networks for reasons which include (i) the risks associated with OFTO assets are not comparable to those faced by onshore networks and (ii) Ofgem's OFTO data relates only to the operational period and ignores the higher risks that are typically faced during construction.

It has long been recognised that OFTOs face materially lower risk than networks, not least because they have no construction risk but also because the nature of the regulatory/commercial framework is such that their operational activities are lower risk even than just the operational activities of the regulated networks. The reasons for this include the lack of regulatory reset risk until the end of the 20 or 25 year term of the Tender Revenue Stream instead of after every 5 years; and an absence of

[81] See for example, The CMA's RIIO-T2/GD2 Appeal Final Determination, paragraph 5.657(a) - "*GEMA also submitted in relation to the cross-checks that it had chosen not to use in its determination. GEMA submitted that: The DDM and DGM suggested by the appellants had been considered, but were dismissed by GEMA as they are highly subjective*."

political risk. Other factors to consider are that OFTOs own assets with no construction risk and which have significantly greater cashflow visibility achieved through a project finance structure with a wide range of de-risking contractual mechanisms which do not apply to RIIO networks[82]; OFTOs benefit from additional mechanisms associated with risk transfers and project de-risking[83]; as well as having a different risk structure from onshore networks, interpreting OFTO returns is complicated by their different financing parameters, tax structures and other data uncertainties[84]; and the equity IRR estimated from OFTO is likely to understate the expected return given potential cost outperformance, tax, and financing outperformance over the operational life[85].

The difference in risk for OFTO assets during construction and operation is very significant. Onshore energy networks will also see differences in risk at different phases of the project life cycle and for different types and generations of assets, though the delineation of these different phases and categories is not straightforward and probably not feasible. Ofgem have published IDC estimates for the construction period of offshore transmission assets: these figures show materially higher financing costs and cost of equity during the construction period. For example, Ofgem's latest figures published at the end of March 2022 gives the asset beta range for offshore transmission assuming a debt beta of zero as 0.45 to 0.75, with a point estimate of 0.6, which would imply a real CoE of 10.12% (and range from 7.4% to 12.84%) using the RIIO-ED2 DD values of RFR and TMR and notional gearing (60%) – although it can't be assumed that offshore developers necessarily agree that these values reflect the true risks during this phase of the project: in comparison, the asset beta range in the RIIO-ED2 DD is given as 0.323 to 0.373 (see RIIO-ED2 Draft Determination Finance Annex Table 11), which is equivalent to 0.285 to 0.335 if restated assuming a zero debt beta to make it comparable to Ofgem's figure for offshore transmission.

From this it is clear that Ofgem themselves appreciate that financing costs are different during construction and operational phases, yet choose to use only the lower figure for the operational period as the offshore transmission cross-check, and ignore the much higher figure during the construction period. Given the scale of investment that is expected in RIIO-ED2 (aggregate RAV additions across the 5 years are typically 40% to 50% of the average RAV, see RIIO-ED2 Draft Determination Finance Annex Appendix 8), the comparisons of the OFTO cost of equity in the RIIO-ED2 DD Finance Annex at paragraphs 3.71 to 3.75 and in Appendix 5 - even when gearing adjusted - to the required cost of equity on regulated network assets are both inappropriate and misleading.

Ofgem has itself previously identified that the unadjusted OFTO cross check of 4.4% is of limited value given the lower risk nature of the investment, but has previously also highlighted the higher gearing of OFTOs as a compensating consideration[86]. The gearing adjusted return of 3.1% has no such compensating adjustment and is just plainly irrelevant as a comparator.

Other problems with the comparison have previously been raised with Ofgem but are still being ignored. For example, there is the impact of the residual or "terminal" value at the end of the initial tender stream, which will also be reflected in the bids made for OFTO assets but are not factored into Ofgem's analysis. Even a relatively

[82] "*Cadent Gas Limited, National Grid Electricity Transmission plc, National Grid Gas plc, Northern Gas Networks Limited, Scottish Hydro Electric Transmission plc, Southern Gas Networks plc and Scotland Gas Networks plc, SP Transmission plc, Wales & West Utilities Limited vs the Gas and Electricity Markets Authority: Final determination*", CMA October 2021, paragraph 5.632(a)
[83] *Ibid*, paragraph 5.632(c)
[84] *Ibid*, paragraph 5.632(d)
[85] *Ibid*, paragraph 5.632(e)
[86] See for example RIIO-ED2 Draft Determination Finance Annex paragraph 3.74; and the CMA's RIIO-T2/GD2 Appeal Final Determination at paragraphs 5.650, 5.632b and 5.638

modest assumed terminal value would have a material impact on the eventual level of return on equity on these projects. Whilst Ofgem recognise this issue at paragraph 3.73, its impact is not taken into account in the cross check. There is no basis to assume that bidders for OFTO assets do not take into account the potential for revenue streams after the initial TRS. We also note that in 2021 Ofgem consulted on arrangements for the end of the Tender Revenue Stream for OFTOs, and that consultation responses show that this is a material issue on many projects[87], both of which confirm that this factor would need to be factored into any comparison. In summary, Ofgem's comparison of OFTO returns and required equity returns on network assets, even using the updated cross-check inference model, do not take account of certain factors which would have a material impact on the implied results, but even if these were built into the comparison it would still be of minimal informational value given the inherent difference in nature of and risks faced by the offshore transmission links and the complex onshore networks. In fact, the new approach set out at Appendix 5 is in some respects worse than the previous simple comparison of headline equity returns on OFTOs and regulated networks. It was at least clear that under the earlier approach the figures were not directly comparable, but the new approach confuses the issue by manipulating the OFTO returns and restating them at a lower gearing, but without being able to compensate for the inherent differences in risk. Thus, the numbers are still not comparable, but if this is not appreciated by the reader they may inadvertently attach undeserved weight to the OFTO return figure presented by Ofgem. In any case, if 'gearing adjusted' return information for offshore transmission is to be included in a table of 'comparator' cross-check values, it should not show the return for the operational period only, but should also show the higher required equity return during construction. As explained above, rather than a figure of 3.1%, this would give a range of values from 3.1% to 10.12% (or 12.84%) – though the upper end of this range would be higher if the upwards corrections to RFR and TMR that were described in the answers to questions FQ2 to FQ6 above were also taken into account.
FQ12. Do you agree with the cross-checks we have used and are there other cross-checks we should consider?
Ofgem's cross-checks are summarised in Table 18, reproduced below:

[87] See e.g. the Transmission Capital Partners response to Ofgem's consultation "*Offshore Transmission Owner (OFTO) End of Tender Revenue Stream – Consultation concerning policy development*", e.g. page 1 paragraphs 3 and 4, and on page 5 the response to question 11, [Offshore Transmission Owner (OFTO) End of Tender Revenue Stream – Consultation concerning policy development | Ofgem]

Table 18: Summary evidence on cross-checks

Cross-check	Nominal	CPIH-real	Source
Modigliani-Miller cost of equity inference (WACC cross-check)	5.5% to 6.8%	3.4% to 4.7%	Real values as per Table 14 for NG, PNN, SVT and UU. Nominal values derived using 2% CPIH assumption, for example: (1+3.4%) * (1+2%) – 1 = 5.5%
MAR-implied cost of equity	5.3% to 6.0%	3.2% to 3.9%	Real values as per Table 16. Nominal values derived using 2% CPIH assumption
Unadjusted OFTO implied equity IRR	6.5%	4.4%	Nominal value as per Figure 3 CPIH-real derived using 2% CPIH assumption. (1+6.5%) / (1+2%) – 1 = 4.4%
Adjusted OFTO implied cost of equity	5.2%	3.1%	Real value derived in Appendix 5. Nominal value derived using 2% CPIH assumption
Unadjusted investment managers' (TMR) cost of equity	7.2%	5.1%	Nominal value as per Table 17. Real derived using 2% CPIH assumption.
Unadjusted infrastructure fund implied equity IRR	6.3%	4.2%	Nominal value as displayed in Figure 4. Real derived using 2% CPIH assumption.
CAPM with 0.9 equity beta and investment managers' TMR	6.6%	4.5%	Real value calculated using risk-free rate of -0.74% and real TMR of 5.1%. Nominal value derived using 2% CPIH assumption.

Source: Ofgem analysis

Each of these is considered in turn below.

MM cross check (WACC cross-check)

This isn't really a cross-check of the CAPM cost of equity at the chosen notional gearing at all: it is first an alternative calculation of the CAPM cost of equity at a different level of gearing, from which it then calculates a CoE at 60% notional gearing assuming the Vanilla WACC does not change at all with gearing. However, given the strict assumptions that must hold for the MM theorem of constant WACC to hold, it should not be a surprise if the calculated WACC at a company's actual gearing is slightly different from that calculated at the chosen notional gearing. The results of this cross-check cannot therefore provide any evidence to suggest that the CAPM estimate of the cost of equity at the chosen notional gearing should be reduced.

Furthermore, to the extent that the CAPM parameters are themselves underestimated, this cross-check is necessarily flawed as it is self-referential, i.e. it relies on these same flawed parameter estimates as the CAPM estimate which it purports to check.

Moreover, it appears that the main reason why in Ofgem's application in the RIIO-ED2 DD this so-called cross-check appears to support lower values of cost of equity than the CAPM estimate in Step 1 is because Ofgem have selected particular parameter values for beta and gearing which in some cases (notably for SVT and UU) are outliers and which consequently push the results of the MM cross-check down to an unjustifiably low value. Ofgem should instead have used values for these parameters that are representative of the wider set of values in the DD Tables 29 and 31 which Ofgem took into account when making the CAPM estimate. Once this change is made, the residual difference between the results of this MM cross-check and the primary estimate of the cost of equity found using CAPM would be very small, as Oxera have previously demonstrated[88] (typically 0.01% to 0.04% on the WACC, equivalent to 0.025% to 0.08% on the allowed cost of equity at a notional gearing of 60%).

This can be explained more fully as follows. Firstly, Ofgem's chosen parameters for this cross-check use an actual gearing level based on market value of debt (MVD) instead of book value of debt (BVD). Although Ofgem defended the use of betas based on MVD as well as BVD in the RIIO-T2/GD2 appeal on the grounds that the choice made little difference[89], this is not generally the case – unless, correctly but contrary to Ofgem's approach, when using the MVD values a consistent basis for valuing debt is also used when estimating gearing for the notional company as when calculating the gearing of the actual company.

For example, considering Ofgem's results when applying the cross-check to National Grid, merely replacing the gearing values based on MVD that were used by Ofgem with Ofgem's own figures based on BVD[90] would increase the implied CoE at 60% notional gearing from 4.6% for 5 yr spot and 4.4% for 10 year spot to 4.9% and 4.6% respectively. Alternatively, if MVD data is to be used, the debt of the notional company should also and consistently be expressed on an MVD basis[91]. The corresponding values of the implied CoE using the equivalent data points for NG would then be 5.2% and 4.9% respectively, where these calculated CoEs would still relate to an amount of notional equity that is equal to 40% of the RAV.

Secondly, Ofgem's MM cross-check range is based only on using 5 year spot and 10 year spot beta estimates, but these values are not representative of the full range of beta evidence that is considered by Ofgem (see Table 32), particularly for SVT and UU. Thus, a large part of the difference between the results of this cross-check as presented by Ofgem and the main CAPM cost of equity estimate from Step 1 are, in effect, because this cross-check uses different, and lower, beta values instead of the overall beta estimate used by Ofgem in Step 1 which was based on a wider range of evidence. For example – if you used BVD instead of MVD for gearing, and 5 yr window 5 yr average values of beta (instead of 5 year window spot values), with Ofgem's values for other parameters, the SVT and UU WACC would each increase to 2.2% (from 1.8% and 1.9% respectively) and the implied COE at 60% notional gearing would increase from 3.4% and 3.5% to 4.5% and 4.5%.

Thus, whilst the results of the cross-check – excluding those for SSE, which are much higher - are presented by Ofgem as a range from 3.4% to 4.7% (paragraph 3.59), both the top and bottom of the range are too low, most of the possible alternative data points based on Ofgem's raw equity beta table (table 31) would be in the higher parts of the range, and if more weight is given to the values based on NG (as when estimating beta for Step 1) the cross-check would not justifiably support a reduction to the Step 1 (CAPM) estimate of the cost of equity.

In addition, ILG yields have increased materially since the end of April (which was the basis of Ofgem's RFR value) – if you merely update the RFR using the 20 year ILG yield as at 30/6/22, the RFR, and thus implied CoE using the MM cross-check would

[88] See Table A1.2 in "The cost of equity for RIIO-ED2: prepared for Energy Networks Association, a report commissioned on behalf of the Distribution Network Operators", Oxera, 4 June 2021
[89] The CMA's RIIO-T2/GD2 Appeal Final Determination, paragraph 5.523
[90] See the RIIO-ED2 Draft Determination Finance Annex, Table 32
[91] This point was previously recognised by CEPA in a report written for Ofgem: "RIIO-2: Use of Market Evidence", 9 July 2020, page 36: "*The same principles that might cause the market value of actual company debt to deviate from its book value would also cause the market value of notional debt to deviate from its book value. This means that for consistency if we de-lever using a market value of debt, we should re-lever using an adjusted notional value of debt*."

be noticeably higher, and so both the top and bottom of the range implied by this cross-check would be increased by c.0.2% (although as explained in our answers to FQ2 to FQ3, once other evidence for RFR is considered the increase in RfR and thus implied CoE from this cross-check would be much bigger).

The MM cross-check also depends on appropriate values being used for both RFR and TMR. These should both be increased, and not just because of changes in market rates since April (as explained in the answers to FQ2 to FQ6 above). The results of the MM cross-check would then further increase correspondingly as a result.

<u>MAR implied cost of equity</u>

Please see the response to FQ11 for our views on the MARs cross check. Limited weight should be attached to this cross check. Ofgem's reliance on it is based on a belief that MARs must reveal something about returns yet new evidence presented demonstrates that MAR expectations are 'sticky', that there is no correlation between returns and MARs, and that despite MARs greater than 1, networks are, if anything, undervalued compared to other large businesses.

<u>Unadjusted OFTO implied equity IRR</u>

OFTO internal rates of return (IRRs) are an unreliable comparator, as OFTOs are a lower risk investment than an onshore electricity network, for reasons that were noted in the response to FQ11 above. This is in part recognised in the RIIO-ED2 DD Finance Annex at paragraph 3.74. Ofgem suggest that although the unadjusted equity IRRs may relate to a lower risk asset, the financial risk is higher (as gearing levels are higher). Even if this were true, it does not enable the unadjusted OFTO implied equity IRR to be used as a useful cross-check of the proposed RIIO-ED2 cost of equity, as the significant difference in risks make any such use of the OFTO information completely subjective.

For this reason, the unadjusted OFTO returns cannot give any real insight into whether the proposed RIIO-ED2 cost of equity is set at an appropriate level. Consistent with this, the CMA similarly found that the interpretation of this cross-check should be broad in nature[92].

In addition, since the CMA determination, it has come to our attention that there is public information that shows that the terminal value assumptions are important for OFTO bidders and should not have been disregarded by Ofgem or the CMA[93]. This information, which appears to be at odds with the evidence previously presented by Ofgem[94], further calls into question Ofgem's use of this OFTO data as a cross-check without making an upwards adjustment in recognition of this issue.

<u>Adjusted OFTO implied equity IRR</u>

[92] See CMA's RIIO-T2/GD2 Final Determination at paragraph 5.689
[93] Offshore Transmission Owner (OFTO) End of Tender Revenue Stream – Consultation concerning policy development | Ofgem: see Transmission Capital Partners consultation response, pages 1 and 5: "*When bidding the competitive revenue streams for the initial revenue period for its OFTOs assets, TCP placed considerable importance to the fact that it was the owner of the transmission assets and would benefit from transmission life extensions should the generation assets extend beyond their original stated life expectations*." and "*… Whilst the majority of the notional OFTO regulated asset base would be amortised during the initial revenue period, the TRS level during the initial revenue period reflects the terminal value assumptions adopted by OFTO bidders and, in the case of TCP, transparently disclosed in all of its bids*."
[94] See CMA's RIIO-T2/GD2 Final Determination at paragraph 5.649

Ofgem now present, in Appendix 5 of the draft determination, new analysis of the OFTO equity return information which attempts to make them "*more comparable with a cost of equity at 60% notional gearing*." Some of the limitations of this analysis were explained above in our response to question FQ11. These include the significantly lower risk profile associated with OFTO asset ownership compared to onshore electricity network ownership, which means that, like the unadjusted OFTO implied equity IRR cross-check, the Adjusted OFTO implied equity IRR is unsuitable for use as a cross check. Indeed, the adjusted equity IRR as a cross-check would be worse and more misleading than the use of the unadjusted OFTO returns, as the differences in asset risk between OFTOs and DNOs remain, but the gearing adjustment which Ofgem now makes has attempted to remove the impact of differences in financial risk, which in the unadjusted OFTO return cross-check would partially compensate for the differences in risk, as Ofgem have previously recognised[95].

In addition, as noted in the consultation at paragraph 3.73, Offshore Transmission Owner (OFTO) returns increase significantly when a terminal value is included in valuation models, but additional sources of value such as this have been ignored in Ofgem's new calculations of adjusted OFTO implied equity returns, casting further doubt on the relevance of the new values presented by Ofgem. As noted above, there is now public information that shows that the terminal value assumptions are important and so should not be disregarded, especially since this new information relates to one of the most successful bidders for OFTO projects which operates a significant proportion of the all the projects that have been awarded[96].

Unadjusted investment managers' (TMR) cost of equity

As a precursor, we note that the value included for this cross-check in the Draft Determination at Table 18, i.e. 5.1% (real), is higher than Ofgem's proposed cost of equity for RIIO-ED2, and so this "unadjusted infrastructure fund implied equity IRR" cross-check would not support a lower cost of equity than the initial primary CAPM estimate of the cost of equity.

In addition, there are a number of reasons why the information presented by Ofgem as unadjusted investment managers (TMR) cost of equity does not give accurate or reliable information that should be used as a cross-check of the Step 1 (CAPM) cost of equity for RIIO-ED2. These include:

- the evidence is likely to be downward-biased, as these estimates are used by investment managers to provide prudent estimates of future returns to existing or prospective clients: as Oxera have previously explained "*This is mainly a function of the regulatory framework, namely the FCA Conduct of Business Sourcebook, which states the maximum rates of return that financial services companies must use in their calculations when providing retail customers with projections of future benefits (it creates a ceiling)*"[97] and "*Firms are required to use rates of return in their projections that reflect the performance of the underlying investments, but the ceilings imposed by the*

[95] See for example CMA's RIIO-T2/GD2 Final Determination at paragraph 5.650, 5.632b and 5.638, and Ofgem's RIIO-ED2 Draft Determination Finance Annex at para 3.74

[96] Offshore Transmission Owner (OFTO) End of Tender Revenue Stream – Consultation concerning policy development | Ofgem: see Transmission Capital Partners consultation response, pages 1 and 5: "*When bidding the competitive revenue streams for the initial revenue period for its OFTOs assets, TCP placed considerable importance to the fact that it was the owner of the transmission assets and would benefit from transmission life extensions should the generation assets extend beyond their original stated life expectations*." and "*… Whilst the majority of the notional OFTO regulated asset base would be amortised during the initial revenue period, the TRS level during the initial revenue period reflects the terminal value assumptions adopted by OFTO bidders and, in the case of TCP, transparently disclosed in all of its bids*."

[97] "The cost of equity for RIIO-ED2: Prepared for Energy Networks Association - a report commissioned on behalf of the Distribution Network Operators", Oxera, 4 June 2021 , pages 60/61

FCA aim to prevent consumers being misled by inappropriately high rates"[98]. They therefore reflect the regulatory framework and the danger of overpromising on future returns or mis-selling;

- they are the subjective views of certain selected organisations, and the CMA has previously noted that caution should be exercised in interpreting forecasts made by market analysts: "*These estimates may also prove to be no more accurate than our own assessment, or may be specifically tailored to particular investors or house views rather than representing the cost of capital demanded by the average or marginal investor in the sector*."[99]
- the values can be seen to be volatile – of the 6 managers for which Ofgem give updated values, three give new values that are 1.5% to 2% higher than previously, two are little changed, and one has fallen by almost 2%. The size of these changes, and the observation that they are not even all in the same direction, casts further significant doubt over the consistency or reliability of this information and its suitability for use as a cross-check.
- This volatility also reveals that the information is, at best, merely short-term subjective views, rather than long-term objective information, yet only 2 of the values date from 2022, from January and February. Not only is one of these values a clear outlier when compared to the other values, but since February there have been significant changes in both global and UK financial markets (for example, 20 year index-linked gilt yields increased by over 1.4% from the end of February to the end of June), and in the stability of the geopolitical environment (not least related to the war in Ukraine) which would be expected to increase the required TMR that investors in equity markets require. Whilst these changes do not undermine the Step 1 TMR estimate, given that this is based on very long-run average data using timescales across which such fluctuations will average out, it casts significant doubt over the relevance of relatively short-term subjective views such as the investment manager forecasts which Ofgem presents here, especially where these were all developed within an earlier and very different environment.
- they appear to be based on estimates of geometric returns, and it is not clear that Ofgem have made an appropriate upwards adjustment to reflect this. It appears that Ofgem are applying a 1% uplift for this, as in the RIIO-T2/GD2 SSMD, as the older set of data points in Ofgem's table (those in the columns headed "May 2020", although they actually date from September 2017 to December 2019") look the same. This 1% figure is probably too low, as Oxera have previously explained, noting also that a larger value of 1.87% would be the estimate implied by DMS data.[100]
- We also note that at Paragraph 3.78, as part of the justification for using this data, Ofgem say the investment manager forecasts are stable – but the data presented can't actually support this claim: not only are there material changes in most of the forecasts that have been updated (as noted above), but the data involves updating just some of the forecasts at just 2 points in time (December 2019 vs late 2021/early 2022) and so doesn't show (i) whether in the intervening period forecasts were higher (as was the case for some forecasts[101]), nor (ii) whether newer forecasts - which, when published,

[98] Financial Conduct Authority (2017), 'Rates of return for FCA prescribed projections', p. 5.
[99] Competition and Markets Authority (2021), "*Water Redeterminations 2020: Choosing a point estimate for the Cost of Capital – Working Paper*", January, p. 22
[100] "The cost of equity for RIIO-ED2: Prepared for Energy Networks Association - a report commissioned on behalf of the Distribution Network Operators", Oxera, 4 June 2021, page 61
[101] See for example the response to the CMA's Provisional Findings in the PR19 Redetermination from the Energy Networks Association, paragraph 4.38(b)(iii), Energy Networks Association (publishing.service.gov.uk)

might reflect current market, macroeconomic and geopolitical conditions – will also be at a similar level.

We note that use of a larger and better justified uplift on the geometric returns would bring the median estimate from this data much closer to Ofgem's TMR midpoint, even before the expected downward bias in these investment manager forecasts (as described above) is taken into account. Thus this cross-check, if properly considered, would not support a reduction to the CAPM estimate of the cost of equity.

Unadjusted infrastructure fund implied equity IRR

We do not consider the infrastructure fund discount rates presented by Ofgem to give a meaningful cross-check of the required cost of equity for a regulated energy network:

- The investments of the infrastructure funds used by Ofgem do not, for a number of reasons, have a risk equivalent to that of RIIO networks.
- Ofgem's figures for infrastructure fund implied equity IRRs are described as "updated" analysis of earlier July 2020 figures, and so are presumably calculated using the same approach. We do not consider some of the adjustments made by Ofgem to be reliable.
- Oxera have previously demonstrated that a "*lack of consistency between their own betas/CoE suggest that this data is unreliable for the type of cross-check attempted by Ofgem, and that infrastructure funds' discount rates are not an appropriate benchmark for the CoE in RIIO-2*."[102]

We consider each of these points in turn below.

First, we consider that these infrastructure funds have a lower risk–return profile and are not a suitable cross-check on the RIIO-2 CoE.

- For example, some of the funds largely invest in holdings of Public Private Partnership / Private Finance Initiative projects. During the development of RIIO-T2/GD2 these were the kind of funds that were first used by Ofgem as a cross-check, and which (therefore) Ofgem presumably considered the most comparable to regulated networks. However, even for these funds, information that was previously referred to by Ofgem and has since been updated shows that these investments are recognised to have a lower risk profile than regulated energy networks, and as a result regulated energy networks need a return that is at least 1% higher (see e.g. RIIO-2 SSMD May 2019 Figure 15, which has since been updated by the original source as follows: 2020 BBGI Annual Results (bb-gi.com) slide 47).
- Other funds considered by Ofgem at Figure 4 in the consultation invest in other asset categories such as operating renewable energy assets, as previously shown by Oxera[103]. Even for a particular fund's portfolio which might appear at first to face greater revenue or volume risks than energy networks, these may be hedged by long-term or availability-based contracts and/or government subsidies—e.g. renewable obligation certificates (ROCs). What is clear is that the asset classes and the risk of the diversified portfolios differ significantly from those of a pure-play energy network business. For example, unlike regulated networks they are not subject to regulatory reset risk or political risk, and for this reason we consider that the infrastructure

[102] "The cost of equity for RIIO-ED2: prepared for Energy Networks Association, a report commissioned on behalf of the Distribution Network Operators", Oxera, 4 June 2021, page 58
[103] See Table A1.3 in "The cost of equity for RIIO-ED2: prepared for Energy Networks Association, a report commissioned on behalf of the Distribution Network Operators", Oxera, 4 June 2021

funds' discount rates are not an appropriate benchmark for the CoE in RIIO-ED2 due to the fundamental differences in the risk profile.

Ofgem's previous analysis of infrastructure funds from July 2020[104] took each fund's discount rate and then deflated it using the market premium to the latest reported net asset value (i.e. the fund share price divided by fund NAV per share). The resulting 'implied IRR' was then used as a cross-check to support Ofgem's CoE. We assume this adjustment has again been made by Ofgem in the data presented in the RIIO-ED2 Draft Determination, which is described as an update to the earlier analysis. However, as Oxera previously explained[105], Ofgem assumes that any premium above the net asset value (NAV) means that the fund is overestimating its own cost of capital. There are, however, multiple explanations for a market premium that do not rely on the overestimation of cost of capital. For example, the NAV reported by each fund may take a more prudent view of future cash flows relative to market expectations. Therefore, Ofgem's adjustment, which reduces the implied cost of equity figures presented, is not reliable or well justified.

In addition, Oxera explained another sense-check that can be applied to the funds' data. As they are publicly traded, each fund has an observable beta, and so using the RfR together with each fund's discount rate and beta, and assuming that the discount rate is equivalent to the fund's CoE, an implied TMR for each fund can be calculated as a cross-check on the reasonableness of this data. Oxera's results gave ranges for implied TMR's for each fund[106]. From this analysis, Oxera observed that the results gave an *"average implied real TMR of 18.0%, with high variation. This is so high as to be unreasonable. Although infrastructure funds may relay useful data in some cases, they are clearly inappropriate for a CoE cross-check for regulated UK energy firms. The implied TMR and lack of consistency between their own betas/CoE suggest that this data is unreliable for the type of cross-check attempted by Ofgem, and that infrastructure funds' discount rates are not an appropriate benchmark for the CoE in RIIO-2."*

The infrastructure funds information should therefore not be used in the Step-2 cross-checks because this involves deploying non-comparable data. As a minimum, though, Ofgem should make some adjustment for the higher risk of regulated networks, for example by adding at least the 1% difference indicated previously by BBGI. This would increase the implied equity return from this cross-check in the Draft Determination Table 18 from 4.2% to 5.2% on a CPIH real basis.

Lastly, we note that the data presented by Ofgem for this cross-check in Figure 4 of the draft determination appears to have not been updated since early 2021: as observed above in our comments on investment manager forecasts, since then there have been significant changes in market conditions and in the wider geopolitical environment (this being the case even since the end of April 2022), where these changes will put upwards pressure on required returns which will not be reflected in the data presented in the Draft Determination.

<u>CAPM with 0.9 equity beta and investment managers' TMR</u>

As this cross-check is based on the same underlying investment manager information as the unadjusted investment managers' (TMR) cost of equity discussed above, it suffers from the same deficiencies and so does not give a meaningful cross-check of

[104] " RIIO-2 Draft Determinations – Finance Annex", Ofgem, 9th July 2020, page 63
[105] "The cost of equity for RIIO-ED2: prepared for Energy Networks Association, a report commissioned on behalf of the Distribution Network Operators", Oxera, 4 June 2021, page 57
[106] Ibid Table A1.4

the Step 1 (CAPM) cost of equity for RIIO-ED2 (although we do note that in Table 18 of the Draft Determination, Ofgem's value using this cross-check, like that of the Unadjusted investment managers' (TMR) cost of equity, does not support a material reduction to the CAPM estimate of the cost of equity.

Other Cross-checks that should be considered

During the RIIO-2 price controls energy networks have proposed use of the "Asset Risk Premium – Debt Risk Premium", which uses debt market evidence, as a cross-check of the proposed cost of equity.

As Oxera previously explained "*The asset risk premium is the additional compensation over the RFR that investors require to invest in a company as a whole. This is the premium for equity risk assuming zero gearing, and should be higher than the risk premium on debt given the lower priority of equity relative to debt in terms of claims on cash flows. A risk premium on energy network assets would be expected to be greater than that on the investment-grade bonds that these companies issue*."[107]

The "Debt Risk Premium" above the RFR can be calculated using the yields on the iBoxx £ non-financials A and BBB 10+ index, adjusting them for the expected loss and the risk free rate.

The asset risk premium is the premium for risk for an equity security with zero gearing. As Oxera explained "*We would expect such a security to offer a higher risk premium than high-quality debt securities given the lower priority of equity relative to debt in the order of claims on cash flows and assets*."[108]

Ofgem and the CMA have recognised the logic and potential value of the ARP-DRP cross check that has been developed by Oxera[109], but in RIIO-T2/GD2 chose not to give it weight, albeit at that time DRP was notably less than ARP and so the conclusion that the proposed CoE was too low depended on the estimate of the margin by which the ARP should exceed the DRP[110]. Parameter values have since changed such that the ARP is now much closer to the DRP: Oxera's new report suggests that Ofgem's RIIO-ED2 draft determination parameters would indicate an ARP-DRP value of 0.93%[111], whereas at the time of the RIIO-T2/GD2 draft determinations the parameters indicated an ARP-DRP of c.1.84%[112] and for RIIO-ED1 it was 1.73%[113]. It is therefore now even clearer than previously that the CoE should

[107] "The cost of equity for RIIO-2: A review of the evidence prepared for Energy Networks Association", Oxera, 28 February 2018, Section 5.1

[108] "The cost of equity for RIIO-2: A review of the evidence prepared for Energy Networks Association", Oxera, 28 February 2018, Page 49

[109] For example, in the PR19 redetermination, the CMA said at paragraph 9.3186 "*The Oxera analysis is based on what seems like a logical principle: that for a regulated business with capped returns, the cost of equity used in the WACC should still be assumed to remain* ***sufficiently above*** *the current cost of debt to promote equity investment in the sector. We agree that this is* ***conceptually sensible****, …*" (emphasis added);
and in the ELMA Appeal FD the CMA noted at paragraph 5.717 that "*… while we accept that ARP-DRP might ultimately gain more general acceptance as a relevant cross-check within regulatory price control processes, the approach and its acceptance is inadequately developed at this stage to be sufficiently convincing evidence that GEMA's CAPM-based estimate is wrong. …*"

[110] This explains Ofgem's comment in the RIIO-ED2 draft determination at paragraph 3.91: "*We do not believe that the ARP-DRP results … is a valuable cross-check because it relies on regulatory precedents rather than contemporaneous market data*."

[111] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022, Table 5.1

[112] "Asset risk premium relative to debt risk premium", Oxera, prepared for Energy Networks Association, 4 September 2020, see e.g. Figure 3.4 and Table 3.1.

[113] Annex 15, Oxera, Cost of equity in RIIO-ED2 Draft Determinations, prepared for the ENA, 25 August 2022, Table 5.1

be higher, although the size of the increase needed is not revealed by the updated evidence referred to above alone.

Other cross-checks which do not rely on comparators which have different risk from regulated networks, or the subjective (and most likely conservative) views of certain investment advisors, or Ofgem's own subjective interpretation of MAR ratios, are available and should also be considered and taken into account.

- Dividend Growth Model (DGM) cross-check: The DGM is a well-established, forward-looking market-implied methodology that is used for valuation assessment or to estimate an implied cost of equity given market valuation. Ofgem itself recognises the merits of the DGM approach, but applies it only in an innovative and limited way when seeking to interpret MAR data through the new inference model for MARs rather than in the conventional and established form. It addition, this innovative use of DGM in relation to MARs "*still operates in the hypotheticals of the regulatory construct and therefore is not reconcilable to market share prices*."[114] The DGM should therefore be used instead in its conventional form to estimate the implied cost of equity, and in this form is a superior cross-check to Ofgem's MAR cross-check. This is in part because the DGM model does not require any prior belief or assumption to be made on what an appropriate or target cost of equity should be, whereas the approach adopted by Ofgem and other regulators to use the MAR requires a prior judgement of what an appropriate MAR value should be[115]. However, the DGM does require estimates of short and long-term dividend growth rates. Recent estimates for UK listed utilities by Frontier Economics[116], restated at 60% notional gearing and using a range of growth rate estimates, show that the DGM implied cost of equity is higher than Ofgem's proposed cost of equity in all scenarios, between 4.6% and 9.4%, with just one value for one company below 5.1%. Crucially, in order to imply an average cost of equity equal to Ofgem's DD value of 4.75%, the long term real dividend growth rate for 4 of the 5 listed UK utilities considered would need to be negative, between -0.29% and -1.29%, which is implausible given the levels of capital expenditure expected in the water and energy network sectors in the future. Frontier also showed that applying the approach to a peer group of European energy utilities gave higher figures for the cost of equity[117]. This DGM cross-check, which is more established and more reliable than Ofgem's, therefore provides further strong evidence that the 4.75% cost of equity proposed in the RIIO-ED2 draft determination is too low.
- Long-term profitability cross-check: As Frontier Economics explain, "*Ofgem should also introduce a cross-check on longer term profitability, as this would provide a way to move away from reliance on short run market evidence, which can be volatile and may send signals that prove to be ephemeral. To attract and retain capital, regulated businesses should have the opportunity to generate profits similar to comparable businesses (in terms of risk)*."[118] Ofgem does not set the returns that shareholders realise from holding an equity stake in a regulated business, as this also depends on the business's valuation which in turn depends on capital market conditions. Rather, when setting the cost of equity allowance, Ofgem is effectively setting the allowed level of profitability of the regulated business. While keeping CAPM evidence as the primary

[114] Annex 10, Frontier Economics, RIIO-ED2 Cost of Equity Cross-checks, prepared for the ENA, 23 August 2022, page 10
[115] *Ibid*, page 9
[116] *Ibid*, Figure 5
[117] *Ibid*, Figure 8
[118] *Ibid*, page 1

method, Ofgem should assess, as a cross-check, how the proposed level of allowed equity returns compares to the outturn level of profitability for comparable businesses, or even the market as a whole. This cross check provides, at a high level, a useful real-world check on whether or not the proposed allowed return for the regulated companies is reasonable Frontier Economics have considered this evidence in their recent report, which shows that market-wide profitability has not fallen with the falling interest rates over the past 20 years and suggests that "*the allowed return of 4.75% proposed by Ofgem for ED2 can safely be regarded as not too high*" and "*the allowed return determined by its [i.e. the regulators] primary method, the CAPM, is broadly in line with the real world*"[119]. Frontier do not propose that this cross-check should be used to set allowed returns, but it can be used as a cross-check of whether equity returns to networks are out of line with profitability in the wider market, and the evidence suggests they are not.

In conclusion, there are a range of additional cross-checks that Ofgem should have considered - ARP-DRP, DGM and a long-term profitability cross-checks – and all of these support a higher cost of equity than Ofgem has proposed in the Draft Determinations. This long response to question FQ12 has also provided comments on the cross-checks that Ofgem has proposed in the Draft Determination, and highlighted some of the limitations with each of these. These discussions and the implications for estimating the cost of equity in RIIO-ED2 were brought together in the response to question FQ10 above which concluded that a balanced consideration of cross checks does not support a cost of equity in the lower half of the range and, if anything, supports higher values.

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

The primary method of setting COE should continue to be CAPM, which is what the DDs do, with cross checks used as a sense check only. Given the concerns and limitations described in the response to questions FQ10 to FQ12 above it is clear that the cross checks should not be used to override the CAPM result. In addition, in their new report[120], Frontier Economics identify a number of additional drawbacks to placing reliance on cross-checks:

- *"No cross-check is perfectly robust or reliable, which is why they are not considered a replacement for CAPM as the primary estimation method of the cost of equity.*
- *All cross-checks will display some undesirable properties that markedly weaken their reliability.*
- *Use of short run measures would wash a combination of "market sentiment" and "noise" into the regulatory determinations, weakening stability and predictability and harming investor confidence. All of these measures would introduce a new form of pro-cyclicality into regulatory determinations, which runs counter to the original intention of the RAV-based model.*
- *Reliance on cross-checks introduces a new form of regulatory discretion into determinations, i.e. how to interpret noisy, volatile and potentially contradictory cross-check evidence.*
- *For all these reasons, UK regulators have always consciously avoided using such short-term market-implied evidence to set the allowed equity return.*

[119] *Ibid*, pages 19 and 20
[120] Annex 10, Frontier Economics, RIIO-ED2 Cost of Equity Cross-checks, prepared for the ENA, 23 August 2022, pages 1 and 2

- *We therefore recommend Ofgem to put less weight on short-term valuation based cross checks such as MAR analysis."*

It would also not be appropriate to adjust the individual CAPM parameters in the light of the cross-check evidence. This would result in a theoretically-unsound 'hybrid' estimate of the cost of equity that would be neither a CAPM result nor a cross-check estimate, and whose interpretation would consequently be problematic. Instead, the CAPM estimate should be based on the most relevant data that informs the individual CAPM parameters, as discussed in the answers to FQ2 to FQ9 above, and if any use was to be made of the cross-checks it should merely be as a "sense-check" of the high level reasonableness of the overall CAPM estimate. Attempting to 'fine-tune' the CAPM estimate on the basis of particular cross-checks would imply these cross-checks are capable of greater precision than is actually the case.

In any case, there is no case for downward adjustment to the Step 1 (CAPM) result based on Ofgem's Step 2 cross-checks, even in light of Ofgem's adjusted cross-check results, given the limitations, uncertainties and limited relevance of Ofgem's cross-checks that are explained above, as well as (in some cases) the need for Ofgem's values for particular cross-checks to be revised upwards. In fact, once these changes are made, and in light of the evidence from the alternative cross-checks identified above, the wider set of available cross-check evidence would instead suggest an upwards adjustment to the Step 1 result would be better justified.

Finally, it should be noted that in our response to question FQ15 below, we explain that it is important that Ofgem sets appropriate financial parameters and an allowed cost of equity which: reflect the balance between the significant risks of underinvestment compared to the marginal impact of setting the cost of capital too high; recognise the sources of (downside) risk asymmetry in the proposed price control; and ensure companies are financeable under a range of scenarios, and so in the final determination Ofgem should aim up to ensure an appropriate level of resilience in the sector. The wider set of cross-check evidence discussed above is relevant in this context too, and can be seen to lend further support to aiming up.

Step 3 - allowed return on equity consultation questions

FQ14. Do you agree that we should not adjust for expected outperformance when setting baseline allowed returns on equity?
Yes; as stated in our Business Plan, in the recent RIIO-2 appeals by the gas distribution and transmission companies the CMA found in favour of all appellants that the Gas and Electricity Markets Authority (GEMA) was wrong to impose the outperformance wedge, stating the following: "Our view is that GEMA has not demonstrated sufficiently why the extensive set of tools it used for RIIO-2 should be regarded as providing insufficient protection for customers"[121]. The CMA found errors in GEMA's analysis of the "extent to which operational outperformance in RIIO-2 should be probable", and stated that even if concerns about outperformance had been substantiated, 'the outperformance wedge would be a poorly designed mechanism to address these concerns"[122]. Further, the CMA also

[121] p.7, CMA, RIIO-2 Energy Licence Modification Appeals, Summary of final determination, Issued: 28 October 2021.
[122] p.7, CMA, RIIO-2 Energy Licence Modification Appeals, Summary of final determination, Issued: 28 October 2021.

recognised that the outperformance wedge "might undermine broader regulatory certainty which could result in increased costs to consumers over time"[123]. As a result, the CMA ordered that the decision to introduce the outperformance wedge should be quashed. We consider that the points made by the CMA are equally relevant to the RIIO-ED2 price control; even more so given the downwards asymmetry of the incentive package in the RIIO-ED2 draft determinations, the movement of baseline expenditure into uncertainty mechanisms, the application of excessive ongoing efficiency and the removal of stakeholder supported Totex allowances, resulting in the prospect of future outperformance being considerably more challenging than in RIIO-ED1.
FQ15. Do you believe there is new evidence which would support an adjustment downwards (eg expected outperformance) or (eg aiming up) that we have not yet considered?
Given the critical importance of delivering net zero, and the level of investment our stakeholders have supported over the RIIO-ED2 period to facilitate this, it is essential that Ofgem's cost of capital appropriately reflects the balance between the significant risks of underinvestment compared to the marginal impact of setting the cost of capital too high; it is this balance that has led regulators to "aim up" historically. Ofgem has not provided the full details of its financeability assessment, or the outcome of any stress tests performed. However, in the information provided, under the High expenditure case, before stress testing, some companies fall below the Baa1 rating[124]. Even before stress testing it is therefore clear that the metrics fall below the target credit rating of BBB+/Baa1, or the higher end of Moody's Baa1-Baa2 range for the notional company in RIIO-ED2. As set out in our response to FQ19, under a high expenditure, low RORE stress test scenario there is a significant deterioration in ratings for the WPD DNOs to below the Baa1-Baa2 range. The proposed RIIO-ED2 price control package also demonstrates a number of sources of risk asymmetry, as set out in the Oxera report submitted alongside this response[125], and the growing volatility around inflation and interest rates, and the resulting economic uncertainty, have resulted in a growing risk outlook for the sector. Aiming up on the allowed return on equity is therefore required to restore the balance in the price control. Given the level of investment required to deliver net zero, the focus on downside only incentives, the level of uncertainty mechanisms in RIIO-ED2, and the significant potential changes and risk in the sector, it is critical that Ofgem sets appropriate financial parameters which ensure companies are financeable under a range of scenarios, and aims up to ensure an appropriate level of resilience in the sector. The consequences arising from setting the allowed return too low are far greater than the consequences of setting it too high.

[123] p.7, CMA, RIIO-2 Energy Licence Modification Appeals, Summary of final determination, Issued: 28 October 2021.
[124] Table 20, p.73, Ofgem DD.
[125] Annex 8, Oxera, RIIO-ED2 Balance of Risks, prepared for the ENA, 22 August 2022

Inflation and WACC consultation questions

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

Aside from a change from RPI to CPIH indexation, the treatment of inflation within the price control has been consistent for many years. Ofgem reconfirmed the policy decision to index the RAV to inflation as part of the RPI-X@20 review[126] and investors value the current treatment of inflation within the price control.

The existing treatment of inflation is deeply embedded within the mechanics of the price control and any efforts to review or amend that treatment would need to be done with extreme caution involving substantial analysis and consultation. While we acknowledge inflation levels are currently very high, a knee jerk reaction risks spooking investors at a time when significant investment is needed in the networks for Net Zero. An adverse reaction could be detrimental for consumers. As well as putting Net Zero objectives at risk if financing is harder to achieve, the cost of capital could be increased due to increased perceptions of regulatory risk, causing an increased cost for consumers.

The leverage effect described by Ofgem in the Draft Determinations does exist in the near term where outturn inflation differs from ex ante expectations of inflation. Frontier Economics describe the leverage effect as an 'inverse inflation exposure'. In many respects this phrase is more apt as it reflects that fact that this is about a risk that is currently held by networks. It is important though to clarify whether the existence of this risk is an issue that needs to be addressed.

The risk is not new. Ofgem understood networks faced inflation risks with the cost of debt index when the RIIO-1 price controls were set. During the RIIO-1 process they stated, "The approach used to calculate the cost of debt index implicitly assumes that all network debt is index-linked. In reality, only a small proportion of the networks' debt is index linked and the networks are exposed to inflation risk on the rest of their debt profile."[127]

If, on average and over the long run, outturn inflation is approximately equal to the inflation forecasts used by Ofgem the network will not be over or under remunerated. This means any leverage effect is present only in the short term.

The data suggests that during RIIO-1 inflation has been below expectation. Frontier's report explains that Ofgem used breakeven inflation to set the cost of debt during RIIO-1 and that the inverse inflation exposure typically worked against shareholders over that period – "This implies that any investors who took on an inverse inflation exposure will have lost out overall during RIIO-1 to-date"[128]

Given the long run record it is by no means clear that any adjustment is required. In this context, a knee jerk reaction to now make an adjustment would result in accusations of regulatory opportunism and increased perceptions of regulatory risk which may cause an increase in the cost of capital and costs for consumers.

[126] Ofgem's RPI-X@20 review October 2010 'Handbook for implementing the RIIO model Ofgem' para 11.34
[127] Ofgem RIIO-T1/GD1 March 2011 Strategy Decision, paragraph 3.55
[128] Annex 13, Frontier Economics, Inverse inflation exposure, prepared for the ENA, 24 August 2022, page 8,

While the level of outturn inflation is beyond the control of networks, they are able to mitigate the impact on them of the leverage effect. Companies can choose how much index linked debt to raise and, in doing so, can choose to fully mitigate the risk by having 100% index linked debt, whether that be through raising index linked debt or synthetically creating it using derivatives.

It is unclear whether Ofgem is concerned about the notional or actual company. Companies can and do choose different strategies. If Ofgem adjusted their approach to inflation to address the leverage effect for the notional company, the actual company would still be subject to the leverage effect unless it chose a strategy to match the notional company.

While a change would not remove the leverage effect for actual companies, a change would create winners and losers. Bizarrely, a company that has fully or largely mitigated the risk by raising 100% or high levels of index linked debt would become significantly exposed whereas a company that has chosen to accept rather than mitigate the risk would suddenly find itself facing a different risk proposition. This would not seem equitable to either situation and it may take many years, and substantial cost, for a company to change its strategy in response to any change in treatment. There is a need to signal material changes in risk profile such as this well in advance unless Ofgem is prepared to compensate or fund networks for the costs of adjusting their financing strategies.

Equally, if instead Ofgem sought to remove the leverage effect for the actual company, this would be a material departure from the long-established position that individual companies can choose their own financing structure, and, by implication, suffer the risks and rewards of their choice. We note the Draft Determinations remain in favour of the notional company approach, for example "The notional company approach reflects the principle that companies and their investors are best placed to bear the risks associated with their borrowing choices."[129]

Ofgem should not attempt to remove the inverse inflation exposure in RIIO-2. To do so would de-stabilise the credibility of the regulatory framework and shake investor confidence. As summarised by Frontier, "This de-stabilisation would be detrimental for consumers – it would increase perceptions of regulatory risk and can be expected to lead to higher financing costs and risk management costs; and it would detract from the critical objective of securing potentially significant increases in investment to deliver Net Zero. Ultimately it can be expected to lead to unnecessary increases in customer bills in the long run."[130]

If, despite this, Ofgem were to contemplate a change in the treatment of inflation they should only do so after considerable engagement and consultation, avoiding retrospective changes, and signalling well in advance (i.e. at least several years) of any implementation date the changes being envisaged so networks can adjust their financing strategies accordingly. Any implementation should coincide with the setting of a new price control rather than reopen an existing control.

These steps are essential to avoid accusations of regulatory opportunism and increased perceptions of regulatory risk which may otherwise cause an increase in the cost of capital.

[129] Para 2.4, Ofgem RIIO-ED2 Draft Determinations – Finance annex
[130] Annex 13, Frontier Economics, Inverse inflation exposure, prepared for the ENA, 24 August 2022, pages 3-4

FQ17. If you believe we should make such an adjustment, what is the best method for making it?
As per our response to FQ16 we do not believe an adjustment should be made. The treatment of inflation is deeply embedded within the price control in many ways. It would take a considerable amount of time to carefully consider the various interlinkages and complexities to avoid unforeseen consequences. Even if adjustments were considered appropriate it would be unwise to suggest possible adjustments until such a review had been completed. We highlight below a mere flavour of some of the complexities that would need to be considered: • Any options considering alternative inflation forecasts fail to fully address the leverage issue unless there is a true up for the actual inflation rate. • Ofgem has previously taken steps (including setting charges 15 months in advance) to increase the predictability and stability of charges for the benefit of consumers. Any options that increase the volatility and unpredictability of the allowed return would undermine these measures and be bad for consumers. • Options such as a Return Adjustment Mechanism (RAM) could undermine the already weak incentives within the ED2 control if high or low inflation triggers the RAM and dilutes the impact of incentives on returns • Options that amend the inflation of the RAV would require a detailed consideration of how the indexation of revenues should be adjusted. There is insufficient time to consider the complexities involved for RIIO-ED2. For this reason there should be no changes until RIIO-3, if at all.
FQ18. If you don't believe we should make such an adjustment, how should we ensure that the fairness of the price control is maintained to prevent ex post returns from deviating from ex ante expectations for both consumers and investors?
As per our response to FQ16 we do not believe an adjustment should be made and note that Ofgem did not consider the current approach unfair when consumers benefitted from the difference between expected and actual inflation. The text of question FQ18 implies that it is unfair if ex post returns deviate from ex ante expectations yet Ofgem already allows for and anticipates ex post returns deviating from ex ante expectations as a result of risks borne by investors. For example totex and ODI incentive performance results in deviation and Ofgem believes investors should be exposed to the risks and returns from companies' financing choices.[131] Ex post returns deviating from ex ante expectations does not make those returns unfair. The inflation leverage effect referred to by Ofgem, or 'inverse inflation exposure' as described by Frontier, is a risk borne by companies and their investors and that is why no such adjustment is required. This is a risk that companies can choose to mitigate (or not) by choosing what proportion of their debt to index link. Networks will have chosen how best to respond to or mitigate the risks they face and will have

[131] Para 2.4, Ofgem RIIO-ED2 Draft Determinations – Finance annex

different strategies when it comes to index linking debt. These strategies will have been established and implemented over many years. It would be inappropriate for Ofgem to now change long established practice for indexation of the RAV and setting of the WACC.

We note that, while Ofgem has not set out detailed proposals, nothing has been written to suggest Ofgem also intends to address any of the other issues and treatments within the price control that leave networks exposed to other risks associated with inflation. These risks include:

- The RPI-CPIH wedge assumed in the cost of debt allowance may differ from the actual RPI-CPIH wedge. Most index linked debt is linked to RPI rather than CPIH. As of May 2022 RPI inflation was 11.7% and CPIH inflation was 7.9% giving a wedge of 3.8%. The wedge assumed by Ofgem is of the order of 300 bps or so lower. This shortfall on the cost of debt allowance partially offsets the leverage effect and, for companies with a high proportion of index linked debt, could cause significant losses to shareholders.
- Ofgem uses forecasts of CPI as a proxy for CPIH but CPI and CPIH can be and are currently very different. The gap between CPI and CPIH has grown markedly recently.
- As mentioned in FQ1, Ofgem's own modelling of the cost of debt index[132] shows that Ofgem expect debt underperformance of 2bps but that this deteriorates by a further 11 bps for a 1% increase in inflation.

Absent changes to address these other issues Ofgem is already accepting that networks are exposed to some inflation risk and it would be highly selective for Ofgem to choose to address one risk while ignoring the others, particularly when the impact of those risks partially offset each other.

Aside from a change from RPI to CPIH indexation, the treatment of inflation within the price control has been consistent for many years and, as explained in FQ16, the specific case now being considered by Ofgem was confirmed as being a deliberate policy choice by Ofgem[133]. Ofgem has focussed on one inflation risk within the price control rather than all of the risks, and has chosen to do so when that one risk is currently operating to the benefit of shareholders. Ofgem did not raise the prospect of reviewing the inflation risk when inflation was below long run expectations and working to the benefit of consumers. To selectively change longstanding practice for one issue would not be fair.

The best way to ensure the fairness of the price control is maintained is to maintain the current balance of risk and treatment of inflation. If Ofgem considers change to be necessary then a proper review should be conducted considering all of the risks, interlinkages and complexities involved. The treatment of inflation is deeply embedded within the price control in many ways and such a review would need to be done properly to avoid unforeseen consequences. There is insufficient time to do this for RIIO-2.

[132] Table 7, p. 22, Ofgem, RIIO-ED2 Draft Determinations – Finance Annex, 29 June 2022
[133] Ofgem RIIO-T1/GD1 March 2011 Strategy Decision, paragraph 3.55

Consultation questions on Financeability

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

Table 20 of the Finance Annex only presents the Adjusted AICR and the FFO/Net debt ratios for each licensee under Ofgem's Base and High expenditure cases. No results of Ofgem's stress tests based on the DD proposals have been provided, or included in the DD PCFM.

In response to our supplementary question asking for details and the outcome of Ofgem's stress tests, Ofgem responded that it was not practical to share all the outputs of the financeability scenarios, and not all scenarios were relevant given this is an iterative rather than mechanistic process, reflecting Ofgem's in-the-round assessment.

It is therefore difficult to understand the level of financeability assessment Ofgem performed, the expenditure scenarios this was performed upon, whether appropriate weight has been given to the process, or the approach Ofgem has taken to determine whether the proposed package is financeable.

Given the amount of expenditure that has been moved into Uncertainty Mechanisms, it is not appropriate to place weight on a financeability assessment under the Base case, as this is not representative of likely company expenditure levels. Further, Ofgem's high expenditure case still does not include outcomes under all Uncertainty mechanisms and should therefore not be considered a stress test scenario but the more realistic of the two scenarios.

We have run scenarios and stress tests for the WPD DNOs in the DD PCFM Ofgem provided. Under the High expenditure case, with the exception of gearing, which is within the A rating range, and the FFO/Net debt which declines over the period to below the Baa range in SWALES and SWEST, the ratios are in the middle of the Baa/Baa1-Baa2 range. Even before stress testing it is therefore clear that the metrics fall below the target credit rating of BBB+/Baa1, or the higher end of Moody's Baa1-Baa2 range for the notional company in RIIO-ED2.

The Low RoRE scenario is designed to capture the impact of potential underperformance on totex, incentives and/or debt costs. Ofgem states that "an appropriate downside performance scenario for an individual notional licensee might reasonably fall in the range of 100-200bps RoRE."[134] However, the extent to which Totex has been stripped out of Business Plans increases the likelihood of Totex overspend. Coupled with the downside asymmetrical incentive structure set out in the Draft Determinations, the likelihood of RoRE downside performance being greater than 200bps is not insignificant.

Ofgem clearly considers there is a likelihood of RoRE underperformance of beyond -100bps, given the calibration of the Return Adjustment Mechanism (RAM) which is set to kick in at 1.75% RoRE (300 bps below the baseline) and 0.75% RoRE (400 bps below the baseline).

Under a high expenditure, low RORE stress test scenario (RoRE -2%) there is a significant deterioration in ratings to below the Baa1-Baa2 range, with AICR dropping to an ED2 average of 1.03 – 1.06 across the WPD DNOs, FFO/Interest dropping to an ED2 average of 3.12 - 3.39, FFO/Net debt dropping to an ED2 average of 9.41%-10.71%. RCF/Net debt is just within range at an ED2 average of 7.0% - 8.27%.

[134] Para 5.59, p.76, Ofgem DD

In the Finance Annex, Ofgem states that "While AICR metrics are tight for all licensees relative to typical investment grade levels for that metric alone, overall credit ratings are consistent with a comfortable investment grade rating."[135] However, AICR, along with Net debt/RAV, is one of Moody's two primary ratings therefore the extent to which performance on secondary ratios can "offset" performance on the primary ratios is limited. It is essential that companies are not simply financeable, but have a robust enough financial position to withstand unforeseen shocks. Given the increased level of risk set out above, Ofgem must ensure that companies have an appropriate level of financial resilience. Based on the metrics before and under stress testing, it does not seem that this is the case in the proposed DD package.
FQ20. Do you have any evidence that would enable us to improve our calibration of stress test scenarios?
The full outcome of Stress tests should be published. Stress tests should be calibrated on the High case expenditure scenario, and it would be appropriate to have a further scenario reflecting additional expenditure, and consequent allowances, under Uncertainty Mechanisms. Stress tests should represent an appropriate RoRE downside which is reflective of outcomes under the DD package. In light of Ofgem's policy decisions, this adjustment should be at least 200 bps.
FQ21. Do you agree with the requirement to provide the Financial Resilience Report within 60 days?
The license already contains protections ahead of dropping below Investment Grade. Ofgem does not state what will be required to include in any Financial Resilience Report, therefore it is unclear whether this is a proportionate request. Further, the purpose of the report, i.e. what Ofgem will do with the information, is not stated. The referenced SSMD paragraph does not give any further details regarding the actions Ofgem would take once receiving the report. We note that the outcome of Ofgem's financeability testing, before stress tests, shows companies at Baa2 under the High case expenditure scenario. Introducing a requirement for companies to provide further information to Ofgem does not compensate for Ofgem setting inadequate returns in a price control that is not financeable. It should be noted that sharing of any credit report with Ofgem can only be done if permitted by the relevant rating agency. The impact on companies increasing reporting requirements such as this should be considered, and the benefit assessed against the increased regulatory burden, which is not without cost which is eventually passed to customers, and has the potential to be a distraction for management at a critical time.

[135] Para 5.49, p.73, Ofgem DD

Consultation questions on corporation tax

FQ22. Do you agree with our proposals to make allocation and allowance rates variable values in the RIIO-ED2 PCFM?
Yes – this approach appears appropriate and more straightforward than the use of the tax trigger. Further, updating allocation to tax pool rates will reduce divergence from actual pools where expenditure varies from that anticipated (e.g. through UMs).
FQ23. Do you agree with the proposed additional protections? In particular:
The introduction of any Tax reconciliation or Tax review are highly dependent on the design of any related reporting template and guidance and potential consequent adjustments. This would be a significant and time consuming task, with a substantial amount of reconciling items. The RFPR commentary document may not be the appropriate place for discussion of reconciling items - this could be an extremely detailed and technical analysis. There are numerous legitimate reasons why there may be differences between a DNO's tax allowance and its statutory tax charge, including: • incentive performance, • differences between a DNO's actual financing structure and Ofgem's assumed notional company structure, • non-distribution activities, • tax trigger events that have an effect below the materiality threshold in any given year, and • regulatory timing differences e.g. under/over recovery. The Tax reconciliation should be designed in a way that these legitimate differences can be reflected without triggering a tax review. Further, the current drafting does not impose a limit on the size or scope of adjustment Ofgem can make as a result of any Tax review. It seems appropriate that the quantum of any allowance difference directed by Ofgem should be constrained to the quantum of the "unexplained difference". We will continue to engage with Ofgem on the drafting of the relevant licence condition and the Handbook. In relation to the proposed Board Assurance statement, we do not object in principle to the provision of a board assurance letter, although we question whether it is required given that any submissions under the RFPR will already have been through the Data Assurance process. If Ofgem requires any assurance over tax information provided, we propose a return to the submission to Ofgem of a copy of the Senior Accounting Officer certifications provided to HMRC, as previously provided alongside the RRP submissions, plus submission of NWOs' published tax strategy documents. If Ofgem does pursue this requirement, it would be more appropriate for directors to make statements about the diligence with which the DNO has undertaken the mechanics of populating any reconciliation template and quantified and explained any variances, rather than statements regarding the operation of the Ofgem reconciliation template.

In relation to the Tax review, Ofgem's approach should be symmetrical, meaning adjustments could both increase and/or decrease a licensee's tax allowance. If the approach is not symmetrical, would a review only be triggered if the notional allowance exceeded actual tax liability? The ability for a review to be notified to Ofgem by other stakeholders or licensees could result in a considerable amount of work for both Ofgem and licensees based on speculative requests from other parties. The wording should also include details of how any tax adjustment would be calculated.
FQ24. Do you have any views on a materiality threshold for the tax reconciliation?
Given the potential for differences in price bases, timing differences and the many other sources of legitimate differences between the tax allowance and actual tax charge, it is appropriate to have a materiality threshold for the tax reconciliation, and the use of the tax trigger deadband appears appropriate. However, it is unclear whether the directed value would be the amount above the materiality threshold or the full amount.
FQ25. Do you think that the "deadband" used in RIIO-ED1 is an appropriate threshold to use? If not, what would be a more appropriate alternative?
As stated in FQ24, the tax trigger deadband appears appropriate. However, it is unclear whether the directed value would be the amount above the materiality threshold or the full amount.
FQ26. Do you have any views on our proposals relating to the Tax Trigger and Tax Clawback mechanisms? In particular, do you have any views on a proposed “glide path” for the notional gearing levels used in the tax clawback calculation?
We welcome the “glide path” for the notional gearing levels used in the tax clawback calculation.

Consultation question on Return Adjustment Mechanisms

FQ27. Do you agree with our proposals for the RAM thresholds and adjustment rates? Consultation question on indexation of the regulatory asset value (RAV)
We consider the RAM to be appropriately calibrated.
FQ28. What are your views on the technical implementation of the switch to CPIH as set out in the attached PCFM?
We consider the principle of the technical implementation of the switch to CPIH to be appropriate; there may be particular balances for which the impact of the change will need to be assessed on an individual basis; for example pension deficit repair allowances. Ofgem will need to ensure that the switch from RPI to CPIH is done correctly and gives the correct opening RAV balance for RIIO-ED2.

Consultation question on regulatory depreciation and economic asset lives

FQ29. Do you agree with our proposal to set depreciation policy on RAV additions in the RIIO-ED2 period to 45-years straight line, based on the average economic life of the assets?
We welcome Ofgem's proposal to set RAV depreciation at 45 years straight line for RIIO-ED2; as stated in our Business Plan, our stakeholder engagement has indicated that regulatory certainty and predictability is a key factor for investors. We also firmly believe that the detailed review of asset lives Ofgem conducted in 2011 was intended as a long term policy decision and should not be reopened for RIIO-ED2 to solve financeability issues; this could have the unintended consequence of increasing returns over the longer period by undermining Ofgem's reputation for predictability.

Consultation question on capitalisation rates

FQ30. Do you agree with our proposal that we should set different capitalisation rates for ex ante allowances and re-openers and volume drivers?
We do not object to the principle of split capitalisation rates; if the rates are calibrated correctly then each type of expenditure should be capitalised in the same way whether it sits within Base or Variant expenditure. However, we do not consider the current proposed rates to be appropriate. In our Business Plan, we highlighted that the natural capitalisation rate for WPD's licensees for RIIO-ED2 ranges from 77.5% to 81.0%, varying by year and by licensee depending upon the mix of work. This is a blended rate across all expenditure in our Business Plan. Ofgem's proposed capitalisation rates for Base expenditure for WPD's licensees for RIIO-ED2 ranges from 78% to 80%. Ofgem has moved a considerable amount of expenditure out of our Baseline allowance and into Uncertainty Mechanisms, and is proposing a 98% capitalisation rate thereon. Taking into account this expenditure, plus amounts remaining within Base Totex, this would give a blended capitalisation rate which is significantly higher than our natural capitalisation rate. It is unclear how Ofgem has derived the 98% capitalisation rate for Uncertainty mechanisms, which is a flat rate across all DNOs. Further, it is unclear how the above then reconciles with Ofgem's statement that "We agree with submissions that natural rates of capitalisation are desirable. Regulatory capitalisation rates reflecting the natural rates of capitalisation help ensure, over time, that charges are fair."[136] A capitalisation rate of 98% is deferring all but 2% of costs to future customers; it is unclear how this aligns with Ofgem's statutory duty to protect the interests of existing **and future** consumers.

[136] Para 10.26, p.107, Ofgem ED2 DD.

We do, however, welcome the statement in response to our supplementary questions that Ofgem will seek updated capitalisation rate inputs from DNOs in the coming months to refresh the PCFM, which will give licensees an opportunity to provide natural capitalisation rates for variant activities that Ofgem have added in. It will also be necessary for Ofgem to seek updated capitalisation rate inputs for Base expenditure, as the profile of costs within this expenditure will be different from that when the original rates were calculated, given that some types of expenditure have been moved into the Variant category. In response to our supplementary questions, Ofgem also told us that the capitalisation rate for the Base and Variant expenditure is to be fixed ex-ante. However, given that Variant expenditure levels are, by nature, uncertain, it is unclear how Ofgem can reflect appropriate capitalisation rates for variant activity where the level of cost, and the cost category of potential costs incurred, are not yet known. For example, how the capitalisation of costs under the Net zero reopener, or Specified Street Works expenditure, should be reflected in an ex ante capitalisation rate. We suggest that Ofgem should either set a capitalisation rate for variant expenditure that is closer to WPD's natural capitalisation rate, or allow for the capitalisation rates of variant expenditure to be updated throughout the price control, to account for uncertain levels and types of expenditure. It should also be noted that in our Business Plan, WPD proposed a capitalisation rate of 75% which improved the financeability of our plan. Changes to capitalisation rates are one of the 'levers' Ofgem highlights for companies to consider adjusting to improve the financeability of the Business Plan. Our response includes a report from PA Consulting for the ENA, Assessment of the Capitalisation Rate Applied to Uncertainty Mechanisms in the RIIO-ED2 Draft Determinations[137], and we look forward to working further with Ofgem ahead of Final Determinations to review capitalisation rates
FQ31. Do you have any evidence that would enable us to improve our estimates of regulatory capitalisation rates?
We have provided information on our natural and proposed capitalisation rates in our Business Plan and BPDT submissions. As stated in response to FQ30 above, we welcome Ofgem's intention to seek updated capitalisation rate inputs from DNOs in the coming months to refresh the PCFM, and stress that Ofgem will require capitalisation rates for variant activities and updated capitalisation rates for Base expenditure, as the profile of costs within this expenditure will now be different from that when the original rates were calculated, given that some types of expenditure have been moved into the variant category. The report from PA Consulting highlighted in response to FQ30 provides further analysis.

[137] Annex 9, PA Consulting, Assessment of the Capitalisation Rate Applied to Uncertainty Mechanisms in the RIIO-ED2 Draft Determinations, prepared for the ENA, 23 August 2022

Consultation question on RAV opening balances

FQ32. Do you have any views on the use of forecast RAV opening balances for the start of RIIO-ED2, which will be trued-up following RIIO-ED1 closeout?
In relation to forecasting opening RAV balances, we consider this to be a pragmatic and appropriate approach to take. We note that Ofgem also proposed to take the closing capital allowance pool balances and regulatory tax loss balance from an adapted RIIO-ED1 PCFM that is to be used to calculate the provisional LMOD2022/23 value. However, it should be noted that the closing capital allowance pool balances will not reflect the impact of the super deductions in 2021/22 and 2022/23, as these do not flow though the RIIO-ED1 PCFM and instead are adjusted as Type B tax trigger events. Further adjustments will therefore be required to the ED1 PCFM closing tax pool balances to arrive at the correct opening tax pool balances for RIIO-ED2.

Consultation question on transparency through RIIO-ED2 reporting

FQ33. Do you agree that additional corporate governance reporting described (including on executive director remuneration and dividend policies), will help to improve the legitimacy and transparency of a company's performance under the price control? If not, please outline your views in relation to the rationale provided for these additional requirements, including consumer protection.
As we have previously stated to Ofgem, we have concerns about the additional information requirements in relation to directors' remuneration. The RIGs makes clear that the collection of information is to enable Ofgem to administer the Conditions of the Licence (the conditions which relate to the price control) which include monitoring the performance of Licensees against Ofgem's final proposals/determinations, monitoring compliance with price control obligations and allowing analysis between price controls and at the subsequent price control review. The consultation document provides no explanation of how Ofgem will use the information or evidence that it is required by third parties. It is therefore inconsistent with Ofgem's information collection and reporting simplification objectives. We do not support including narrative around executive remuneration. A requirement to disclose personal data/information for publication is not one that Ofgem should impose and also conflicts with requirements in respect of good corporate governance and the disclosure of directors' remuneration set by Parliament, the FCA or any exchange on which a company's securities are listed. Information is already provided in the Statutory Financial Statements, for those companies which are required to disclose such information, where it is subject to external audit and presented in a common way across the UK. The RFPR information would not be subject to the same reporting or auditing standards. In relation to the new requirements for licensees to report on their ownership, board governance and decision-making, again this appears to duplicate information required

in Statutory Financial Statements and require the provision of information beyond the regulatory business.

Questions on consolidated reporting and calculation of allowed revenue

FQ34. What are your views on the proposed consolidation of the revenue RRP and PCFM, or applying a fully dynamic concept of allowed revenue?
This approach appears to be acceptable, provided that Ofgem provides the appropriate guidance in terms of forecasting RIIO-ED2 values, and the calculation of values in the transition from RIIO-ED1 to RIIO-ED2, and develops models in a timely manner so companies have time to familiarise themselves with these. This will involve a significant amount of work and should not be underestimated.

Questions on licensee self-publication of allowed revenue

FQ35. What are your views on allowing licensees to self-publish the PCFM with their charging statements, rather than relying on an Ofgem publication or direction to determine allowed revenue?
We don't object to the self-publication process in principle and welcome Ofgem's statement that it will publish a consolidated (i.e. all DNO) version of the PCFM annually. If there is a move to self-publication, the licence documents must make it very clear how Variable Values are to be calculated, including guidance on how to make "best estimates" – for example, the stage at which any additional revenues under possible reopener applications or other Uncertainty Mechanisms should be reflected and assumptions to make in relation to these. This will require a significant amount of drafting effort from Ofgem and DNOs. It should also be noted that a move to self-publication as set out above would not, and should not, increase the amount of discretion companies will have in relation to the forecasting of Allowed Revenue. The licence should be prescriptive enough to ensure that the calculation of Variable Values is consistent across the sector.

Questions on best vs reasonable endeavours in charge setting

FQ36. What are your views on having a best endeavours obligation for charge setting: "The licensee must, when setting Network Charges, use its best endeavours to ensure that Recovered Revenue equals Allowed Revenue"?
To summarise to the distinction between "reasonable endeavours" and "best endeavours", with regard to "best endeavours", this is an obligation to take all steps in a party's power which are capable of producing the desired result, that a prudent,

determined and reasonable party acting in his own interests and desiring to achieve that result, would take. Further, depending on the nature and terms of the obligation, it may require a party to subordinate its own commercial interests and to incur expenditure or a loss. For "reasonable endeavours" however, a party can consider its commercial interests, relations with third parties, its reputation and costs when considering the steps it should take in order to satisfy the obligation.

We disagree with Ofgem's proposal to introduce a "best endeavours" obligation for charge setting and consider that the obligation should remain a "reasonable endeavours" obligation.

Ofgem made a conscious decision to require DNOs to use reasonable endeavours when setting network charges for RIIO-ED1 and has not adequately justified its proposal to impose a more onerous obligation.

Ofgem's argument for making this change seems to rely on three pieces of logic:

- That the obligation is arguably "the most fundamental obligation" in the price control;
- That greater responsibility is appropriate given the expectation that licensees will self-publish the value of allowed revenue; and
- That making the change would bring ED into line with other sectors.

These arguments are not sufficient, individually or collectively, to justify the proposed change. Furthermore, Ofgem has failed to recognise that it would be inconsistent to increase this obligation at the same time as making other changes to the price control package such as removing the two-year lag which applies to many aspects of the price control flowing through to Allowed Revenues.

Additionally, while Ofgem has recognised that the introduction of such an obligation would cause DNOs to incur additional costs in meeting a more stringent obligation, Ofgem has failed to fund DNOs to undertake those activities.

We expand on these points further below.

1. Ofgem's argument that a change is required to reflect "the most fundamental obligation in the price control" fails to recognise (a) the increasing costs to be funded by consumers without additional benefit or (b) the safeguards that are already incorporated into the price control to protect customers from any deviation between Allowed Revenue and Recovered Revenue

DNOs take their obligations in respect of setting network charges seriously and recognise the importance of taking appropriate care in setting network charges. However, there is a balance to be struck between the effort expended (and costs incurred) in chasing increased accuracy of network charges and the extent to which incremental efforts actually result in improvements that benefit customers.

In order to set network charges so that Recovered Revenue equals Allowed Revenue, DNOs have to forecast the level of Allowed Revenue and the amount of electricity that will be used by different customer groups during the relevant Regulatory Year. The level of uncertainty in both components is already considerable, and is expected to increase for RIIO-ED2.

We remain concerned that the costs incurred in meeting the more stringent obligation may not be in customers' interests and may run counter to other policies that customers value, especially the requirement to give 15 months' notice of changes to network charges.

Any efforts to further improve the accuracy of forecasting of network charges will only ever make marginal improvements. The costs incurred to do so may be considerable and any marginal improvements in accuracy will be dwarfed by the general uncertainty associated with forecasting many material aspects of both Allowed and Recovered Revenue.

There are other existing safeguards in place to protect customers from the adverse effect of network charges being set in a way that does not lead to Recovered Revenues matching Allowed Revenue. These safeguards include under- and over-recovery mechanisms that ensure that customers ultimately pay the appropriate amount, and penalty interest calculations that apply to any material deviations between Allowed Revenue and Recovered Revenue. These are far more effective safeguards than Ofgem's proposal to change the level of obligation.

1.1. Ofgem has failed to provide examples that justify increasing the obligation, and has not answered the examples provided by DNOs that demonstrate the additional costs that would be incurred in chasing very marginal improvements in accuracy of network charges

The current obligation to use reasonable endeavours is already a strongly phrased obligation. Ofgem has also not yet provided any examples of shortcomings with the current DNO processes that merit any increase in obligation standard.

DNOs accept that there have been some instances where DNOs' Recovered Revenues have not matched Allowed Revenue during RIIO-ED1. However, these have largely arisen due to significant exogenous factors such as the effect of the Covid-19 pandemic on consumption by different customer groups, the changes in Allowed Revenue due to Supplier of Last Resort (SoLR) obligations and the change in customer behaviour following the recent material increases in energy prices. These simply would not have been forecast in advance under any obligation standard, and especially at 15 months' notice.

While some components of Allowed Revenue and Recovered Revenue can be forecast with some accuracy at the time of setting network charges, many simply cannot. Those factors that can be readily and accurately forecast will already be forecast with appropriate accuracy under the current reasonable endeavours requirement.
In contrast to Ofgem's approach, DNOs have provided Ofgem with specific examples of activities that could be required under a best endeavours obligation. Most have not been addressed in Ofgem's justification for proposing a best endeavours obligation.

It is illogical to impose such an increased burden in the face of clear evidence that increasing the obligation would increase costs for very limited, if any, customer benefit.

1.1.1. Example: Uncertain costs – uncertainty mechanisms

Ofgem proposes to set baseline totex allowances "only where [it] are satisfied on the need for and certainty of the proposed work". (DD overview paragraph 6.2) Totex allowances for all activities where uncertainty remains will be set via uncertainty mechanisms.
In setting network charges, DNOs need to estimate future totex allowances associated with these uncertainty mechanisms without knowing actual performance or need and ahead of any re-opener submission or Ofgem decision. Ofgem acknowledges that "Forecasting costs and outputs with confidence for the duration of a price control is challenging". (DD overview 6.5) These uncertainty mechanisms may amend totex allowances for any year of the price control. This is different from RIIO-

ED1 where the decision would result in an amended MOD term that would apply to future Allowed Revenues.

Any move to a best endeavours standard would require considerably more expenditure by DNOs in predicting acknowledged uncertainties. In addition DNOs would need to engage regularly with Ofgem to understand its intended outcome of reopener processes, and for Ofgem to provide written confirmation which could then be used as part of the forecasting process. There would appear to be little or no real benefit to electricity consumers from this extra work.

1.1.2. Example: Uncertain costs – pass-through

Ofgem proposes to introduce cost pass-through mechanisms "for costs incurred by the DNO over which they have limited control". (DD overview paragraph 6.4) Pass-through items represent costs that are either outside DNOs' control (such as business rates) or that have been subject to separate price control measures (such as Transmission Connection Point Charges and Smart Meter Communication Licensee Costs).
Pound for pound, any difference between forecast costs and costs ultimately incurred has a bigger impact on the difference between Allowed Revenue than other cost areas (because all costs flow directly to in-year revenues).

A best endeavours obligation would oblige DNOs to incur additional costs forecasting these activities, despite these being acknowledged to be outside of DNOs' control or subject to separate regulatory processes.

For example, in the case of forecasting of supplier of last resort payments, the change to a best endeavours basis may well oblige the DNOs to carry out much closer and more frequent monitoring of supplier financial health on an ongoing basis, such as employing special analysts to assess the likelihood of suppliers ceasing to trade and, therefore, incurring the associated additional cost. Customers would not benefit from this incremental cost.

1.1.3. Example: Sales response to external stimulus

In estimating future Recovered Revenue, DNOs have to forecast the amount of electricity that will be used by different customer groups during the relevant Regulatory Year. Historically, the biggest factor affecting customer usage has been the weather (in itself, not a factor that it is easy for DNOs to forecast 15 months ahead). However, increasingly uncertain times mean that there is much greater uncertainty about future electricity usage.

Factors such as changes in customer working practices, response to wholesale energy prices and government policy changes designed to achieve the UK's transition to net zero can all materially change consumption by individual customer groups.

A best endeavours obligation applying to forecasting of Recovered Revenue could suggest an expectation by Ofgem that DNOs invest considerably more effort in detailed forecasting of the macro-economic and political factors that drive this. There is no evidence to suggest that more effort in forecasting these factors, and the cost of doing so, will be in customers' interests.

1.1.4. Example: Setting of network charges for RIIO-ED3

The proposed best endeavours obligation would apply to DNOs when setting network charges for the first years of the RIIO-ED3 period. More than half of the routine annual cycles of setting network charges undertaken in RIIO-ED2 will involve setting network charges for the RIIO-ED3 period. Ofgem has provided no guidance on its expectations here.

It is very unlikely that DNOs would have visibility of sufficient aspects of the future price control to accurately set network charges on that basis 15 months in advance.

1.1.5. Example: Considering whether to seek consent to re-set network charges with less than 15 months' notice

Once network charges have been set, the only recourse DNOs have if it becomes clear that Allowed Revenue and Recovered Revenue are divergent would be to seek Ofgem's consent to re-set network charges at very short notice, in time to affect in-year revenues. The move to best endeavours is likely to result in an additional burden for Ofgem in considering requests as well as more frequent, later, changes to network charges. Such a requirement could be triggered by any factor that affects Allowed Revenue or Recovered Revenue in a Regulatory Year for which network charges have already been set including a change in forecast inflation or the forecast risk free rate, or any change in legislation that could result in additional expenditure.

Moreover, it is not clear in the current drafting that "setting Network Charges" refers to an event that happens only once for each regulatory year. Setting network charges is an activity that DNOs undertake at least once a year (and sometimes more often). The obligation could be read as requiring DNOs to use their best endeavours to lobby Ofgem to waive the 15 months' notice requirement for setting network charges that have already been set every time they go through the process of setting network charges.

2. Ofgem's suggestion that the proposed move to self-publishing the Allowed Revenue justifies the change in obligation misrepresents the extent to which this change will improve DNOs' ability to forecast Allowed Revenue more accurately

Ofgem partially justifies its proposal to move to a best endeavours obligation by reference to its proposal that Licensees will be given more control of the process of setting Allowed Revenue.

This process change does not impart on DNOs any significantly greater ability to forecast Allowed Revenue accurately. While there will be some components of Allowed Revenue that DNOs may have superior forecasts than are available to Ofgem, such as latest expenditure plans for certain activities, it is not the case that DNOs have a universal view of all future expenditure, economic conditions, legislative decisions, etc.

DNOs will still be required to forecast Allowed Revenue based on the algebra specified in the licence. As explained in the examples above and in DNOs' correspondence with Ofgem, a considerable proportion of the elements of Allowed Revenue is subject to forecasting uncertainty. Increasing the level of obligation will not increase a DNOs' visibility of accurate forecasts without considerably effort being expended.
The move to self-publishing the Allowed Revenue will also not change the considerable challenges associated with forecasting customer consumption.

Ofgem recognises that this new process of self-publishing Allowed Revenue will need to be supported by sufficient guidance (DD Finance annex paragraph 10.123). Once such guidance has been developed, it would be far more appropriate to oblige the DNOs to comply with this guidance than to introduce a broader obligation that may result in costs being incurred that are not in customers' interests.

The change in standard for DNOs cannot be justified by reference to the standard applied in other sectors

Ofgem partly justifies its approach by reference to a desire for alignment between sectors. The DD rightly states that there "should be a reason for inconsistency between sectors" (DD finance annex paragraph 10.129). The DNOs believe that there are strong reasons to justify a different approach for electricity distribution.
The process for setting network charges for DNOs is quite different from other sectors, such as gas distribution. Ofgem considered these differences in reaching its decision in respect of RIIO-ED1 and concluded that it was appropriate to set the level of obligation at a lower standard for DNOs than for GDNs or TOs.

The arguments for DNOs to have a different approach from other sectors have strengthened during RIIO-ED1, in particular with the introduction of the requirement to give 15 months' notice of changes to network charges and the additional forecasting complexities and difficulties associated with that.

These forecasting difficulties will be compounded by the extra costs that will be incurred due to Ofgem's intended move to a greater proportion of costs being included in in-year revenue calculations. Ofgem's proposal to remove the lag to changes flowing into Allowed Revenue that is applied in RIIO-ED1 to many mechanisms further increases the difficulty associated with forecasting Allowed Revenue, and the costs that would need to be incurred to meet a best endeavours obligation. Where GDNs will set network charges in possession of the majority of the actual economic data, performance and spend data that will flow into the Allowed revenue calculations, DNOs will set network charges in the absence of that data.
In reality, the complexities and difficulties involved in setting network charges will increase from RIIO-ED1 to RIIO-ED2, even without any change to the level of obligation applied. This will cause DNOs to incur additional costs. These costs will ultimately be borne by customers.

This increases the difference between ED and GD and justifies continuation of a different performance standard. Alignment between sectors simply cannot be used to justify this change.

3. Ofgem's proposed change to the level of obligation is internally inconsistent with its proposal to remove the current lag on many aspects of economic condition or performance flowing through to Allowed Revenue

Ofgem proposes to remove the lag that currently applies to many aspects of the price control. Ofgem acknowledges that the current lag in performance flowing through the revenues was introduced to improve predictability of charging (DD finance annex paragraph 10.163).

At present, DNOs have access to approximately three quarters of the performance data for aspects of the price control that are lagged by two years at the time of setting network charges (15 months prior to the relevant Regulatory Year commencing). The fact that DNOs did not have access to all of the performance data when setting network charges for RIIO-ED1 was part of Ofgem's rationale for applying a lower standard to DNOs than GDNs.

For RIIO-ED2, DNOs will not have access to any of that data and will have to rely on forecasts, and the costs of developing those forecasts for some aspects of the price control to a best endeavours standard could be considerable.

Ofgem also plans to change the approach to forecasting of inflation with the removal of the current approach of forecasting inflation using a standard forecast (RPIF) and truing up to actual inflation (RPIA) on a lagged basis once actual data is available (see draft SpC 2.1 para 2.1.9). Inflation shocks are very difficult to forecast and can drive very significant differences between forecast and actual Allowed Revenue calculations. This change will further increase the difficulty of providing accurate forecasts of Allowed Revenue.

Ofgem has recognised the difficulties associated with forecasting several material aspects of Allowed Revenue in its proposal that inflation and incentives should not be subject to penalty interest (DD finance annex paragraph 10.160). It is illogical for Ofgem to insist that DNOs should incur the costs associated with meeting a best endeavours standard for forecasting such aspects of Allowed Revenue when elsewhere in the price control package it recognises the difficulty of achieving accuracy.

4. If Ofgem has views as to specific actions that DNOs should undertake, it should make those requirements clear on face of the licence rather than imposing a generic obligation

Ofgem suggests that DNOs' interpretation of the expectations of a best endeavours obligation may be more onerous than its own expectations of the actions required to achieve the obligation (DD finance annex paragraph 10.127).

Ofgem's articulation in the Draft Determination of its expectations on DNOs is not fully consistent with our understanding of case precedent related to the requirements under a best endeavours obligation. Best endeavours is clearly a legal test and we would expect that, unless further qualified by the licence, it would be this legal test that would be considered during any potential enforcement action. In the absence of specific Ofgem guidance setting out the expectations under the proposed obligation, DNOs either face (a) a considerable, unfunded obligation that creates no benefit for customers or (b) an unacceptable compliance risk if they assume that Ofgem actually requires a somewhat lower level of activity than it has imposed as an obligation and will assess any alleged compliance breach against this lower standard.

Without prejudice to our position that the obligation should continue to be based on reasonable endeavours, if Ofgem ultimately disagrees with the DNOs and opts to introduce a best endeavours obligation, it must include a set of exhaustive guidance specifying the actions that DNOs should undertake to meet the standard. This guidance should either be set in the licence itself, or in guidance that has the appropriate power to qualify the obligation in the licence.

If Ofgem intends that a DNO that complies with the associated PCFH guidance will be deemed to have complied with the over-arching obligation this should be made clear on the face of the licence. (DD finance annex paragraph 10.131) We note that the proposed PCFH guidance on forecasting Variable Values referred to by Ofgem is not yet available. It is essential that well-developed drafts of these obligations should be made available to DNOs as soon as possible so that they can consider how any new requirements will be implemented.

It is essential that Ofgem provides guidance on how attempts to improve the accuracy of revenue forecasts should be valued so that DNOs can make decisions regarding whether an action is or is not required in order to comply with the proposed obligation.

5. Ofgem's proposal is also inconsistent with its assumptions in other aspects of price control package.

Ofgem acknowledges that its proposed new obligation is more stringent than the current obligation. (DD Finance annex paragraph 10.127) A more stringent obligation will require additional effort by DNOs. The costs associated with these extra activities are not included in current cost base that Ofgem proposes to use to set totex allowances. As such, Ofgem is currently proposing to impost a new, unfunded obligation on DNOs.

Notwithstanding our view that the proposed change to the level of obligation should not be implemented, if Ofgem persists with this change, cost allowances must be increased to cover the costs of this additional obligation.

Consultation questions on the appropriate time value of money

FQ37. What are your views on applying a single time value of money to all prior year adjustments, based on nominal WACC?
There are good reasons for the use of different TVOM factors, as articulated in the First Economics report "RIIO-2: Prior Year Adjustments"[138]. Given the focus on the use of Uncertainty Mechanisms in RIIO-ED2, and the resulting potential for allowances to follow expenditure, companies need to know they will be compensated at the cost of capital for investing. In previous price controls, Ofgem recognised that the cost of capital requirement when investment was made in advance of revenue was the same as investment in the RAV. Our view is that the approach set out in the First Economics report remains correct, i.e. that under- and over-recoveries of revenue should use a benchmark interest rate to calculate TVOM and adjustments relating to expenditure items should use the allowed cost of capital in the calculation of TVOM. This dual true-up approach is consistent with RIIO-GD2/T2.

Question on forecasting

FQ38. What are your views on our proposed approach to using forecasts within RIIO-ED2?
Given that DNOs are required to set tariffs 15 months in advance, compared to the 3 months' notice required in Gas and Transmission, forecasting revenues is more challenging. Further, given the introduction of the forecasting penalty, and the amount of revenue at stake through Uncertainty Mechanisms, guidance documents must make it very clear how Variable Values are to be calculated, including guidance on how to make "best estimates" – for example, the stage at which any additional revenues under possible reopener applications or other Uncertainty Mechanisms should be reflected and what assumptions to make in relation to these. This will require a significant

[138] RIIO-2: Prior Year Adjustments, First Economics, 12 August 2020

amount of drafting effort from Ofgem and DNOs. Companies should then not be penalised when outcomes are different but the guidance has been followed. The guidance should also be prescriptive enough to ensure that the calculation of Variable Values is consistent across the sector.

Questions on forecasting penalty mechanism

FQ39. What are your views on the proposed charging penalty mechanism?
In relation to the proposed charging penalty, given the current levels of political uncertainty and turmoil in energy prices, coupled with the anticipated transition to Low Carbon Technologies over the RIIO-ED2 period, forecasting of demand is significantly more challenging than it has been in the past. DNOs also require further clarity from Ofgem on the next steps and treatment of costs associated with the outcome of the Access SCR. DNOs already have a licence requirement to make reasonable endeavours to recover the correct amount of revenue. We note that Ofgem is also consulting on a change from reasonable to best endeavours to ensure recovered revenue equals allowed revenue, and our response to this is set out in response to FQ36.
FQ40. What are your views on the proposed revenue forecasting penalty mechanism?
In relation to the proposed revenue forecasting penalty, the ED sector has a requirement to forecast tariffs 15 months in advance which is longer, and therefore more challenging, than the 3 months' notice required in Gas and Transmission. The removal of the two-year lag has compounded the difficulty companies will face when forecasting. We would be supportive of a more qualitative approach to ensuring forecasting accurately, where companies have to explain the reasons for differences between forecast and eventual Allowed Revenue.

Consultation question on incentive lags

FQ41. What are your views on removing lags from incentives?
We do not object to this approach in principle. Noting the interaction with the forecasting penalties and the additional difficulties this then introduces in forecasting, we welcome Ofgem's move to exclude incentive revenues from the revenue forecasting penalty.

Consultation question on baselines for ODI incentive rates, caps, and collars

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

FQ43. What is your view on fixing the potential £m 20/21 value of incentives using one number for all years, based on a forecast of RIIO-ED2 at Final Determinations (an approach similar to RIIO-ED1)?
This appears to be a pragmatic approach that would provide more certainty; however given the movement of material amounts of expenditure into Uncertainty Mechanisms this would mean ex ante Regulatory Equity is likely to be understated compared to Outturn regulatory equity if further material levels of allowances are awarded under reopeners and other UMs.

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

Consultation question on bad debts

FQ45. What are your views on our proposal to remove the Bad Debt terms from the pass-through licence condition?
The approach proposed by Ofgem seems appropriate, subject to consideration of two points: i) If the bad debt goes through the K correction factor then DNOs would also need to be able to recover the time value of money for this element. ii) Given DNOs have no control over the amount of bad debt, Ofgem would have to consider any proposed penalty term associated with the K-factor calculation due to under or over recovery. DNOs should not be exposed to a risk they have no control over.

Consultation question on revenue profiling

FQ46. Should Ofgem allow proposals to re-allocate or re-profile revenue throughout the RIIO-ED2 period and what profiles could be considered in the customers' interest?
Yes; proposals should include justification as to why reprofiling is requested. Profiles in the customers' interest may involve smoothing of bills over the price control period, increasing the notice period for the impact on customer bills, or avoiding the receipt of revenues which companies will be required to return at a later date.

ENWL Annex

2. Setting Outputs

ENWL-Q1. What are your views on the company specific parameters we have proposed for the common outputs that we have set out above?
No comment
ENWL-Q2. What are your views on our proposals for ENWL's bespoke ODIs?
No comment
ENWL-Q3. What are your views on our proposals for ENWL's bespoke price control deliverables?
No comment
ENWL-Q4. What are your views on our proposals for ENWL's CVPs?
No comment

3. Setting baseline allowance

ENWL-Q5. What are your views on our proposals for the outcome of Stages 3 and 4 of the BPI for ENWL?
No comment

4. Adjusting baseline allowances for uncertainty

ENWL-Q6. What are your views on our proposals for ENWL's bespoke UM?
No comment

5. Innovation

ENWL-Q7. What are your views on the level of proposed NIA funding for ENWL?
No comment

NPg Annex

2. Setting Outputs

NPg-Q1. What are your views on the company specific parameters we have proposed for the common outputs that we have set out above?
No comment
NPg-Q2. What are your views on our proposal to reject NPg's bespoke price control deliverable?
No comment
NPg-Q3. What are your views on our proposals for NPg's CVPs?
No comment

3. Setting baseline allowances

NPg-Q4. What are your views on our proposals for the outcome of Stages 3 and 4 of the BPI for NPg?
No comment

5. Innovation

NPg-Q5. What are your views on the level of proposed NIA funding for NPg?
No comment

SPEN Annex

2. Setting outputs

SPEN-Q1. What are your views on the values for the company specific parameters we have proposed for the common outputs that we have set out above?
No comment
SPEN-Q2. What are your views on our proposals for SPEN’s bespoke ODIs?
No comment
SPEN-Q3. What are your views on our proposals for SPEN’s bespoke PCDs?
No comment
SPEN-Q4. What are your views on our proposals for SPEN’s CVPs?
No comment

3. Setting baseline allowances

SPEN-Q5. What are your views on our proposals for the outcome of Stages 3 and 4 of the BPI for SPEN?
No comment

4. Adjusting baseline allowances for uncertainty

SPEN-Q6. What are your views on our proposals for SPEN’s bespoke UMs?
No comment

5. Innovation

SPEN-Q7. What are your views on the level of proposed NIA funding for SPEN?
No comment

SSEN Annex

2. Setting outputs

SSEN-Q1. What are your views on the company specific parameters we have proposed for the common outputs that are set out above?
No comment
SSEN-Q2. What are your views on our proposals for SSEN's bespoke ODIs?
No comment
SSEN-Q3. What are your views on our proposals to reject SSEN's CVP relating to Embedded Whole Systems Support Services for Local Authorities and its CVP relating to supporting broadband to island communities through DNO assets?
No comment
SSEN-Q4. What are your views on our consultation position to accept SSEN's CVP to protect marine biodiversity (life below water)?
No comment
SSEN-Q5. What are your views on our consultation position to accept and partially reward SSEN's CVP for personal resilience plans?
No comment
SSEN-Q6. What are your views on our proposal for SSEN's 'Energy Efficiency Accelerator for Smarter Networks' and 'Local and community flexibility market stimulation' CVP?
No comment

3. Setting baseline allowance

SSEN-Q7. What are your views on our proposals for the outcome of Stages 3 and 4 of the BPI for SSEN?
No comment

4. Adjusting baseline allowances for uncertainty

SSEN-Q8. What are your views on our proposals for SSEN's bespoke UMs?
No comment
SSEN-Q9. What are your views on our proposal for a re-opener? Do you think this is the most suitable mechanism to mitigate investment decision risks in this area?

SSEN-Q10. What are your views on our proposal for a re-opener to deal with the uncertain costs associated with Shetland? Do you think this is the most suitable mechanism to mitigate investment decision risks in this area?
No comment

5. Innovation

SSEN-Q11. What are your views on the level of proposed NIA funding for SSEN?
No comment

UKPN Annex

2. Setting Outputs

UKPN-Q1. What are your views on the company specific parameters we have proposed for the common outputs that we have set out above?
No comment
UKPN-Q2. What are your views on our proposals for UKPN's bespoke ODIs?
No comment
UKPN-Q3. What are your views on our proposal to implement a collaborative streetworks ODI-F as set out above?
No comment
UKPN-Q4. What are our views on our proposals for UKPN's bespoke PCDs?
No comment
UKPN-Q5. What are your views on our proposal to fund investment to release capacity in off-gas grid areas ahead of need via a PCD as set out above?
No comment
UKPN-Q6. Which metrics could be used for holding UKPN to account for delivery of its off-gas grid proposal via a PCD and protecting consumers by clawing back allowances?
No comment
UKPN-Q7. What are your views on our proposal for UKPN's CVPs?
No comment

3. Setting baseline allowances

UKPN-Q8. What are your views on our proposals for the outcome of Stages 3 and 4 of the BPI for UKPN?
No comment

4. Adjusting baseline allowances for uncertainty

UKPN-Q9. What are your views on our proposals for UKPN's bespoke UMs?
No comment

5. Innovation

UKPN-Q10. What are your views on the level of proposed NIA funding for UKPN?
No comment

WPD Annex

2. Setting Outputs

WPD-Q1. What are your views on the company specific parameters we have proposed for the common outputs that we have set out above?
We have significant concerns about a number of the company specific parameters. **Interruption Incentive Scheme** We have significant concerns about the approach being adopted by Ofgem in changing from the position stated in the SSMD. Our response to Core Q48 provides more details. The target setting approach proposed in the draft determination leads to targets being made tougher for frontier companies, but relaxed for companies that have poorer performance. This is illogical because companies (such as WPD) with industry leading CML performance have already adopted operational practice and investment to make improvement. There are therefore limited further opportunities to make improvements. Whereas companies that are lagging behind still have further opportunities to improve. **NARM** Not reducing the NARM target to reflect reductions in volumes in Ofgem's cost assessment is unacceptable. Our response to Core-Q54 provides more details. Applying reductions to NARM related allowances but not adjusting the associated targets introduces a hidden efficiency expectation. Through implementing changes in CNAIM 2.0 and RIGs, the industry has revised the associated metrics to remove the scope for outperformance. This means that in RIIO-ED2 there is a more direct link between activity and NARM outputs. This means that is volumes and allowances for NARM relates activities are reduced, the NARM targets should also be reduced. **Consumer Vulnerability Incentive** We broadly agree with the scope of the ODI-F and the areas of performance that will be measured. However, while we believe it will incentivise DNOs to ensure stated targets are met, we are concerned that the incentive framework does not adequately incentivise innovative thinking beyond these target areas. The framework fails to address significant disparity in performance levels between the DNOs, and in fact the targets set will perpetuate a postcode lottery in support provision throughout RIIO-ED2. While the SECV incentive in RIIO-ED1 has successfully recognised this disparity in the assessments and rewards administered, the targets now being set for RIIO-ED2 demonstrate significant differences in the value of the outcomes delivered for customers, but do not do enough to significantly close this gap between the top and lowest performing companies.

Please also refer to our response to Core-Q33. **Major Connections Incentive** We believe that the incentive should be symmetrical i.e. include a reward mechanism as well as a penalty mechanism, and include all Major Connections RMSs. This would drive good customer service across all Major Connections RMSs and customers. The sample size for the MCCSS also needs to be statistically robust. In many DNOs some RMS could provide a very small sample size, especially if that DNO had demonstrated competition in the relevant RMS. "Major connections" needs to be fully clarified in terms of "what work categories are defined as "Major Connections"". Through SQ25 we understand that it will apply to all RMSs which does conflict with the description as major connections. It is also unclear how DNOs will be compared against each other when some RMS are measured at full performance where competition has not been demonstrated against RMS with a lower scope where competition has been demonstrated. We welcome the ongoing dialogue with Ofgem with regards to the design of the Major Connections incentive. Please also refer to our response to Core Q39
WPD-Q2. What are your views on our proposals on WPD's bespoke output delivery incentives?
WPD proposed 42 core commitments as a consequence of extensive stakeholder engagement. We recognise that six of these are covered by other price control arrangements and therefore specific bespoke reporting requirements are not required. For the remainder, we proposed to track our delivery and report on progress. For this reason we proposed the majority to be ODI-Rs. We accept that reporting under SLC 50 Business Plan Commitments Reporting is the appropriate approach to keeping our stakeholders informed of progress against the 42 commitments.
WPD-Q3. What are your views on our proposals for WPD's bespoke price control deliverables?
WPD proposed two Price Control Deliverables (PCDs) within our Business Plan to recognise that there was potentially a risk of delivery of the full activity within the RIIO-ED2 period. 1. Electrification of the fleet – We are proposing to spend an additional £64 million in RIIO-ED2 to replace 89% of our small vehicle fleet with non-carbon alternatives. This will lower our annual transport emissions by 10,050 tCO2e (tonnes of carbon dioxide equivalent) in line with our commitment to become a net zero company by 2028. The delivery of this programme is dependent upon suitable vehicles becoming available. Since there is a risk that the volume could be lower we are proposing a PCD to refund allowances not used.

Ofgem accepted that end of life change was appropriate but anything beyond that was not. WPD accepts that a PCD is still appropriate but does not accept the curtailing of the ambition to electrify our fleet. This risks WPD not being carbon net zero by 2028 and thus meeting the expectations of our stakeholders who fully support this commitment. 2. We are proposing to spend £45 million in RIIO-ED2 to replace our existing telecoms system with a Private Long Term Evolution (LTE) network which provides the capability to monitor the entire distribution network from 132kV to LV and capture all the data required to support the SMART roll out. The opportunity to make this change is subject to agreements with Ofcom and should there be any delays to granting permission the programme could be delayed. Since there is a risk of not completing the programme we proposed a PCD to refund allowances not used. WPD accept Ofgem's decision not to a support a PCD for this activity. However should the programme advance far more quickly than a RIIO-ED3 start as Ofgem anticipate, it would seem sensible to have the availability of a re-opener in RIIO-ED2.
WPD-Q4. What are your views on our proposals for WPD's CVPs?
WPD went through a robust process including enhanced stakeholder engagement in order to prepare 6 CVPs (the greatest number of any DNO) in accordance with the criteria laid down within the Business Plan Guidance document. By accepting 4 of these 6 CVPs, Ofgem has clearly shown that it believes there to be important consumer benefits to be achieved from these activities. Of the 4 CVPs accepted by Ofgem, only one, CVP-5, was accepted in full with a reward. Although the feedback from Ofgem was limited the common comment for those accepted without reward was that these CVPs did not in Ofgem's view exceed minimum expectations or BAU. However, no detailed criteria were set out for how to determine whether an activity exceeded these minimum standards. In order to provide evidence to support our CVPs, and to further assess their acceptability we have employed three tests to assess whether or not the CVPs as set out are over and above the minimum requirements and business as usual: • <u>Test 1 – Exceeds Minimum Specified Obligations:</u> Is the activity in addition to or in excess of what is described as minimum in the Business Plan Guidance document? • <u>Test 2 – Represents Incremental Activity over and Above RIIO-ED1:</u> Is the activity something that was already being carried out by WPD in RIIO-ED1? • <u>Test 3 – Goes above and beyond the average equivalent activities in the Sector;</u> Do any other DNOs propose to provide the same level of service in their baseline proposals? Against these three tests the CVPs which we proposed – and in particular CVP-1, CVP-2, CVP-3 as well as CVP-5 do exceed minimum expectations and BAU functions being performed by DNOs. We believe that if CVPs are accepted then it is important they are accepted with a reward framework as set out in the Business Plan Guidance. But we equally believe such reward mechanisms must be robust and there should be no questions of

customers paying for a reward where net benefits are not delivered. Where Net Benefits are delivered customers will ultimately benefit from the delivery.

In addition to setting out a robust rewards mechanism which meets these requirements for CVP-5 we have proposed separate mechanisms for each of CVP-1 and CVP-2. The reward mechanisms proposed by WPD have been designed to go beyond what was employed by Ofgem in RIIO-GD/T2 and provide a framework that benefits and protects customers via the use of caps and collars. These mechanisms calculate total rewards based on a mix of value delivered as well as outputs delivered. WPD is committed to delivering value to our customers and strive to ensure that where a customer is paying, value is being delivered in return.

CVPs provide DNOs with the possibility of delivering real value to customers through activities which they value. Providing the correct reward package incentivising companies to identify these opportunities and then to deliver them. Not providing an appropriate reward mechanism for CVPs where it is accepted benefits are delivered, and where we have shown they exceed baseline activities, leaves potential consumer value un-incentivised and therefore, likely to be absent sufficient focus and unattained. Ofgem should therefore review its decision and apply a robust reward framework reward for CVPs 1-3 such that these value adding activities are incentivised appropriately. We continue to believe that CVP-4 and CVP-6 as we set out both meet the tests and would provide additional consumer value. We are however prepared to accept Ofgem's position on these CVPs. A summary of the CVPs, our response and the changes which Ofgem should now make at Final Determination is set out in the following table.

CVP description	Ofgem's DD position	WPD's response	Proposed Ofgem FD position
CVP-1: WPD is a net zero business by 2028	Accept with no reward: Fund through baseline with no reward	Assessed against WPD enhanced CVP criteria to provide evidence that activities are beyond minimum expectations / BAU functions. Designed and proposed robust reward mechanism	Accept with reward with agreed upon reward mechanism.
CVP-2: Help to develop ambitious LAEPs			
CVP-3: Community energy engineers			
CVP-4: Decarbonised communities	Reject: No funding or reward	Further assessed against WPD enhanced CVP criteria	Accept Ofgem position
CVP-5: Smart energy action plans	Accept: Subject to establishing a suitable reward methodology	Designed and proposed robust reward mechanism	Accept with reward with agreed upon reward mechanism.
CVP-6: £1 million 'Community Matters' fund	Reject: No funding or reward	Further assessed against WPD enhanced CVP criteria	Accept Ofgem position

Please also refer to our paper WPD RIIO-ED2 CVP Response Paper which is attached to our Consultation Letter response[139].

[139] Annex 6, WPD, Response on CVPs

3. Setting baseline allowances

WPD-Q5. What are your views on our proposals for the outcome of Stages 3 and 4 of the BPI for WPD?
WPD agrees that stage 3 represents the position that the cost submitted by WPD fall within the high confidence areas. We question whether the mechanics of Stage 4 assessment are working as the policy intended. Ofgem has promoted Stage 4 as representing a reward for companies that drive cost benchmarks. However, no rewards have been provided for any ED company, which echoes what happened in the GD&T price controls. This suggests that the opportunity for rewards under Stage 4 is unobtainable and therefore not a true opportunity for DNOs to achieve. We would expect that given that disaggregated benchmarking has companies that are ahead of median costs and Totex benchmarking has companies that are ahead of the efficiency position, that some companies would end up with rewards. This is not the case and therefore Stage 4 appear to offer a false opportunity for BPI rewards. We urge Ofgem to reconsider the mechanics of Stage 4 of the BPI

4. Adjusting baseline allowances for uncertainty

WPD-Q6. What are your views on our proposals on WPD's bespoke UMs?
We note that the three bespoke UMs that WPD proposed for load related activities have been rejected because the uncertainty is addressed by the proposed common UMs for LRE Re-opener and Volume Drivers.

5. Innovation

WPD-Q7. What are your views on the level of proposed NIA funding for WPD?
We understand that Ofgem wish to allow only 3 years of funding for NIA initially with a review during the period. This is a backwards step at a time DNOs need to innovate solutions out to 2050 as well as rolling out techniques proven in previous price controls. If this position is maintained we would request that the review of the additional two years of NIA funding happens earlier in the price control (in 2023 or early 2024) so that we can maximise the value we can extract from the total funding over the price control. Otherwise, the scope and scale of innovation that we will be able to undertake will be more limited, tending to favour projects of shorter duration and where the benefits delivery is more certain. If a dual funding approach is maintained at final determination we would ask that the criteria to be used to determine allowance be based on evidencing robust benefits management frameworks. WPD already has robust frameworks for benefits tracking in place and will enhance these further in RIIO-ED2 to encompass non-NIA/NIC/SIF

initiatives. We will also play a leading role in furthering the development of the ENA's innovation management framework (IMF) to allow for benchmarking between LNOs across gas and electricity sectors.

On the level of funding awarded we strongly disagree with Ofgem's assessment at draft determination. The assessment that WPD should be awarded only 4/5th of the amount requested was justified on the basis of not having robust benefits tracking processes in place during RIIO-ED1. This is factually incorrect. Information of the frameworks were provided within our Business Plan appendices including the Innovation Strategy and the Business Innovation and Efficiency documents. Further information and evidence is also provided in our addendums to the response to the draft determination. Benefits tracking within RIIO-ED1 based on our internal frameworks has regularly been summarised within annual RRP tables and has directly led the industry leading rollouts of solutions such as Digitalisation, ANM and DSR. The frameworks have also been used to terminate our flagship NIC project, DC Share, returning money to customers. We believe we are the only LNO to have such robust frameworks in place and are able to demonstrate their effectiveness.