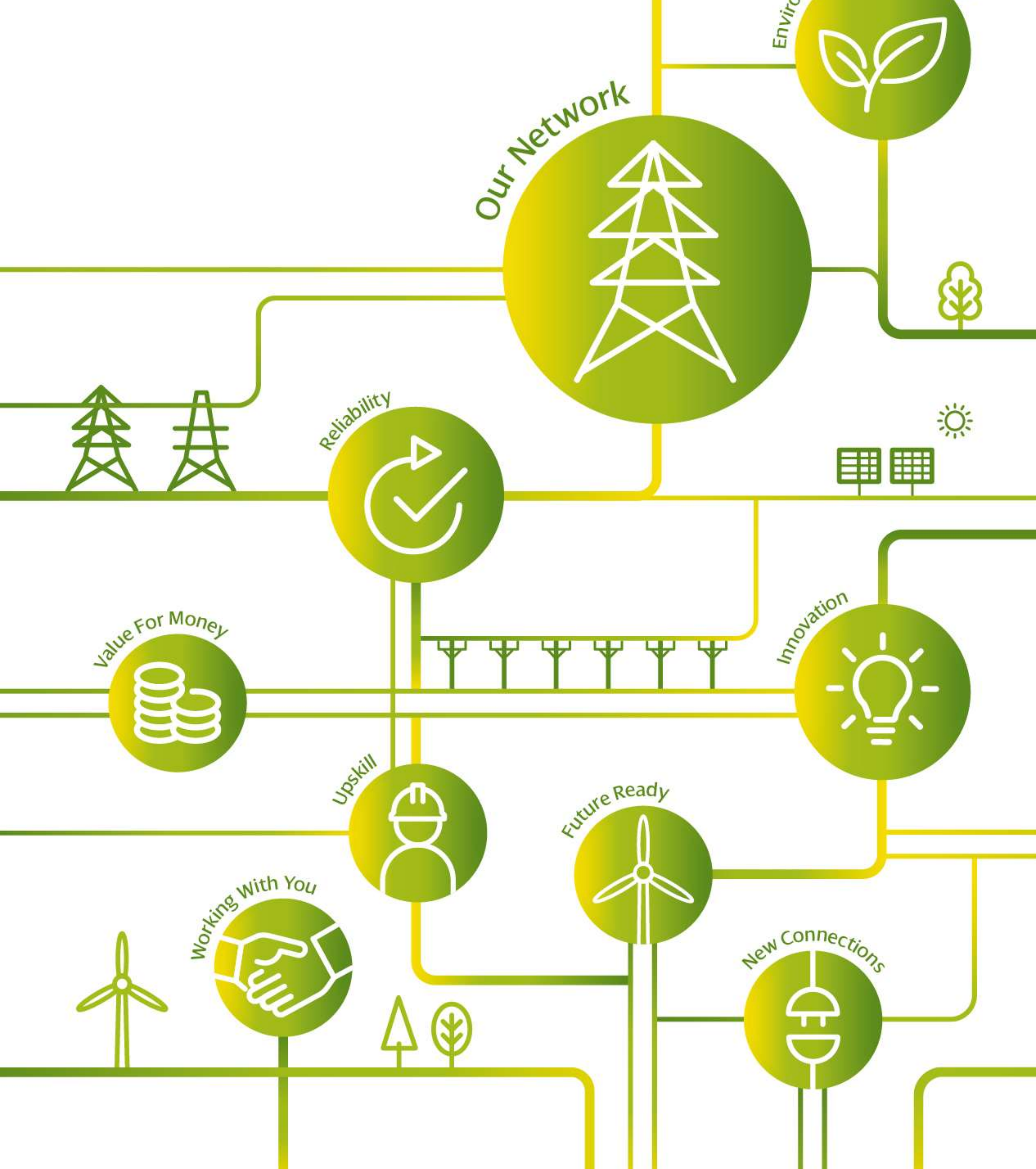
SP Energy Networks
4th September 2020

SP ENERGY NETWORKS

RIIO-2 Draft Determination Consultation Response



Structure of this document

This document has been structured as fourteen chapters with relevant questions assigned to each chapter. Each category includes an introductory response to provide, where relevant, some overarching views in response to the Draft Determination and highlight any points that have not been addressed by the Questions posed in the consultation itself. Many of the more material concerns we have are contained within this introductory text of each chapter.

A full mapping of the location for each question is detailed in Annex 1 contained within this document. The other listed Annexes below have been issued separately.

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Annexes

Chapter 1: Executive Summary

Key messages

1.1 We consider the RIIO-T2 Draft Determination to be unacceptable for SP Transmission due to:

- The returns proposed in the RIIO-T2 Draft Determination are the lowest in UK history for this sector and well below those available against comparators who are competing to attract similar investment such as the United States of America;
- This Draft Determination will not deliver the Green Economic Recovery at pace to support the UK and Scottish Government's ambition in response to the economic impact of COVID-19;
- The expenditure adjustments and nature of the uncertainty mechanisms does not provide investors with confidence and will ultimately slow down the ability for new renewable generation to be connected thus directly hindering the government's targets for Net Zero; and
- Our Business Plan created opportunities and benefits beyond only the electricity transmission network which have been removed in the Draft Determination. This is a missed opportunity to create job opportunities, economic growth across the energy sector in Great Britain, reducing the environmental impact of our operations and the subsequent health benefits that this creates through more renewable generation being connected and improved bio-diversity.

Introduction

1.2 This is SP Transmission's (**SPT**) response to Ofgem's RIIO-T2 Draft Determination. SPT holds transmission licence for the south and central Scotland. SPT is part of SP Energy Networks (**SPEN**) and the Iberdrola group. Whilst this is SPT's response to the Draft Determination, the decisions made by Ofgem as part of the wider RIIO-2 framework may have an impact on other parts of SPEN's business.

1.3 At a point in time when significant investment in the transmission network is critical to ensure the successful transition to Net Zero for Great Britain, Ofgem has impaired this objective through the Draft Determination it has proposed for RIIO-T2. Ofgem has reduced SPT's allowances through the adjustments in the Draft Determination which will be to the detriment for the connection of new generation, reducing system constraints, and ensuring we retain GB's world class network for reliability. This will impact system reliability and slow down growth in renewable generation and the adoption of other low carbon technologies.

1.4 As we write this response, we are reflecting on the announced closure of Hunterston Nuclear Power Station and the implications for the wider aging fleet across our country that will require an ability for Electricity Transmission Networks to have the headroom to cope with large uncertainty and maintain high levels of security of supply. This only demonstrates the rapid changes that our electricity transmission network needs to respond to and the need for innovative solutions as outlined in our Business Plan such as Synchronous Compensation as well as conventional reinforcement of the system as a whole.

1.5 We cannot deliver our Business Plan with the adjustments detailed in the Draft Determination. Without addressing the points identified in this response, we will have no option other than to revisit the scope of projects and operational activities we have set out in our plan.

1.6 The Draft Determination is manifestly flawed and if implemented, we are advised that it is clearly appealable to the Competition and Markets Authority, (**CMA**). However, an appeal is not inevitable, and our preference would be to work constructively with Ofgem in order to resolve these differences, thereby avoiding the need for an appeal, and, at a minimum ensure that we have worked together to properly narrow and focus the areas of dispute. We are committed to continue to work constructively with Ofgem on these matters.

1.7 In this document we set out why Ofgem's Draft Determination is wrong. We also set out the material adverse consequences that will result from its implementation. We have material concerns that, if implemented, the Draft Determination puts at risk SPT's ability to adhere to its statutory duties. We are continuing to assess this risk.

1.8 The number of errors, inconsistencies, flaws and unjustified changes to our plan have led to a complete loss of confidence in the process, the model being used and in Ofgem's decision making. It is therefore essential that Ofgem give us a revised draft determination, by early October correcting these mistakes and reversing the £15m business plan penalty, to restore confidence and faith in the process.

1.9 In the main body of our response below, we have categorised our arguments into six key areas namely,

i. Material errors in SPT's proposed total expenditure allowances

ii. Ofgem's proposed ongoing efficiency stretch is not supported by evidence and is a "double count" of SPT's embedded efficiencies

iii. Ofgem's Business Plan Incentive is based on an arbitrary assessment of low and high Confidence Costs

iv. Uncertainty & Incentive Mechanisms must be revisited to achieve Net Zero

v. Ensuring SPT remains financeable

vi. Ofgem's procedural failings

1.10 Ofgem's Draft Determination contains a range of material errors and inconsistencies. In relation to Ofgem's Totex adjustments, many of these are erroneous, overlook stakeholder support, and use a flawed benchmarking approach. Ofgem has incorrectly calibrated uncertainty mechanisms that do not adequately remunerate the costs that Electricity Transmission Owners (**TOs**) would reasonably expect to incur for generation connections, and many practical considerations have not been accounted for such as the timing of re-openers for further expenditure to be proposed.

1.11 The combination of Ofgem's proposals materially increase risks for SPT and reduce any prospect of rewards for achieving outcomes that provide demonstrable benefits consistent with our legal duties and objectives. By way of example, Ofgem have introduced the following new mechanisms or substantial changes in comparison to the existing RIIO-1 regime:

Table 1: New Mechanisms and Changes Comparative to RIIO-1

Policy Area	Risk
Business Plan Assessment	The operation of the new methodology for assessing the Business Plans, is highly subjective and penalises companies based on an opaque set of benchmarks. Also, companies are exposed to ex-post adjustments for the Business Plan Incentive through Consumer Value Propositions.
Allowed Versus Expected Returns	The creation of an adjustment to account for allowed versus expected performance which is an arbitrary and unprecedented adjustment, unreflective of future performance.
Return Adjustment Mechanisms	RAMs will cap the performance of companies and claw back any further outperformance, thus blunting TOs' incentive to find efficiencies which are then shared with consumers.
Competition Models	The introduction of three new and ambiguous competition models which will impact future large-scale investments, without any evidence of benefits to consumers.
Level of Returns	The reduction to the cost of capital to an all-time low for GB networks will not attract the necessary investment to support the UKs green recovery.

Incentives (ODIs)	A significantly reduced and asymmetric package, with a significant downside and little upside. This will incentivise "safety first" behaviour by TOs when innovation is required. It will not incentivise changes required for Net Zero and will place an unreasonable liability on TOs.
Pre-construction	New mechanisms result in greater risk being borne by TOs for pre-construction, despite the criticality of such projects being higher than ever before for Net Zero and security of supply reasons.
Large Project Delivery	A new Project Delay Charge as part of the Large Project Delivery incentive will penalise TOs for delays due to matters outside their control. This unfairly exposes companies to risks outside of their control.
Stakeholder Engagement Process	It is not clear to us that Ofgem have utilised the more complex stakeholder engagement process they have created and failed to reflect the views of the User Group and Ofgem's own Challenge Group.
Ex-Post Price Control Deliverables (PCDs)	Ofgem are suggesting that there could be an after the event adjustment to allowances if PCDs are not delivered in accordance with the Final Determination.

1.12 This response has been assured by independent subject matter experts where relevant and is accompanied by a Board Assurance Statement. In developing this response, we have participated in a number of RIIO-2 engagement sessions with Ofgem and sought feedback from our Transmission User Group and our stakeholders on the Draft Determination. This response to the Draft Determination takes account of those sessions and that feedback.

Background

1.13 In December 2019, SPT submitted its final RIIO-T2 Business Plan to Ofgem. The plan had been extensively informed by views from stakeholders as well as technical and subject matter experts. All elements of the plan were subject to thorough assurance including Board approval in addition to significant external oversight by the User Group and the RIIO-2 Challenge Group. The plan is built on our track record of accurate and careful planning, demonstrated by our delivery of our RIIO-T1 plan.

1.14 The User Group described our plan as "*an evidence-based, cost-effective Business Plan".*[1] Other comments included the following:

"*we are more than satisfied that the Business Plan provided by SPT will deliver sufficient investment to keep the system at its exceptional levels of reliability, whilst also undertaking a significant part of the work required to deliver Net Zero*"[2]

"*SPT has built a strong plan built on good principles that takes into account key stakeholder ambitions and targets.*"[3]

1.15 Ofgem's Consumer Challenge Group (CCG) was clear that SPT's plan was one of the best plans,[4] and our plan scored well. The CCG said:

"We found SPT's plan to be very accessible. Overall, we find expenditure in the SPT plan to be well justified".[5]

"The Plan takes a fairly comprehensive approach to scenario planning based upon CCC analysis. Scenarios look beyond energy to cover heat and industry and cover a range of network issues – and

[1] Independent Transmission User Group Report, SP Energy Networks RIIO-T2 Business Plan 2021-2026, page 9
[2] Independent Transmission User Group Report, SP Energy Networks RIIO-T2 Business Plan 2021-2026, page 6
[3] Independent Transmission User Group Report, SP Energy Networks RIIO-T2 Business Plan 2021-2026, page 25
[4] RIIO-2 Challenge Group Independent Report for Ofgem on RIIO-2 Business Plans, 24 January 2020, page 3
[5] RIIO-2 Challenge Group Independent Report for Ofgem on RIIO-2 Business Plans, 24 January 2020, page 36

some projects in these areas (e.g. black start) appear to genuinely go beyond RIIO-1. The Plan also proposes forward-thinking solutions (taking a strategic rather than a traditional incremental approach)".[6]

1.16 The feedback from the User group and Challenge Group provided positive feedback and we formed a reasonable expectation that our plan was viewed as high quality. The aim of the Business Plan Incentive is to reward high quality plans. The proposed penalty of £15 million was, therefore, entirely unexpected and is unjustified. We were also surprised by the proposed material reduction to our investment programme and the rejection of many of our proposals to protect the environment and the interests of consumers. If the Draft Determination is implemented, it will have material adverse consequences for SPT, and also critically, it is not in the interests of existing and future consumers; this is not consistent with Ofgem's objectives and duties.

Material errors in SPT's proposed total expenditure allowances

1.17 We believe the Draft Determination included significant errors which will compromise the interests of consumers and facilitating the transition to Net Zero.

1.18 In our Business Plan, we have only embedded those activities with the highest certainty, and criticality that require intervention in the T2 period. We proposed uncertainty mechanisms for those schemes not in our baseline plan, so that investment only takes place when their certainty increases to a point where a commitment is required. This approach is consistent with Ofgem's stated preference in the Draft Determination and is in sharp contrast to other electricity network operators' Business Plans.

1.19 For our load related investment, our high confidence baseline translated to 900MW of new transmission connections and 2027MVA of capacity to support these new connections. Whilst we are contracted to connect over 5,000MW of generation in the T2 period and create more than 8000MVA of capacity, rigorous assessment criteria agreed with stakeholders, helped us to allocate projects to our baseline or uncertainty mechanisms.

1.20 For our non-load related expenditure, we continue to utilise our high-quality asset data, in which the Ofgem engineering team told us they had high confidence, before our Business Plan was submitted. This helps to ensure we are making interventions at the optimal point in the assets' lifecycle. We have also pursued a wide range of interventions, rather than only replacement. For example, we are making far greater use of transformer refurbishment (instead of replacement) than other TOs. As a result of this, we are now replacing 0.2% of our transformer and reactor fleet in T2. For our other main asset classes, the turnover rate is largely similar, ranging between 0.2-1%.

1.21 For the management of our transformers alone, this has created a saving to consumers of £26m through refurbishment rather than full replacement in the RIIO-T2 period. It is only through our expert asset management and diligent stewardship that we can maximise the value from these assets and keep the costs of the transmission network low.

1.22 We have material concerns that the errors and adjustments made to our plan puts at risk our ability to fully meet our statutory and licence obligations as a network owner. Following our analysis, we believe that the components below make up for the differences between our Business Plan expenditure and Ofgem's Draft Determination value.

[6] RIIO-2 Challenge Group Independent Report for Ofgem on RIIO-2 Business Plans, 24 January 2020, page 186

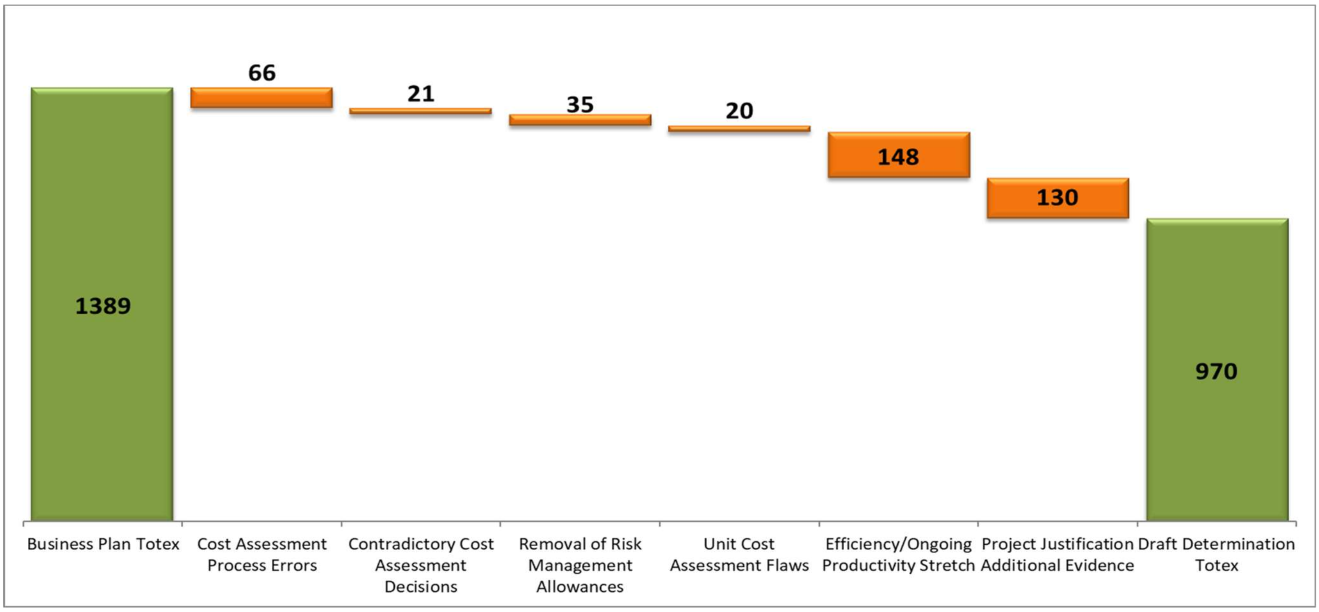


Figure 1: Waterfall Diagram of SPT's Business Plan TOTEX v Ofgem's DD

1.23 Our review of the Draft Determination has uncovered a range of errors and inconsistencies in Ofgem's cost assessment process, as illustrated in Figure 1 based on our interpretation of the values included in the Draft Determination. Some examples are as follows:

i. **Errors in the cost assessment process - £66m.** In our review of the cost assessment models Ofgem has provided us with, we have identified errors including: engineering evidence being overlooked; incorrect references to the SPT Business Plan; and reductions due to the operation of the model failing to reflect Ofgem's own guidance for completing Data Tables. All but £0.02m of a £4m project to reduce system constraints across boundary B5 have been removed which cannot allow this project to progress.

ii. **Contradictory cost assessment decisions - £21m.** Some results of the cost assessment process are impossible to reconcile with other elements of the Draft Determination. Individual projects have been approved, but the funding has been removed or reduced. For example, The Net Zero Fund is accepted by Ofgem, but its costs were removed by Ofgem's cost model (£20m). The refurbishment of Grangemouth SGT1 was approved, but its costs were removed by Ofgem's cost model (£0.57m).

iii. **Removal of risk management allowances - £35m.** Ofgem has removed 75% of allowances for risk management of our engineering projects. Projects cannot be properly conducted without an adequate allowance for risk management. Ofgem assumes that that if expenditure includes costs beyond RIIO-T2 period, there is no risk exposure in RIIO-T2. This is manifestly wrong, as risks can crystallise at any stage of a project. Ofgem assumes that the risk allowance can be allocated to elements of scheme costs proportionately and that our costs for assets already include out-turn risk. This is not correct, we informed Ofgem that our asset costs are derived from tender and contract award costs. This error by Ofgem has resulted in up to 92% of the risk allowance being removed from some schemes.

iv. **Unit cost assessment flaws - £20m.** Ofgem has applied an inappropriate means of benchmarking costs including inappropriate comparators. For example, Ofgem has used DNO costs to benchmark 33kV cable costs. This is incoherent. DNO 33kV cables are typically designed to carry one quarter of the power compared to a 33kV cable connected to a Grid Supply transformer which a TO is responsible for. The capacity of DNO cables is typically 30MVA or less which can be achieved by a single core-per-phase. TO capacities are up to 120MVA requiring four times the capacity. This immediately leads to multiples of the DNO costs being incurred and is not accounted for. This is only one example of where inappropriate benchmarks have been used to derive Ofgem's view.

v. **Project justifications have been overlooked - £130m**. Our Business Plan included 110 Engineering Justification papers to provide detailed technical evidence on our engineering plans. This was supported by contributions and a thorough review through various technical and subject matter experts to support this. These were completed in accordance with the Ofgem guidance and the majority of these have been accepted. We have submitted a well justified Business Plan. Some of our projects have been rejected on the basis of insufficient evidence despite the Ofgem guidance not specifying an engineering justification as being required. For example, costs associated with managing servitudes is expenditure we have always incurred and is necessary for the management of our assets. Yet this has been rejected on the basis of a lack of justification in our Business Plan. Engineering evidence has also been mis-construed such as the condition reports that we provided for the Torness Shunt reactor which led to these being rejected despite independent experts validating our approach. We have provided Ofgem with 22 further engineering justifications in advance of this response to support Ofgem's analysis and to continue their assessment of these areas.

1.24 In accordance with Ofgem's guidance, our Business Plan Data tables were accompanied by a detailed commentary highlighting issues we had identified where inconsistencies, omissions or ambiguities in Ofgem's guidance and glossary could lead to erroneous assessment. In many cases (in particular Network Operating Costs and Non-Load Related Expenditure), the material errors we have identified in the Draft Determination would have been avoided had Ofgem considered the relevant information submitted by us in this respect. We have seen 22% of Network Operating costs disallowed despite the reasons being cited by Ofgem for such adjustments being clearly explained in our Business Plan Table Commentary for this activity.

Ofgem's proposed ongoing efficiency stretch is not supported by evidence and is a "double count" of SPT's embedded efficiencies

1.25 We have already embedded an ambitious level of efficiency to our plan, providing £145m of savings to consumers.

1.26 Ofgem proposes an additional efficiency stretch of 1.2% per year for CAPEX and 1.4% per year for OPEX, which translates to £62m based on the Draft Determination TOTEX value. This does not, however, take into account cost efficiencies which we have already embedded into our Business Plan submission. An efficiency stretch totalling £145m was applied to our baseline plan by SPT. This comprised known efficiencies delivered through our innovation in design, increased utilisation of existing assets and other productivity improvements delivered over the course of T1 (£110m). A further 2.5% (£35m) efficiency stretch was incorporated in the RIIO-T2 baseline plan of £1375m. There is therefore a double count.

1.27 In addition, the ongoing efficiency level as proposed by Ofgem disregards the available evidence and is based on a material overestimation of productivity growth. The OBR reports that annual growth in output per worker (i.e. labour productivity) averaged around 0.3% per annum between 2008 and 2018. It is clear that productivity growth has been lower since the financial crisis. Therefore, if this value was to be applied in absence of embedded efficiencies it should be 0.3% as recommended by NERA utilising market evidence (Please see Appendix 5 for NERA's Ongoing Efficiency report).

1.28 SPT has already embedded greater efficiencies in the Business Plan. Ofgem's proposed ongoing efficiency is not supported by evidence and if retained will constitute a double count.

Ofgem's business plan incentive is based on an arbitrary assessment of lower and high confidence costs

1.29 Our plan was recognised by the Transmission User Group and Challenge Group as being high quality and offering good value. Whilst Ofgem have acknowledged the quality of the plan they have imposed a £15m penalty on SPT.

1.30 We have material concerns about the results of the Business Plan incentive. These flow, to a material extent, from Ofgem's flawed cost assessment process. In particular, Ofgem's classification of costs as "high" or "lower" confidence is arbitrary. Ofgem has disregarded clear evidence submitted by SPT justifying the confidence level in Annex 33 of our Business Plan.

1.31 Ofgem's approach lacks transparency and has the perverse result of penalising precisely the innovative and ambitious proposals that the Business Plan Incentive was ostensibly designed to encourage. For example, the rejection of our circuit ratings management system not only prevents us progressing this innovative project to increase the capacity of our network, but we are further penalised in the Business Plan Incentive as Ofgem has low confidence in their own ability to benchmark it.

1.32 There is a significant disparity between the penalties faced by gas and electricity companies as shown in figure 2. We view this as a result of the failings in the Transmission Cost assessment methodology.

Licensee	Stage 1	Stage 2	Stage 3	Stage 4	Applicable cap/collar (+/- 2% Totex)	Total Reward/Penalty (£m)
Cadent	No penalty	£0m	-£0.1m	£0m	£85.4m	-£0.1m
NGN	No penalty	£1.6m	£0m	£0m	£22.7m	£1.6m
SGN	No penalty	£0m	-£1.1m	£0m	£53.2m	-£1.1m
WWU	No penalty	£0m	£0m	£0m	£21m	£0m
NGGT	-£7.8m	£0m	-£18.6m	£0m	£31.8m	-£26.4m
NGET	-£16.7m	£0m	-£179.6m	£0m	£66.6m	-£66.6m
SHET	No penalty	£0m[132]	-£47.3m	£0m	£32.2m	-£32.2m
SPT	No penalty	£1.6m	-£16.6m	£0m	£19.4m	-£15.0m

Figure 2: Ofgem's BPI Table at Draft Determination [7]

1.33 By way of explanation Ofgem say: "*10.24. We recognise that we have assessed a significantly higher proportion of costs in the Gas Distribution sector as high-confidence costs compared to the Electricity and Gas Transmission sectors. This reflects differences between the sectors in the availability of independent cost benchmarks. The industry structure of the Gas Distribution sector makes it easier to construct independent cost benchmarks, whereas this is not always possible in the Electricity and Gas Transmission sectors.*"[8]

1.34 This is in no way an adequate justification. It penalises transmission companies solely due to the nature of their business, and strongly suggests that the design of the BPI mechanism is flawed as it fails to take account of these differences between the gas and electricity sectors. In the same paragraph Ofgem go on to say: "*However, in our BPG, we set out a number of ways in which companies can support a high-confidence assessment by providing information in their Business Plans. Alongside, other relevant*

[7] Ofgem, RIIO-2 Draft Determinations: Core Document, 9 July 2020, page 123
[8] Ofgem, RIIO-2 Draft Determinations: Core Document, 9 July 2020 paragraph 24

considerations, we have taken account of information provided by companies in their Business Plan submission in reaching our views on cost confidence".

1.35 We cannot reconcile this statement with Ofgem's assessment of our Business Plan. The SPT submission included detailed cost information designed to provide such confidence. This has been rejected for reasons that are unclear. Around 96% of our expenditure is competitively tendered and all our costs are evidence driven and based on this historic experience. The use of a discretionary high or lower confidence metric is irrational, as is the high penalty. Had Ofgem properly addressed the cost assessment process, many more of our costs would have been classified as "high confidence".

1.36 The arbitrary way in which Ofgem proposes to apply the BPI will damage trust in business plan incentives in the future. We submitted a Business Plan that Ofgem told us, before the Draft Determination was published, was well justified. We do not see how the outcome of the BPI is consistent with Ofgem's purported objective of rewarding companies whose plans are high quality.

Uncertainty & Incentive Mechanisms must be revisited to achieve Net Zero

1.37 Ofgem's proposed Uncertainty Mechanisms package will not deliver net zero and will significantly undermine government's objectives to deliver a green recovery. Any delays to the connection of renewable generation will also have a wider societal impact in terms of health benefits and economic growth.

1.38 Our Business Plan addresses the very material consequences of Net Zero for electricity transmission. It focusses on the interests of present and future consumers in the reduction of electricity related emissions of greenhouse gas and the need to contribute to sustainable development. These are all matters that Ofgem is under statutory duties to address. We provided a range of progressive and structured mechanisms for this purpose in our Business Plan, but the Draft Determination does not provide sufficient flexibility or remunerate the costs that we would expect to incur.

<u>Inadequate Uncertainty Mechanisms to support customers' needs</u>

1.39 Our Business Plan proposes uncertainty mechanisms to ensure that when the need for investment crystallises, the funding is approved timeously and efficiently. This need for investment is critical for the transition to Net Zero - to ensure generation is connected in a timely manner, capacity is available for the transmission of power, and the increasing demands for electricity can be met.

1.40 Over the RIIO-T2 price review period, we are contracted to connect over 5000MW of renewable generation, 4100MW more than our baseline plan, which would make an annual saving of more than 3 million tonnes of CO_2 per annum. We only included expenditure proposals in our Business Plan for projects which we had a high confidence would materialise in RIIO-T2. To ensure that currently less certain projects could progress without undue delay, we proposed several uncertainty mechanisms to provide allowances when such projects became more certain. This approach was supported by stakeholders and our User Group.

1.41 During the development of our Business Plan, we engaged with Ofgem on numerous occasions about the design of our proposed mechanisms. Despite this positive engagement, Ofgem has proposed different mechanisms with no clarity as to why our proposals were dismissed. It is unclear how Ofgem assessed the merits and drawbacks of our proposals compared to their own. SPT will be underfunded by £90m if we are to connect the additional 4100MW of generation through the mechanism proposed in the Draft Determination.

1.42 Ofgem has rejected these mechanisms without giving clear reasons and has substituted its own mechanisms. The mechanisms are poorly designed and will likely materially delay projects that are critical to the achievement of Net Zero. Ofgem's proposed mechanisms will not provide adequate funding and contain basic errors. For example, the regression analysis to inform the connections volume driver is based on eight data points out of a total of fifty that we have provided to Ofgem. This is neither statistically robust nor does it provide a representative sample of projects that we may be required to deliver. Further, the models include errors in their operation which creates flawed results.

1.43 The uncertainty mechanisms proposed by Ofgem will create a range of practical difficulties. Ofgem has proposed a 2024 reopener window for several areas under the Medium sized investment project re-opener (MSIP) to cover projects such as those required by the ESO to reduce network constraints. There is a single 2024 application window proposed for such projects to be considered. This will delay any project from progressing in the interim. This will likely materially delay projects that are critical to ensure that the GB transmission system remains fit for purpose so that reasonable demands for electricity are met, the electrification of transport and heating can be supported, and for wider Net Zero purposes. We have proposed that this mechanism should provide an annual re-opener to overcome these risks.

1.44 Other Ofgem objectives and duties will also be impacted by this approach and will negatively affect stakeholders and consumers. The delay to low carbon generation projects creates security of supply issues, will damage competition in the electricity generation market and may affect competition in the upcoming CfD allocation rounds. More generally, the Draft Determination proposals for uncertainty mechanisms do not promote long-term efficiency, create the risk of increased costs for consumers, and provide less certainty for TOs.

The Draft Determination dilutes the successful RIIO-T1 incentive regime

1.45 The proposed ODI package represents a significant dilution of the incentives package which underpins the RIIO model, with penalties three times greater than the potential rewards.

1.46 There are stark differences in the incentives proposed in the Draft Determination between gas and electricity transmission companies. Figure 3 below shows that in gas, the incentive regime is more symmetrical and provides substantially greater upside potential compared to electricity transmission, where companies are more likely to face penalties with little opportunity of reward.

1.47 In RORE terms, Common ODIs Upsides for GDNs (0.4%) are double that of electricity transmission (0.2%) average. Further, the downside risk of 0.8% for GDNs is 28% lower than for TOs who face a 1% downside on average. We cannot identify a sound reason for these stark differences.

1.48 SPT (and RIIO-ET2) incentives are downwardly biased, due to a negative skew towards penalties and a greater magnitude of the negative skew relative to the approach taken in other sectors. Ofgem proposes penalties 4 and 4.5 times higher than rewards for SPT and ET2 respectively, which is considerably greater than penalties for energy networks in RIIO-1 (penalties 1.1 times higher than rewards, i.e. almost symmetrical on average) or water companies at PR14 (penalties 2.6 times higher than rewards) and PR19 (penalties 1.5 times higher than rewards), as illustrated below.

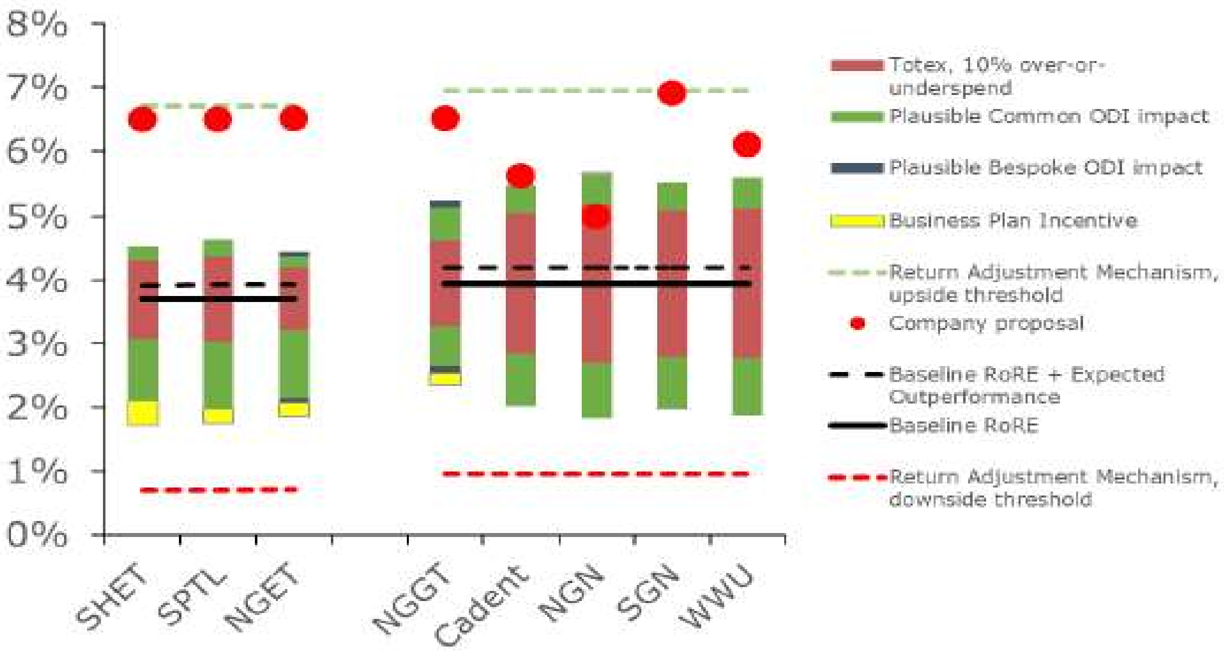


Figure 3: Ofgem's RORE Values at Draft Determination[9]

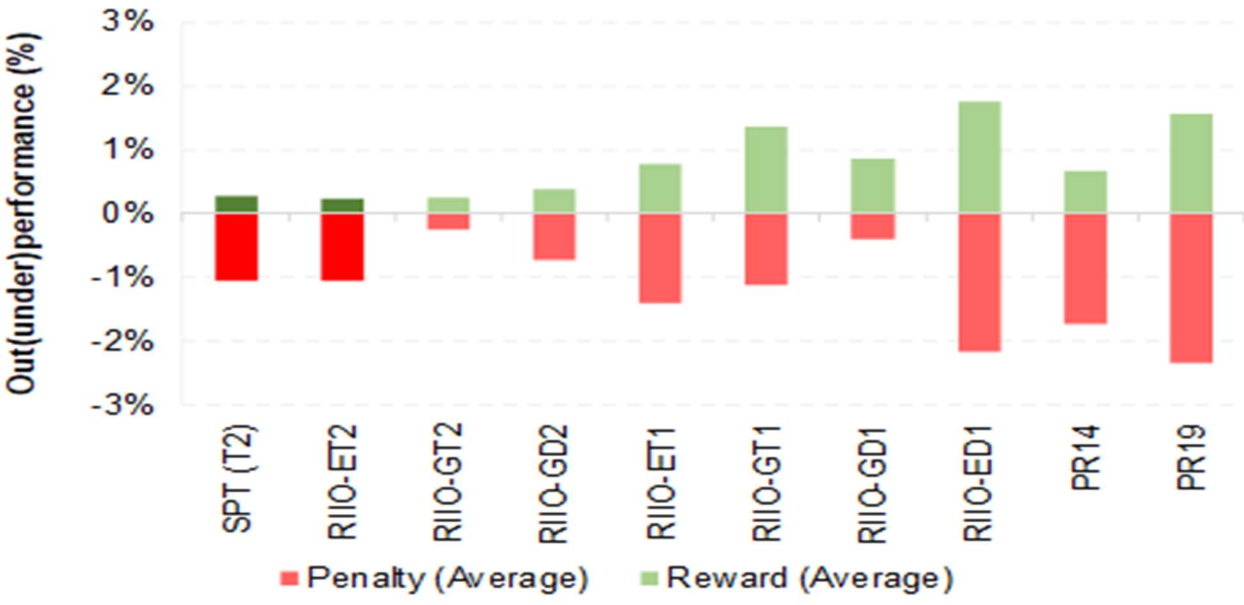


Figure 4: Ofgem's Proposed Asymmetry of Incentive Package for SPT/RIIO-ET2 Is Unprecedented Relative to other UK and historic Regulated Networks

1.49 Ofgem has not yet specified the full range of the output incentive package for the RIIO-T2 period, but from the available ODI information, we forecast (bottom up) that the output incentive range has a downside risk of £12.3m and a maximum upside opportunity of £2.3m per annum. This is compared to a downside of £12.7m and upside of £12.9m for the RIIO-T1 period. This asymmetric risk imposes an unreasonable liability on TOs. The extent of this asymmetric outcome is unprecedented in GB regulation and presents a risk that will undermine investor confidence. Ofgem itself indicates the proposed range could be at 105bps downside and 27bps upside of RORE which translate to c. -£61.8m to +£15.6m over the price control, therefore we

[9] Ofgem's Investor Presentation 9th July

believe there is potentially an inconsistency between Ofgem's RORE ODI ranges and the bottom up incentive calibration.

1.50 The User Group said of our proposed incentive package: "*We believe incentives have made a real and measurable difference in the performance of network companies, including SPT. We support their continued and targeted use in RIIO T2. SPT's proposal builds on experience in T1, enveloping feedback from RIIO T2 engagement, including input from the User Group. We agree that it is a strong package with excellent new additions*."[10]

1.51 Each of our proposed ODIs are supported by customer and stakeholder feedback we have received and used as the basis for our ODI proposals. However, Ofgem has rejected all but one (a reputational one) of our bespoke ODI proposals despite the clear evidence we have submitted[11] to demonstrate all ODI proposals fulfil the criteria set out in Ofgem's September 2019 RIIO-2 Business Plan Guidance[12]. We have demonstrated the positive net present value (NPV) and consumer value proposition (CVP) that each of our financial ODI brings.

Ensuring SPT remains financeable

1.52 In our view, Ofgem's proposals undermine the financeability of electricity transmission by cherry picking arguments. Ofgem have made arbitrary adjustments and fail to reflect fundamental differences in asset betas and risk associated with electricity transmission in comparison to water.

1.53 As a more general point, Ofgem's Cost of Equity proposals are divorced from the real world and do not represent the reality faced by investors. The lack of adequate incentives to investors to commit to crucial investment in the UK and create the required stimulus to enable Net Zero can be evidenced by recent investor news, for example on the 27th August 2020, Barclays published an investor note which stated it would expect National Grid to trade at a 5% discount to RAB based on the proposed Draft Determination parameters. On the same day, S&P have affirmed they had changed National Grid plc's outlook to negative, the key reasons for the negative outlook are the impact of Covid-19 and tougher conditions in the next regulatory period in the UK. As the UK is due to leave the EU within the next 3 months, we believe this will introduce even further risk which has not been factored into Ofgem's academic use of the CAPM.

1.54 Ofgem's proposed finance package does not reflect the increased level of risk that TOs are exposed to, benchmarks poorly with other comparators and includes unjustified adjustments. Predictability and reasonable returns are essential when, now more than ever investment is required in the UK to meet GB's Net Zero objectives. The financial package must be fair to consumers and investors. Fairness to consumers and fairness to investors are not and should not be mutually exclusive, and Ofgem has a duty to balance these objectives. It is in the interests of consumers that utilities can attract the necessary finance. The interests of future consumers is of particular relevance here. Setting an unduly low cost of capital may be viewed, (erroneously) as in the interests of present consumers. However, Ofgem's proposals will damage confidence in the regulatory regime and therefore risks leading to a higher cost of capital in the future. This is manifestly not in the longer-term interest of consumers.

1.55 It is also important to ensure the UK can attract the necessary investment and companies retain their investment grade credit ratings. Ofgem's cost of equity allowance for Electricity Transmission lies below the median of European countries and on an international basis is much lower when compared to the returns available in the US.

1.56 Ofgem's proposed cost of equity puts at risk the significant investment required to ensure network companies can enable the transition to Net Zero as quickly as possible. Worryingly, Ofgem's Draft Determination does not provide adequate signals to investors to commit to the UK and create this stimulus.

[10] User Group Report, page 37
[11] Appendix A: *BESPOKE FINANCIAL ODI CHECKLIST* of Annex 12 of our December 2019 submission https://www.spenergynetworks.co.uk/userfiles/file/RIIO-T2_Annex_12_Output_Delivery_Incentives.pdf
[12] https://www.ofgem.gov.uk/system/files/docs/2019/09/riio-2_business_plans_guidance_september_2019_-_published_0.pdf

1.57 It is imperative that Ofgem set an appropriate Cost of Equity to avoid a similar situation to 1999, where water companies were trading at a large discount to their RAV, due to a market perception of a tough regulatory settlement. It is not in consumers' interests to damage companies' financeability.

Ofgem's view that water companies face similar risks to TOs is wrong

1.58 Water companies are less risky than electricity networks as evidenced by historic asset betas, yet Ofwat has proposed a Cost of Equity for PR19 that is more than 20bps higher than Ofgem's current proposal. Ofgem's proposed finance package does not reflect the increased level of risk that transmission owners are being exposed to, and benchmarks poorly with other comparators. Ofgem argues that pure-play energy networks in GB have several similar risk characteristics as pure-play GB water networks, suggesting that Severn Trent (SVT) and United Utilities (UU) are appropriate comparators for estimating betas for pure play GB energy networks. However, Ofgem's economic advisors, CEPA, in its own report acknowledges that there are some different sector specific drivers of risk that could imply a higher risk for energy networks.

1.59 Both qualitative and quantitative evidence demonstrates that TOs face greater risks than water companies. Whilst the regulatory regimes in energy and water are closely aligned, NERA's comparative risk analysis suggests that investors in SPT face higher risk than investors in water networks (and indeed other energy networks) for the following reasons:

- Empirical data supports persistently higher betas for energy networks (NG, SSE) compared to the water companies (UU, SVT, PNN), suggesting higher risks for energy networks than water companies. National Grid's asset beta is around 0.38 on average higher than water networks.
- Greater system operability risks associated with TOs;
- Greater use of competition models with unknown policy from the outset of RIIO-T2 (further detailed below).

RIIO-2 framework has deteriorated from a risk perspective

1.60 Investors face greater risks under RIIO-2 rather than the RIIO-1 regime, and this is supported by rating agency comments on the riskiness to the regime. Although Moody's maintain its Aaa sub-rating for the stability and predictability of the regime, Moody's recently announced that the framework has deteriorated, as such is credit negative[13], notably given Ofgem's reduction to the allowed return for assumed outperformance. It is of utmost importance to note that investors alike have raised their grave concerns at Ofgem's Draft Determination proposals. Bernstein in its open letter to Ofgem's CEO[14] has stated that "*Network investments can create much needed economic stimulus as well as enabling UK to achieve its Net Zero goal, but the Draft Determination is stuck in "austerity" mode*". It also correctly recognises that Electricity transmission, "*which has been granted the lowest RoE (3.7%), faces the highest disallowance (46% of proposed spend disallowed)*".

1.61 Predictability and fair returns are required at a time where, greater than ever, investment is required in the UK to facilitate GB's Low Carbon Agenda. As a UK based company, we are not only creating employment opportunities, but are also supporting our local economies as a responsible and transparent taxpayer.

[13] Moody's Investor Service: Sector Comment Regulated Energy Networks – UK RIIO-2 proposals support sector's business risk profile, but legitimacy in greater focus 3 August 2020
[14] Bernstein (2020), "An Open letter to the CEO of Ofgem: With great power comes great responsibility ..."

Ofgem's Cost of Debt model is untested and introduced at a time of existing financial uncertainty

1.62 Ofgem propose to update their Cost of Debt index to the iBoxx Utilities 10yr+ index, instead of the average A and BBB 10yr+ iBoxx non-financial indices used in RIIO-1. This is an untested debt index and therefore introduces further risk from unknowns. For example, compared to iBoxx A/BBB, iBoxx Utilities is sector specific and does not have a defined rating (other than investment grade), whereas iBoxx A or BBB indices are regularly updated to include only A or BBB bonds respectively. This imposes a risk of under-recovery of Cost of Debt if the Utilities index credit rating improves over RIIO-2 due to the fact it does not have a defined rating.

Lack of robust financeability assessment

1.63 Ofgem have conducted an "in the round" assessment of financeability for the RIIO-2 period with the focus very much on the debt finance of a notional company and very little regard to actual company parameters or the financeability of equity. This is at odds with the analysis that companies were instructed to provide along with their Business plan submissions.[15] The impact of an "in the round" assessment on individual ratios and the importance placed on them by external parties, such as investors and credit ratings agencies should not be ignored.

1.64 Ofgem needs to reflect, the potential scale of expenditure that may be required via reopeners, through its stress testing of financeability. The output from financeability stress testing needs to demonstrate the company can maintain a comfortable investment grade rating, after funding all reopeners, to continuously comply with its licence and facilitate the raising of additional funds as required.

1.65 Furthermore, Ofgem's analysis fails to cover the financeability of the actual companies, the impacts to cash flows resulting from the RIIO-T1 close out process or how the proposed changes to annual price control mechanisms (i.e. AIP). Ofgem have also made adjustments to the assumptions around the financial structures of the notional company which have drastically improved the implied credit ratios but do not reflect the real-world characteristics of companies. An example of this is increase in the assumption of CPIH index linked debt from 25% to 30% based on an average of the network operators. The disparity between companies is wide with some companies such as SPT holding no index linked debt whereas others such as NGET hold higher levels than the average. Another example, is the adoption of the aforementioned new index for the Cost of Debt which could have a detrimental impact on the financeability of Network companies, as currently the new index does not reflect a similar credit quality of the network operators.

1.66 The arguments for providing a lower level of gearing from Ofgem was to take account of the higher level of risk involved with the delivery of the required Totex in the regulatory period. It is inconsistent not to recognise this through a higher cost of equity. It is a highly plausible scenario that shareholders in the electricity transmission sector, after consideration of the scale of reduction in cost of equity, would prefer a higher notional gearing, above the 55% reflected in the draft determination, if the WACC will remain unchanged at a higher gearing and therefore reduce its commitment equity with no impact on the WACC.

1.67 The views of Credit Rating Agencies must also be taken on board, Moody's for example have recently commented "Social risks have, however, become evident, with the regulator diverging at the margin from established practice following criticism. Ofgem's new outperformance wedge for the forthcoming RIIO-2 price controls will reduce allowed equity returns and weaken adjusted interest coverage ratios.[16]" These changes represent a departure from established regulatory practice, adherence to which has supported widespread confidence in the stability and predictability of the regime.

1.68 Pressure on metrics will be exacerbated by the impact of the COVID-19 pandemic which should not be ignored due to the longer-term impact this could have on the wider economy, notably on inflation. Ofgem's stress testing of financeability needs to reflect the cash collection risk, which Ofgem propose will be passed

[15] RIIO-2 Business Plan Guidance 9 September 2019
[16] Moody's Investor Service: Sector comment Regulated Energy Networks – UK, RIIO-2 proposals support sector's business risk profile, but legitimacy in greater focus – 3 August 2020

to the TOs in T2. Revenues of regulated energy networks and the value of their assets are directly linked to an inflation index, exposing them to the risks of low inflation. Debt also typically bears fixed rates of interest, which effectively increase in such a scenario. Prolonged low inflation would therefore lead to a relative reduction in cash flow and a weakening of a network's financial profile, a credit negative. Networks in GB are vulnerable to low inflation scenarios due to the regulatory funding model i.e. real return based on an inflation based RAV. This model leads to a "Cash flow gap" as the Nominal interest debt raised by Networks are paid down by a real return with the Inflation proportion added to RAV and paid over time. The lower the inflation, the weaker the asset base on which to borrow.

1.69 Furthermore, the inclusion of Expected v. Allowed related cash flows in the financeability assessment is flawed. This is due to the fact that there is no guarantee that the cash flows from this adjustment will be received during the period. Ofgem has proposed an ex post true up mechanism however the proposal is not company specific and would be applied on an electricity transmission sector basis therefore it is plausible that SPT could end up in a scenario where the intended return is not realised and no true up would be implemented.

Ofgem's CAPM estimations 'Cherry Pick' financial theory

1.70 Ofgem's methodology for estimating the CAPM's individual parameters contains numerous errors. Ofgem has not properly addressed the issues raised by stakeholders, in relation to their evidence base in the Consultation. For example:

i. CEPA's Dividend Growth Model, a key component of Ofgem's cross-checks, understates the expected TMR, due to implausibly low assumptions around dividend growth. It is also clear that the level of returns indicated by Ofgem's proposals do not reflect the risks faced by network companies as mentioned above.

ii. Ofgem's reliance on an alternative historic inflation series understates the expected real TMR as it overstates historical inflation. The inflation series is based on back-cast data which the ONS consider to be unreliable

1.71 Ofgem have also committed to departing from the well-understood and longstanding regulatory practice of selecting the upper end of a cost of equity range. This has been supported in a number of ways, including academic research, which has found that aiming up, well above the central estimate, is likely to minimise the expected losses to society from underestimating the regulated business's true cost of capital.

1.72 In relation to Ofgem's proposal to introduce an "Allowed v Expected" adjustment to the CAPM Cost of Equity parameters, we consider that this is an arbitrary adjustment, which must be removed from Ofgem's Cost of Equity proposals. Historic outperformance cannot be a guide to future outperformance within a newly calibrated and significantly modified (and highly asymmetrical) incentive regime. This proposal goes against the past stability and predictability of the WACC-setting process, which is fundamental in the UK regulatory model and has aimed to maintain investor confidence. It is also clear that Ofgem has clearly departed from the existing incentives regime, so historic performance will most certainly not be reflective of the future performance in RIIO-2. In addition, we believe the data which its behind Ofgem's adjustment is incorrect.

1.73 Ofgem's proposals undermine the stability and predictability of the WACC-setting process, which is fundamental to the UK regulatory model. This undermines investor trust and confidence.

1.74 A further Ofgem error is that Ofgem repeatedly gives insufficient weight to cogent evidence that points to a higher cost of equity whilst giving undue weight to less cogent evidence that points to a lower cost of equity. As an example, Ofgem give excessive weight to evidence about OFTO IRRs, and investor forecasts. In adopting this approach Ofgem falls into error. We would also highlight that Ofgem has not been able to share the relied upon OFTO evidence with companies as it has advised this data is confidential.

Ofgem's competition models introduce further uncertainty for investors and have not yet demonstrated benefit to consumers

1.75 We continue to support the role of competition in electricity transmission, but only where it can clearly demonstrate benefits and value for consumers. Ofgem's proposed competition models have not yet demonstrated consumer value.

1.76 We are actively involved in the ESO's development of its Early Competition Plan. The 'early' CATO model is the only competition model proposed by Ofgem which could potentially deliver actual competition. The 'late' CATO model whereby the TO would be responsible for design, planning and consenting of the project adds little or no value to consumers and will contribute to delays in the delivery of major infrastructure, as a result of planning, tendering and other process issues, resulting in material costs to consumers and increased greenhouse gas emissions.

1.77 Both 'early' and 'late' CATO models require primary legislation to implement. Ofgem must act within the current legal framework in extending competition in electricity transmission. Ofgem's proposals constitute material changes and, as such, Ofgem should wait until Parliament has scrutinised any reforms and passed the required legislation.

1.78 Due to the lack of Parliamentary time, Ofgem has proposed two other models which it states do not require legislation. The first model, the "Special Purpose Vehicle" or "SPV" is unlawful, as we have explained in various submissions.[17] The second model, the "Competition Proxy Model" or "CPM" is materially flawed.[18] Ofgem's own recent assessments of the application of CPM to the Hinkley-Seabank and Shetland Projects demonstrate no benefit to present and future consumers.[19] Both models are materially under-developed. They should not be introduced as part of RIIO-T2. This is clearly a significant area of unknown policy and introduces further uncertainty for our investors given the scale of investment associated with the relevant projects which could be tendered.

Ofgem's process

1.79 Whilst we recognise COVID-19 will have impacted Ofgem, RIIO-T2 has been characterised by significant procedural difficulties and flaws. We have however observed this through the development of the Business Plan guidance as well as the Draft Determination.

A lack of clear and timely guidance on the assessment of the Business Plan

1.80 Before we submitted our Business Plan, Ofgem confirmed the critical role of the User Group and Challenge Group. These were to be a key element of Ofgem's assessment of Business Plans. However, the terms of the Draft Determination suggest that the reports issued by the User Group and Challenge Group have been discounted. Indeed, Ofgem seldom mentions the work of the Groups in the Draft Determination.

1.81 We have serious reservations about various aspects of Ofgem's conduct of RIIO-T2. Ofgem's guidance for preparation of the Business Plans was finalised just over a month before the plans were due to be submitted. There has been no meaningful consultation on the cost assessment process, which is materially flawed and is detailed in our response to the totex adjustments.

[17] See for example "Extending competition in electricity transmission: commercial and regulatory framework for the SPV Model Consultation" SPEN, 9 November 2018. Available here.
[18] See for example SPT's response to Ofgem's 2018 consultation on Hinkley-Seabank (March 2018); SPT's response to Ofgem's consultation on extending competition in electricity transmission (November 2018); and SPT's response to Ofgem's updated minded-to position for Hinkley-Seabank delivery model (November 2019).
[19] "Hinkley - Seabank: Updated decision on delivery model", Ofgem, 22 May 2020. Available here. "Shetland transmission project: Decision on Final Needs Case and Delivery Model", Ofgem, 30 July 2020. Available here.

1.82 Our Business Plan had to comply with Ofgem's Business Plan Guidance (**BPG**). The first draft BPG was published on 21 December 2018. Updated versions were published on 3 June 2019 (less than one month before companies had to submit first drafts of their Business Plans to the Groups) and 9 September 2019 (less than one month before companies had to submit their second drafts to the User Group and Challenge Groups). The final version of the BPG was not published until 31 October 2019, just over one month before the final submission date for the plans and after the companies had already submitted two versions of their plans to the User Group and Challenge Groups.

1.83 Material elements of Ofgem guidance were provided very late in the process. For example, Ofgem's expectations on CVP proposals were not set out until the September version of the BPG. Ofgem also published other key documents very late in the process, including the final Business Plan Data Templates in September 2019.

Draft Determination assessment

1.84 Ofgem justifies the rejection of our proposals on the basis that SPT did not provide sufficient evidence. We submitted our Business Plan following a high-quality assurance process, and thorough scrutiny by the User Group and the Challenge Group. In the run up to the Draft Determination senior Ofgem personnel assured us that our plan was well justified. On this basis alone, we find the rejection of our proposals surprising.

1.85 After we submitted our Business Plan Ofgem had ample opportunity to ask us for further information. However, there are many examples where Ofgem has rejected our proposals without having raised questions through the supplementary question process. To address this issue as best we can, and in advance of this consultation response, we have provided Ofgem with 22 updated or additional justification papers and accompanying evidence.

1.86 Ofgem has rejected a wide range of our proposals without providing clear reasons. In some cases, no reasons are provided.

Transparency during the Draft Determination Consultation

1.87 Ofgem published the Draft Determination on 9 July 2020 with a deadline for response was 8 weeks later, on 4 September 2020. The Draft Determination cannot be fully understood without access to various Ofgem models. These were only made fully available by Ofgem on 24 July 2020, two weeks after the publication of the main document. SPT has asked Ofgem a range of questions about the Draft Determination since 9 July 2020 with many of these responses not being received until two weeks before the deadline for submission.[20]

1.88 Against that background we will continue to review the Draft Determination after 4 September 2020 and reserve the right to make further submissions to Ofgem on any other areas of concern we identify. It is of paramount importance that SPT and the other network companies have sufficient time and opportunity to ventilate – and that Ofgem listens to - issues that we identify in this response and subsequently in the Draft Determination prior to Ofgem's Final Determinations being published.

[20] We also note that, after the publication of the DD Core Document, Ofgem added an additional question (Q17) "*What are your views on including the delivery of outputs such as: CAF outcome improvement; risk reduction; and cyber maturity improvement, along with projects-specific outputs*?" Ofgem did not communicate to SPT that such a question had been added to the consultation.

Licence drafting being developed in advance of policy being determined

1.89 In parallel to the Draft Determination process, the licence drafting for RIIO-2 is ongoing. However, until further clarity and analysis has been provided on the various price control instruments, such as the Licence, Financial Handbook and Price Control Financial Model (PCFM), a full understanding of the wider impacts cannot be achieved. In addition, we have been advised by Ofgem that there will be a 4 week consultation period to consult on the full T2 draft licence next month. Such timescales will not provide licensees with sufficient time to review these conditions in full so as to undertake the required analysis and due governance.

Conclusion

1.90 We have serious concerns over the proposals set out in the Draft Determination.

i. The totex adjustments contain material errors that require to be addressed and inconsistencies which impact our plans. Material evidence we have provided has been disregarded or overlooked.

ii. Ofgem's proposed ongoing efficiency stretch is not supported by evidence and is a "double count" of SPT's embedded efficiencies.

iii. The Business Plan Incentive is flawed and relies on an arbitrary adjustment. It is not reflective of stakeholder views of our Business Plan.

iv. Uncertainty Mechanisms and incentives (ODIs) fail to provide adequate protection to TOs and do not create an attractive package which will ultimately hinder the UK's ambitions for Net Zero.

v. Ofgem's proposed finance package does not reflect the increased level of risk that TOs are exposed to, benchmarks poorly with other comparators and includes unjustified adjustments.

vi. The process followed by Ofgem has had serious failings which has compromised our ability to respond to the Draft Determination and lacked transparency.

1.91 The Draft Determination ignores the views of stakeholders, and more specifically the User Group and the Ofgem Challenge Group.

1.92 Without a Final Determination addressing the points identified in this response, we will not be able to deliver our Business Plan and we will have no option other than to revisit the scope of projects and operational activities we have set out in our plan. Nevertheless, given the depth of the cuts to our expenditure allowances proposed by Ofgem, we have started the process of identifying the consequential adjustments that would enable us to meet Ofgem's requirements. This leads to the inevitable conclusion that complying with the Draft Determination will produce consequences that Ofgem previously sought to avoid. The Draft Determination contains an implicit, material and un-signalled change in Ofgem's approach to key issues. Some examples are as follows:

i. **Jobs -** In the Sector Specific Methodology Decision Ofgem said, "Resilience also depends on companies having sufficient people with the required skills needed to design, build, operate, maintain and repair their networks." We agree. We believe it is critical to enhance workforce resilience in the RIIO-T2 period. This has become even more essential in light of the UK's current economic downturn caused by COVID-19. For example, our plans include the recruitment of graduate trainees and apprentices. However, in the short run such recruitment is not absolutely necessary. Accordingly, we are now forced to review these plans.

ii. **Net Zero -** In the Sector Specific Methodology Decision Ofgem said: "7.3 Alongside these responsibilities, the gas and electricity networks also need to mitigate their environmental impact through their own business activities. In our Business Plan we proposed a range of measures to reduce the carbon footprint of our business. Ofgem's signals in the Draft Determination are that these measures are not necessary in the short run. We are therefore having to carefully review whether we can progress these initiatives in light of the proposed cuts to our expenditure required by Ofgem.

iii. **Outputs -** 96% of our expenditure is competitively tendered therefore the option to reduce costs without re-scoping activity is very limited, noting that despite the cost reductions applied, Ofgem's engineers have agreed the scope on all but a handful of our projects. We have analysed the reductions and the bearing that these would have on our Business Plan. If these are to continue at Final Determination, we will have no option other than to revisit the scope of projects and operational activities we have set out in our plan.

1.93 More generally we cannot reconcile the Draft Determination with the wider objectives of a "Green Recovery". Expenditure proposals that are manifestly required to achieve Net Zero have been rejected. These are proposals that could strongly support a Green Recovery on a low or no regrets basis. This is also at odds with the long-term approach taken by other sectors, for example Ofwat were one of the signatories on an open letter which pledged that "Government and water regulators will facilitate water companies to accelerate planned investment, bring forward future investment and implement new ideas to boost the economy". Ofgem's approach is out of line with this policy objective.

1.94 Our industry must be utilised as a catalyst for supporting businesses indirectly and job creation in addition to directly keeping our communities in employment. However, Ofgem's Draft Determination does not provide adequate signals to investors to commit to the UK and create this stimulus.

1.95 Ultimately, the Draft Determination is manifestly flawed and if implemented, we have been advised that it is clearly appealable to the CMA. However, an appeal is not inevitable, and our preference would be to work constructively with Ofgem in order to resolve these differences, thereby avoiding the need for an appeal, and, at a minimum ensure that we have worked together to properly narrow and focus the areas of dispute.

1.96 We have provided a comprehensive response to the Draft Determination Consultation which we trust provides a constructive perspective, along with additional evidence to support our arguments. Throughout the development of our RIIO-T2 Business Plan we have sought to work constructively with Ofgem and are committed to do so in the months ahead as the Final Determination is prepared.

Chapter 2: Expenditure and Outputs

Introduction

2.1 A 30% reduction in Totex results in an unacceptable position for the development and operation of the transmission system in the south of Scotland. As presented in the Draft Determination, the Totex reductions will impact the growth of renewable generation, significantly reduce the reliability of electricity supplies and impact the green recovery by putting at risk our plans to give over a hundred prospective employees the opportunity to join us in facilitating the drive to Net Zero.

2.2 The proposed Totex allowances set by Ofgem in the Draft Determination will not fund SPT to complete the scope of works presented in the Business Plan, compromising our ability to meet our licence obligations. The cost reductions that have been applied by Ofgem are the result of flawed assessment techniques and inadequate assurance of Ofgem's proposals (which is commented upon further below in more detail). The erroneous removal of costs for necessary projects, if not restored at Final Determination, would compromise SPT's ability to comply with Standard Licence Condition B12 with respect to making available its Transmission System and ensuring that it was fit for purpose. SPT's ability to fulfil its obligations under the Electricity Safety, Quality and Continuity Regulations 2002 with respect to ensuring that equipment is used and maintained as to prevent danger would also be compromised a result of the magnitude of the reductions in Network Operating Costs and Non-Load Related capex.

2.3 If not corrected, consumer detriment and higher risk to our connected customers are an inevitable consequence. As part of this, it will be necessary to review our staff and other operational costs in light of the 23% reduction in allowed costs and, as a result, timescales for the connection of renewable generation will be extended and more frequent, longer lasting supply interruptions can be expected.

Process, Governance & Assurance

Ofgem's development of its cost assessment techniques

2.4 Ofgem consulted on their approach to RIIO2 cost assessment in June 2019 (the "June Consultation") (https://www.ofgem.gov.uk/publications-and-updates/riio-2-tools-cost-assessment-consultation). However, electricity transmission cost assessment techniques were only discussed at a very high level in the June Consultation and were presented as *potential* options. We note that the status of the June Consultation is still pending a decision, therefore Ofgem is employing cost assessment techniques without making a formal decision on their use.

2.5 Companies had no opportunity to review or assist Ofgem in the design or operation of Ofgem's cost assessment techniques or models and had no visibility of them until they were provided after the publication of the Draft Determination. Ofgem did not engage or seek input from the companies at any time. This has led to errors and inconsistencies in the cost assessment techniques which could have been avoided.

Ofgem's supplementary question process

2.6 We also note that there was no engagement by Ofgem with the network companies in some areas during the Supplementary Question ("SQ") process. For example, Network Operating Costs have been reduced by around 22% but no SQs were issued by Ofgem. Given the nature of the SQs that *were* issued during the process, we would have expected Ofgem to issue SQs to seek information from SPT to verify that such significant adjustments were accurate. This is also true of operational expenditure (Business Support and Closely Associated Indirects), where the reduction was 23%.

Cost assessment models

2.7 Ofgem's numerical models[21] used for assessment of the costs in each category have been applied, in the main, mechanistically but the results are, in some cases, inconsistent with decisions elsewhere in the Draft Determination (such as the Net Zero Fund and commitments on IIG leakage and alternatives). In other cases, individual projects have received full engineering approval, but the costs have been so severely reduced (by up to 68%) that this should have been subject to review and challenge within Ofgem.

Material errors

2.8 We note that the reductions calculated by Ofgem's cost assessment models are different to those stated in the Draft Determination (SPT Annex). For example, the Non-Load reductions are stated (SP Transmission Annex 3.63) as £132m but the Ofgem cost models indicate reductions of £141m. Similarly for Load, the reductions are stated as £114m (SP Transmission Annex 3.39) but Ofgem have advised that this figure is actually £134m. These differences have been confirmed by Ofgem via email on 20th August 2020.

2.9 We have also identified clear, significant and material errors in Ofgem's assessment and inconsistencies and contradictions amounting to over £100m. We note from our engagement with Ofgem since the Draft Determination was published many of these errors have been acknowledged by Ofgem (via a formal issues log) as requiring review and progress has been made on resolution of others but Ofgem have not confirmed that they will be corrected for the Final Determination.

2.10 The scale and scope of these errors raises questions regarding Ofgem's assurance and governance process in place prior to publication of the Draft Determination. The companies have the right to expect that information published by the regulator which has a material impact on their business operations would be subject to accuracy and consistency checks. Such checks have not been effective with respect to the errors identified.

Errors, Omissions and Inconsistencies

2.11 Through a detailed issues log, we have shared 61 items of concern with a materiality of approximately £167m. A copy of the issues log as at 4th September 2020 is included as Annex 2.

2.12 These errors are primarily attributable to: (i) incorrect translation of Regulatory Instructions and Guidance ("RIGs") and the Transmission Glossary published by Ofgem on 20 September 2019 (the "Glossary") into cost assessment models; and (ii) simple version control issues. For example, the RIGs define that costs of strategic spare assets should be recorded within the year of purchase in table C2.11 of the Business Plan Data Template ("BPDT") but that volumes should be recorded when the assets are moved from spares to be commissioned and states that "no volumes to be recorded in the Costs and Volumes Reporting Pack at the point of acquisition". Therefore, there were no volumes recorded by SPT in the table C2.5 and Ofgem's cost assessment model incorrectly removed the costs because volumes were not recorded.

2.13 A second example is where the Glossary defines thirteen cost items for 'Switchgear – Other' assets but only two of these thirteen items are to have corresponding volumes recorded. In schemes where costs are attributable to some or all of the 11 'non-volume' items but not to the 'volume' items, the costs in this category (amounting to over £5m (of which £4.6m was identified by Ofgem) in total across the 6 relevant schemes) have been incorrectly removed. In addition, by applying a wrong version of the Business Plan Data Template (BPDT) which did not account for SPT's responses to SQs ("RIIO_T2_BPDT_SPT_Dec_v9.0") to its Project Assessment Model, Ofgem has incorrectly removed £13m of civil costs from the Load-Related programme.

[21] SPT_Load_PAM_DD.xlsm, SPT_NonLoad_PAM_DD.xlsm, RIIO-ET2_SPT_NOCs_Model_DD.xlsb

2.14 We note that Ofgem has acknowledged these issues in the formal issues log and propose to correct them but the restoration of the costs in the Final Determination remains unconfirmed.

2.15 In accordance with the RIGs, the BPDT submitted with the Business Plan was accompanied by a detailed commentary file ("BPDTC") within which SPT highlighted issues we had identified where inconsistencies, omissions or ambiguities in the RIGs and the Glossary could lead to erroneous assessment. In many cases (in particular in Network Operating Costs and Non-Load Related Expenditure), the material errors detected in the Draft Determination could have been avoided had Ofgem given due consideration to the BPDTC and engaged on the highlighted issues during the SQ process.

2.16 The apparent absence of subsequent checks by Ofgem following the application of its Project Assessment Model has led to unjustified and material removals of costs which are inconsistent with decisions taken elsewhere in the Draft Determination. For example, (i) the Net Zero Fund was approved as a PCD but its costs removed from the baseline Totex; (ii) agreement of the Environmental Action Plan's costs for management of IIGs is inconsistent with the cost reductions applied during Ofgem's benchmarking and engineering assessment and (iii) the top-down benchmarking applied to BS and CAI has removed EAP opex costs that have been approved.

Methodology Issues

2.17 We have identified material errors in the design and methodologies of the cost assessment techniques applied by Ofgem to Risk and Contingency Costs, Unit Cost Analysis, Network Operating Costs and Indirect operational expenditure forming part of the Draft Determination. We have supplied Ofgem with consultants' reports from Arcadis (Risk & Contingency) and NERA (Network Operating Costs and Indirect operational expenditure) in Annex 3 in support of these and provide the following material examples.

Risk and contingency

2.18 Ofgem's assessment of Risk and Contingency as set out in the Draft Determination (SPT Annex paragraph 3.38) is based on three principles that are materially wrong.

2.19 **The first principle** is the assumption that if the expenditure profile includes costs beyond the RIIO-T2 period there is no risk exposure in RIIO-T2 (which is inferred from the formula in Ofgem's risk and contingency model which assigns a value of 0 to allowed risk and contingency where there are costs in regulatory years after 2026). This assumption is baseless. There are many approaches to risk and contingency in the delivery of infrastructure projects and for the purposes of the RIIO-T2 Business Plan, our consultant (Arcadis) recommends[22] that the expenditure profile is used as a proxy for the profile of risk exposure because it is more reflective of the risk exposure during major transmission projects. Ofgem has used the expenditure profile approach in their Project Assessment Model to adjust for costs occurring outside the RIIO-T2 period and there is no basis for deviating from this approach for the assessment of Risk and Contingency in the Draft Determination.

2.20 **The second principle** is that Ofgem's assessment methodology assumes that the risk value can be proportionately attributed to asset and non-asset costs and that asset costs already include Risk and Contingency. Ofgem has disallowed all such elements in full (SPT Annex paragraph 3.38).

2.21 During the SQ process, it was demonstrated that these assumptions are incorrect (SQs SPTL_SQ_CA42 and 51 to 55). We commissioned Arcadis, an international consultancy with significant experience in GB transmission projects, to review the detail of project costs and we present their report in Annex 3 of this response which verifies that the project costs attributable to assets which were submitted in SPT's Business Plan are tender or contract award process and do not include risk & contingency. We note that SPT's detailed cost manual was supplied to Ofgem as part of our response to SPTL_SQ_CA_25. The

[22] RIIO-ET2: Investment Plan Engineering Risk Review, Annex 3

cost manual details the sources of costs which demonstrates that risk is not embedded in the asset costs but Ofgem does not seem to have considered this in its assessment.

2.22 Ofgem's methodology of attributing risk & contingency costs to assets and non-asset costs proportionately incorrectly represents the historical risk and contingency costs incurred by SPT which are the basis for the forecast in the business plan. Historically, only 7% of incurred risk & contingency costs are attributable to assets, therefore the disallowance of this element of risk and contingency costs is incorrect.

2.23 **The third principle** is that Ofgem's assessment methodology reduces risk and contingency costs that are above the average (for the load and non-load categories) to the average. Ofgem has not provided any justification for this downward bias on costs and there is no corresponding adjustment of costs which are below the average.

2.24 We note that Ofgem has issued an SQ on risk and contingency with a view to revising some elements of their methodology. SPT will respond by the deadline date of 11/09/2020.

Unit cost analysis

2.25 Ofgem's Unit Cost assessment is not in line with best practice for this activity. The manner in which Ofgem has sought to set benchmark unit costs is incomplete, contradictory and ambiguous in many areas, which invalidates the attempt to standardise asset unit costs. The lack of transparency in the application by Ofgem of RIIO-T1 and ED sector benchmarks impedes the companies' ability to properly scrutinise the benchmarking process. As Ofgem acknowledge (ET Sector Annex, paragraph 3.11) this exercise is difficult due to data disparity and data sparseness. Ofgem state in paragraph 3.24 of the ET Sector Annex that their assessment considered "*the variation in scope of work or variation in type of plant*". We set out in Annex 3 of this response that this process has either not been applied or has been applied in a deficient way. We also note that there was no attempt by Ofgem to test the outcomes of the exercise to determine if the resulting costs were reasonable and no attempt to engage with us to understand the justifications behind what can only be described as unreasonably high adjustments to some unit costs.

Network Operating Costs

2.26 Ofgem's approach to Network Operating Costs ("NOC") has been to anchor all costs to RIIO-T1 levels (and only the first 6 years of the RIIO-T1 period). Ofgem has failed to consider the evidence presented to them in the BPDTC (their prescribed format (RIGs paragraph 2.25)) for variations from historical rates and their Network Operating Cost assessment models provide no means for such adjustments in any case. A report produced by NERA for SPT ("Response to Ofgem's RIIO-ET2 and GT2 Draft Determination on Opex Cost Assessment", Annex 3) concludes that the mechanism is entirely mechanistic and fails to analyse the reasons for changes in unit costs over time.

2.27 The use of historical costs introduces significant uncertainty which is neglected in the assessment models. This uncertainty arises because the cost and volume categorisation stipulated for these costs is completely different from the requirements set at the time they were planned and incurred and so, as a practical matter, the required data has not been recorded in most cases and we provide details in the response to SPTQ14 below. This inevitably requires estimations, apportionment and judgement to be applied, introducing a potentially significant margin of error. NERA states that this may reduce the accuracy of T1 data and undermine the comparability of T1 unit cost with T2 costs. There has also been no attempt by Ofgem to either set a 'dead band' around these costs to manage the error or to introduce a post-processing review to determine the appropriateness of the historical costs.

Indirect operational expenditure ("Indirect Opex")

2.28 Ofgem has set allowances for indirect costs (both Business Support Costs [BSCs] and Closely Associated Indirects [CAI]) using regressions, and estimates using historical data from the first six years of RIIO-T1, as with Network Operating Costs, and using only four cross-sectional observations: the three TOs along with the Gas transmission operator.

2.29 **Our review has concluded that Ofgem's Assessment of the TOs' Indirect Costs is extremely unreliable and its proposal to disallow large portions of TOs' CAI and BSC is flawed.**

2.30 A more reliable approach to setting opex allowances would be to set allowances based on current levels of indirect costs for each company, with indexation over time for inflation, RPEs, ongoing productivity and (if appropriate) changes in capex due to changing workload requirements.

2.31 At past price reviews, due to the limited comparators, Ofgem did not conduct comparative benchmarking modelling to assess TOs' efficiency and set allowances for CAI and made only limited use of it for BSC. Ofgem's own reasoning for such an approach was to avoid the risk of setting allowances using models which would be extremely sensitive to changes in model specification, data error, inherent differences between companies etc.

2.32 It is of significant concern that Ofgem is relying almost solely on a comparative benchmarking approach despite previously ruling out this form of econometric modelling, due to its limitations, particularly from only four cross-sectoral observations. Ofgem indicated in its June Consultation that their intent was to "limit the use of drivers that are specific to network sectors, such as network length and MEAV". However, the most material cost driver used in the modelling of Indirect costs is modern equivalent asset value ("MEAV"). Ofgem has considered only a very narrow range of cost drivers. Another flaw in Ofgem's models is the "endogenous" nature of cost drivers it has used to explain variation in costs. For instance, Ofgem has used (amongst other drivers) totex and the number of FTE employees to explain indirect costs. These are endogenous, as they are controllable by the company and may both influence and be influenced by the dependent variable in Ofgem's regressions.

2.33 The inputs to MEAV like unit costs are very subjective and a wide range of values can be calculated from simple changes in inputs. No guidance was provided to promote consistency of MEAV assumptions. Considering the importance now placed on this driver, the lack of consistency and absence of any clear instructions for its calculation, significantly undermines the accuracy, and fairness of the output of the modelling exercise. Ofgem needs to perform a consistency review and impact assessment, for example utilising consistent unit costs across the TOs, to assess the potential error from inconsistent MEAV methodologies across the limited data points.

2.34 Ofgem's decision to rely on comparative cost benchmarking for Indirect Opex is also inconsistent with its approach for NOCs which relies upon an assessment of individual TOs' historical and forecast costs. This view is also shared by Ofgem's economic consultants ECA, who referenced[23] that further scrutiny of the modelling results is required before being used to set allowances for the RIIO-T2 period, particularly for SPT.

2.35 National Grid and SP Energy Networks (SPEN) appointed NERA to review the approach proposed by Ofgem for setting allowed levels of operating costs for the four Transmission Owners (TOs) – National Grid Electricity Transmission, National Grid Gas Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission – in the RIIO-T2 Draft Determination. NERA concludes in its report[24] that Ofgem's statistical models are not sufficiently reliable to support its conclusions on the efficient levels of opex the TOs need to incur over the T2 control period, and to quantify how these allowances will need to adjust depending on the eventual scale of their capex programmes. NERA has determined Alternative Regression Models that Pass Ofgem's Model Selection Criteria Show a Wide Range of Efficient Costs for the TOs. NERA have also found due to the small sample size and the wide variation in the TOs' scale, there is a wide range of uncertainty around the degree to which the TOs' "efficient costs" vary from their business plan forecasts. In

[23] ECA (7 May 2020), RIIO-GD2 and T2: BSC and CAI assessment methodology, Methodology Paper, p. xii.
[24] NERA report: Response to Ofgem's RIIO-ET2 and GT2 Draft Determination on Opex Cost Assessment

their report NERA identify a number of other regression model specifications which could also provide a basis for explaining variation in the TOs' costs and predicting their costs over the T2 period

2.36 Outwith Ofgem's modelling approach, there are a number of areas where Ofgem has failed to take account of additional factors that impact on the level of perceived inefficiency. Therefore, we have proposed further adjustments that outline areas of expenditure that we believe require separate assessment as the modelling approach adopted by Ofgem cannot be expected to legislate for these. These can be found in our response to SPTQ15 below.

Project Justification

2.37 We welcome Ofgem's findings that the needs cases presented by SPT in its Business Plan are robust and well evidenced. We have some concerns however that Ofgem's assessment process did not consider all the evidence presented and instead placed a binary reliance on the availability of an Engineering Justification Paper (EJP).

2.38 Of the projects that were not approved by Ofgem and classified as 'non-load', four projects relate to land and planning activities, two projects relate to community initiatives and one project relates to the Environmental Action Plan. These projects should have been classified as 'Other' by Ofgem. These activities therefore fall outside the scope of Ofgem's Engineering Justification Paper Guidance published on 19 September 2019 and so the necessary evidence required to justify these projects was presented in the core Business Plan document. We have, in any case, provided additional evidence which has also been included in Annex 3 of this response.

2.39 We are also concerned by Ofgem's assessment of SPT's critical Torness shunt reactor project (scheme SPNLT2047). Specifically, the engineering assessment by Ofgem's consultants has recommended a course of action that would not only fail to address the end of life condition (Atkins RIIO-T2 TO Submission Review Summary Report SPT Appendix A: stating refurbishment is feasible) but would destroy the evidence of its existence by their recommendation of reconditioning the oil[25]. It is of significant concern that such a damaging course of action would be recommended. Further, Ofgem has also disregarded the objective measurement (EoL modifier) of their condition given by the approved NARM methodology (which it has accepted in every other scheme proposed by SPT) and the outcome of the CBA provided with the Business Plan and summarised in the EJP. Ofgem's engineering assessment has recommended a course of action that would, according to accepted international best practice, result in an intolerable risk of failure and would be demonstrably less beneficial for consumers. We have commissioned a further independent report in support of this investment which supports SPT's justification of the project. We note that as a result of Ofgem's decision, we have been forced to postpone contract awards for this project, thereby putting its planned delivery date at risk.

[25] The presence of end of life winding insulation is indicated by the Degree of Polymerisation which is calculated by analysing the concentration of 2-FAL compounds which have accumulated in the insulating oil. Reconditioning the oil would remove the 2-FAL compounds, hence destroying the evidence of deterioration and making trend analysis impossible.

Responses to Consultation Questions - Expenditure and Outputs

Electricity Transmission Annex

ETQ9. Do you have any views on our overall approach to setting totex allowances?

2.40 Our detailed responses to the approach used to set the Totex allowances can be found in the responses to the individual Totex components as listed in the SPT Annex (SPT Q11-16) are detailed below.

SPT Annex

SPTQ6. Do you agree with our proposals on the PCDs? If not, please outline why.

2.41 We agree with the proposal by Ofgem to accept the majority of PCDs proposed in SPT's Business Plan. However, we do not agree with the proposal to reject three proposed PCDs.

Demand Connections – Network Rail (Rejected)

2.42 We do not agree with the rejection of the PCD associated with the provision of reinforcement and new connections to Network Rail. The proposed schemes are at present contracted to connect, with the result that we are legally obliged to provide the connections to Network Rail and are in various stages of delivery. Noting that these schemes have been rejected due to a lack of justification, we have submitted new Engineering Justification Papers ("EJP"), included in Annex 3 of this response.

2.43 We also believe this PCD should be approved when taken in view of a wider whole energy system and Net Zero context. The works proposed all align with the recently published Rail Services Decarbonisation Action Plan (28th July 2020) published by Transport Scotland with the plan to decarbonise Scotland's rail passenger services by 2035.

Wider Works - Circuit rating management system (rejected)

2.44 We believe that our proposed Circuit Rating Management System will bring significant network and consumer benefits by maximising the utilisation of our existing assets and reducing network constraints. Therefore, we do not agree with the rejection of this PCD. We have carried out additional analysis to strengthen the justification for this project and have submitted an updated EJP, included in Annex 3 of this response (also see our response to SPTQ11 detailed below).

Energy Not Supplied (ENS) ring fenced UIOLI funding

2.45 This proposal targets improved reliability for the approximately 2,000,000 distribution connected demand customers who can be impacted by faults on the transmission network. We do not agree this should be rejected and have laid out our response in ETQ*8* as part of our response to the Energy Not Supplied ODI.

Interactions with other mechanisms

2.46 There are proposed PCDs where there are interactions with other mechanisms and Ofgem have not proposed how these interactions will operate. Specifically, we reference Demand Connections – Network Rail, Demand Connections – SP Distribution, Generation Connections – Shared Use and Generation Connections Sole Use (SPT Annex Table 11) which are all subject to an uncertainty mechanism. Additionally, NARM is referenced as a PCD in Table 1 of the ET annex but this would be interactive with the specific NARM mechanism. Further information from Ofgem is required on this point to allow proper scrutiny of the proposed PCDs.

SPTQ7. Do you agree that SPT's bespoke Net Zero Fund should be included in RIIO-ET2?

2.47 As detailed within our Environmental Action Plan (Annex 7 of our Business Plan) on pages 109-112, our Net Zero Fund (NZF) has been supported by a wide range of stakeholders and will deliver wider societal benefits of £3 for every £1 invested. Our £20m fund proposal does not include any associated SPT related works, such as engagement activities with stakeholders to determine key projects, or the funding of associated resources. Therefore, we had proposed a CVP for our fund. In our Business Plan we stated that consumers will realise £60m of benefits. We must clarify within this response that the £60m was not our proposed reward for this CVP. We strongly support our consumer benefits value of £60m, but in relation to any reward SPT would receive for delivering this consumer benefit, we consider it appropriate to recognise the additional costs to SPT of delivering this fund as a minimum. We propose that this value is 10% of the £60m benefits value with the TIM applied in order to ensure SPT is able to recover its costs associated with managing this fund.

SPTQ8. Do you have any views on the conditions we are proposing applying to SPT's bespoke output?

2.48 We support Ofgem's proposal that the NZF would be funded on a use-it-or-lose-it basis, therefore, any unspent allowances would be automatically returned to customers. We also support the publication of a report which details the completion of each project about progress against its key milestones, budget, deliverables and outcomes. However, we would highlight concerns with the associated licence drafting in relation to this condition. It must be recognised that SPT is not within the control of the outputs associated with each project as we will not be delivering the projects ourselves. There is also a risk that if this obligation is placed on SPT, it will not support projects where there is an element of risk. Therefore, some of the most innovative and potentially most valuable longer term projects may not be taken forward.

SPTQ11. Do you agree with our proposed allowances in relation to load related capex? If not, please outline why.

2.49 We have a number of concerns about Ofgem's assessment of need cases and allowances, as outlined in the following paragraphs.

<u>Disallowed schemes</u>

2.50 A number of load-related schemes have been rejected by Ofgem, as summarised in the table below. Where schemes have been rejected due to insufficient justification, we have provided new or updated EJPs as indicated in the table below. For a number of schemes, the Ofgem position is not clear, or a reason for rejection of the scheme has not been provided by Ofgem. In such cases, we are asking Ofgem to clarify its position, as also outlined in the table.

2.51 We do not agree with the rejection of schemes associated with the provision of reinforcement and new connections to Network Rail. The proposed schemes are at present contracted to connect and are in various stages of delivery. As explained in our response to SPTQ6 above, Ofgem has required additional engineering justification and therefore we have submitted alongside this consultation response updated EJPs associated with the three Network Rail schemes.

2.52 We are disappointed by the rejection of our proposal for a Circuit Rating Management System and do not agree with Ofgem's rejection of this scheme. In our view, this scheme will provide significant network and consumer benefit and we note that the Atkins review indicates that it is good value for money (see p. 74 in Appendix E of the Atkins TO Submission Review Summary Report). The proposed system would allow us to continuously fine-tune the declared ratings of our transmission circuits, so that these can be maximised during normal network operation, and under outage conditions, to reduce network constraints. However, we have carried out additional analysis to demonstrate that the scheme provides significant network constraint cost savings and have submitted an updated EJP.

2.53 Branxton 400kV is a major new substation development for the connection of a significant amount of offshore wind generation and the Eastern HVDC Link between Torness and Hawthorn Pit. This project has been rejected as the Ofgem view is that there is uncertainty around the timing and needs case and that Uncertainty Mechanisms ("UMs") are available to progress this project. Branxton does not qualify for Large

Offshore Transmission Investment ("LOTI") as it is not a NOA project and the total cost (£93.3m) falls below the LOTI threshold of £100m. Although the project qualifies for Medium Sized Investment Re-opener ("MSIP"), we would have to wait for the reopener window in January 2024 to make a submission. We are currently contracted to connect 1400MW of offshore generation at Branxton in 2026 and the connection of the Eastern HVDC Link is planned for 2027. Submitting a MSIP reopener in January 2024 to obtain Ofgem approval would therefore be too late to meet the project timescales. While we agree with Ofgem that Branxton would be better suited to the MSIP reopener, rather than in the SPT baseline, an additional, earlier reopener window is required. If that approach is not acceptable to Ofgem, a bespoke UM for Branxton is required that would allow a reopener to be submitted at a time that will not lead to a delay in delivering this project.

Table 2: Disallowed Schemes

Scheme	Ofgem Draft Determination – SPT Annex	SPT Response
SPT20066/7/8 Charlotte Street 275/33/33kV New SGT1	Paragraph 3.21, table 18 and footnote 35 on p.43 imply that this scheme has been approved and it is not explicitly rejected in the text. However, this project is marked as rejected in the Ofgem Project Assessment Model tables without further justification.	During discussions (21 August 2020), Ofgem confirmed that the project has been rejected as they are not in receipt of an EJP. Ofgem did not raise any SQs about the justification but a new EJP (EJP_SPT_SPT20066) has now been submitted and is included in Annex 3 of this response.
SPT20096/7/8 Network Rail Marshall Meadows	Rejected: not justified.	Ofgem did not raise any SQs about the justification but a new EJP (EJP_SPT_SPT20096) has now been submitted and is included in Annex 3 of this response.
SPT20099/100 Network Rail Innerwick	Rejected: not justified.	Ofgem did not raise any SQs about the justification but a new EJP (EJP_SPT_SPT20099) has now been submitted and is included in Annex 3 of this response.
SPT200195/6 Network Rail Currie	Rejected: not justified.	Ofgem did not raise any SQs about the justification but a new EJP (EJP_SPT_SPT200195) has now been submitted and is included in Annex 3 of this response.
SPT200114-7 E2DC Eastern Subsea HVDC Link	Not approved in the Ofgem Project Assessment Model tables. No further justification provided.	During discussions (21 August 2020), Ofgem confirmed that the project has been rejected as they are not in receipt of an EJP. Ofgem did not raise any SQs about the justification, but clarification and an updated EJP (EJP_SPT_SPT200136) have now been submitted and is included in Annex 3 of this response.
SPT200168/9 Branxton 400kV Substation	Rejected: timing and needs case uncertainty. A UM will be available to SPT to fund this project.	As commented on above, the project (£93.3m total) is below the £100m LOTI threshold and is not a NOA project. For an MSIP submission, we would have to wait for the MSIP reopener window in January 2024. This would be too late to connect 1400MW of offshore wind generation in 2026 and the Eastern Link in 2027. An additional, earlier MSIP reopener window is therefore required. If that approach is not acceptable to Ofgem, a bespoke UM for Branxton is required.
SPT200130/1 Circuit Rating Management System	Rejected: limited justification in terms of quantifiable output. The Atkins review indicates that the project provides value for money.	Ofgem did not raise any SQs about the justification, but an updated EJP (EJP_SPT_SPT200130) has now been submitted and includes cost benefit analysis showing the network and consumer benefit of this scheme. This EJP is also included in

		Annex 3 of this response
SPT200194 Western HVDC Link (Onshore) (Construction)	Not approved in Ofgem Project Assessment Model tables.	Clarification is required on the decision taken. This is a crossover scheme, but it has not been treated like the other crossover schemes included in Table 26 of the SPT Annex.

Project assessment model errors

2.54 After reviewing Ofgem's Project Assessment Model, discrepancies were found between (i) the volumes and unit costs submitted by SPT in the last issued version of the Business Plan Data Tables and (ii) the volumes and costs used by Ofgem as inputs to its Project Assessment Model. This is due to Ofgem applying a wrong version of the BPDT which did not account for SPT's responses to SQs ("RIIO_T2_BPDT_SPT_Dec_v9.0"). This has a clear impact on the allowance, given that there are volumes missing in the PAM from several schemes mainly associated with Civils.

2.55 Section 3.48 of the SPT Annex states that Ofgem *"propose to give an allowance that matches what has been proposed by SPT"* for civil works and other non-unit cost categories, and that these costs have been classified as high confidence. This means that all "Civils (Direct)" costs together with "Other (Direct)" costs should have been passed through to confirm the given allowances. We have undertaken a review on a scheme by scheme basis and have found the following issues related to these costs:

- *Civils costs:* Out of the 58 approved schemes, 19 have a material cost reduction related mainly to "Civils associated with Site Access", "Civils associated with Platform Creation" and "Civils-other". Our view is that all these costs have been incorrectly rejected and affect the proposed allowances. Overall, this leads to an erroneous reduction of £12.55m on the baseline allowance.

- *Other (Direct) costs:* Out of the 58 approved schemes, 27 of have had "Other (Direct)" costs completely removed, leading to an erroneous reduction of £14.93m on the baseline allowance.

2.56 We note that Ofgem have acknowledged these errors but have not confirmed that they will be corrected for the Final Determination. Our view is that the treatment of these costs should be reviewed and corrected by Ofgem. It is also important to highlight that these reductions have a significant impact on the calculation of both the sharing factor for the Totex Incentive Mechanism ("TIM") and the Business Plan Incentive ("BPI").

Unit Costs

2.57 Please refer to our SPTQ12 response below.

Risk and Contingency Errors

2.58 Please refer to our overarching comments to this Chapter above and to our SPTQ12 response below.

BPI Stages 3 and 4

2.59 We agree that the East Coast 400kV Incremental Reinforcement ("ECUP") and Denny to Wishaw 400kV Reinforcement ("DWNO") should not be subject to the BPI and TIM mechanisms as outlined in paragraph 3.51 of the SPT Annex. However, we note that while DWNO (SPT200106/7) has been marked as BPI exempt in the Ofgem Project Assessment Model, this is not the case for ECUP (SPT200110/1). This should be corrected in the Ofgem Project Assessment Model and would lead to a BPI penalty reduction.

2.60 Our funding for pre-construction activities (as outlined in EJP_SPT_SPT200136) has been reduced significantly, despite costs being in line with pre-construction expenditure in RIIO-T1 and the 2.5% of anticipated project cost considered efficient by Ofgem (paragraph 4.42 in the ET Sector document). We also note Ofgem's PCF proposal in the ET Sector document and that pre-construction funding may be sought via an alternative mechanism such as MSIP as outlined in paragraph 4.55 of the ET Sector document (also see our response to ETQ11). In our view, the reduction in pre-construction funding has an erroneous impact on the BPI (£1.39m penalty), given that the cost has effectively been moved from the baseline to a UM, where costs can be assessed when projects and the scope of pre-construction activities are less uncertain. Therefore, pre-construction funding associated with NOA projects, or e.g. synchronous compensation projects (via our Net-Zero Operability UM proposal) that can be progressed via a UM, should be BPI exempt.

SPTQ12. Do you agree with our proposed allowances in relation to non-load related capex? If not, please outline why.

2.61 We refer to our overarching comments to this Chapter above. We have significant concerns in a number of areas of Ofgem's assessment of need cases and allowed cost. We highlight the lack of engagement by Ofgem in this area prior to the publication of the Draft Determination. It is notable that the cost assessment techniques to be applied were not subject to a consultation and there was no working level engagement at any stage of the process. Most of the issues identified below could have been resolved through engagement.

Errors

2.62 We have identified a number of errors with a material impact on the allowed non-load related capex. These have been raised with Ofgem via the issues log included in Annex 2. Ofgem have acknowledged these issues in the issues log and some progress towards their resolution has been made. However, it is not yet confirmed that the costs, which total £70m (according to the PAM) will be restored at Final Determination:

- The Net Zero Fund is accepted by Ofgem and has been allocated as a PCD but its costs were removed by Ofgem's Project Assessment Model (£20m). This is a manifestly contradictory outcome.
- The refurbishment of Grangemouth SGT1 was approved by Ofgem in the engineering review but its costs were removed by Ofgem's Project Assessment Model (£0.57m). This too is a manifestly contradictory outcome.
- Costs for strategic spares were approved by Ofgem in the engineering review but Ofgem's Project Assessment Model does not correctly apply Ofgem's own guidance on population of volume data tables (RIGs). The Ofgem Project Assessment Model thus removed the associated costs (£2.5m). This too is a manifestly contradictory outcome.
- The Ofgem asset categories (defined in the Glossary) and BPDT design did not include definitions for the assets to be delivered in respect of 13 projects (schemes SPNLT2049 to 54 and 56 to 62 inclusive). As a direct result of this, it was not possible for SPT to assign volumes in the appropriate BPDT. This anomaly was clearly explained to Ofgem in our BPDTC but the costs of those relevant projects were nonetheless removed in Ofgem's Draft Determination Project Assessment Model (£32m[26]). We note that there was no engagement by Ofgem with us on this point between Business Plan submission and Draft Determination.
- Ofgem raised a query in SQ SQ_SPTL_CA_64 where the asset category Switchgear - Other contained costs in BPDT table C2.5a but no addition volumes in C2.5. Our response to this SQ explained that this will in accordance with the Glossary. Ofgem accepted this and prior to the publication of the Draft Determination adjusted their Project Assessment Model to restore the costs. Further, our response to SQ SQ_SPTL_CA_64 highlighted other schemes where the same adjustment should have been applied but Ofgem did not do so which has resulted in the unjustified removal of a further £4.6 million in costs in relation to those schemes.

[26] Note that scheme SPNLT2055 would be similarly impacted by this issue but has been rejected by Ofgem. Additional information has been provided for this scheme (see item 2 in 'Need Cases') but a further £17.9m would be removed unless this issue is resolved.

- Ofgem's Project Assessment Model failed to operate correctly on Civil asset categories in two schemes (SPNLT2037 and SPNLT20100), incorrectly removing costs (£9.22m).

- Ofgem's Project Assessment Model did not contain volumes for scheme SPNLT2040 (which were present in the SPT BPDT submission), incorrectly removing costs (£1m).

- Ofgem's Project Assessment Model did not use the correct version of the BPDT supplied by SPT, i.e. the version supplied in response to SQ SPTL_SQ_CA_45 ("RIIO_T2_BPDT_SPT_Dec_v9.0"). Instead, Ofgem appear to have used an outdated version of the SPT Business Plan Data Template (SPT do not know which version was used). This version control issue disallowed small values in some schemes and over-awarded similarly small sums in others resulting in a net increase in costs (£0.14m)

Additionally, as noted above Ofgem indicated that following our response to SQ SQ_SPTL_CA_64, they manually intervened to correct the Project Assessment Model, restoring £6.3m to one scheme. However, the BPI calculation did not account for this adjustment resulting in costs being incorrectly penalised (£0.63m).

<u>Need cases</u>

i. The decision to reject the Torness shunt reactor replacement (scheme SPNLT2047) is based on a flawed assessment by Atkins (Atkins RIIO-T2 TO Submission Review Summary Report SPT Appendix A). SPT undertook independent assessment of the reactors' condition (supplied to Ofgem in SPT's response to SPTL_SQ_ENG_7) and an independent audit of the decision-making methodology (which was provided in Annex 23 of the Business Plan) which supported SPT's decision. Atkins proposed approach would not manage the end of life condition issue and would have removed all possibility of ongoing surveillance of the impending failure. Ofgem have disregarded the approved NARM metric which provides an objective measure of the assets' condition. Ofgem have also disregarded the outcome of the Cost Benefit Analysis and have effectively forced SPT into a position which is demonstrably detrimental to consumers' interests. We have provided Ofgem with a detailed review of their decision in an update of the EJP (included in Annex 3 of this response) which has been supported by an independent expert's report. We have consulted with EdF, the key stakeholder in this case, who agree with our proposal to replace the reactors and have expressed concern around the material, condition, fire and environmental risks resulting from the Draft Determination decision. This is in addition to the significant system operability challenges which would result.

ii. The decision to reject the 400/275kV telecomms resilience programme appears to be because the fundamental driver behind this programme - that the existing basic architecture design will not be resilient for the needs of the network in RIIO-T2 and beyond - is not accepted by Ofgem but has received strong stakeholder support (please see Chapter 10 – Stakeholder Engagement). We have provided additional information as noted by Ofgem in an updated EJP (included in Annex 3 of this response) and which has been supported by an independent expert's (WSP) review, as referenced in the EJP.

iii. The decision to remove the funding associated with the SF_6 management project SPNLT20140 leaves SPT without the funding mechanism to discharge its obligations under the F-Gas regulations which are legally binding on SPT. The contention in the Draft Determination is that further evidence was required to support SPT's conclusion that repairs or refurbishments are not feasible in these cases. Therefore, Ofgem's conclusion should have been to allow the refurbishment costs and provide a means of funding replacement, should that prove necessary. SPT does not agree with Ofgem's contention and have provided further evidence in support of this position in an updated EJP (included in Annex 3 of this response).

iv. We have provided additional EJPs (included in Annex 3 of this response) to support the inclusion of projects which commenced in RIIO-T1 but will deliver outputs in RIIO-T2. For projects commencing in RIIO-T2 but delivering outputs in RIIO-T3, according to the Draft Determination (paragraph 3.33 of the ET annex) the submitted costs should have been collected into a bridging fund but instead they have simply been disallowed. We have, again, provided additional EJPs (included in Annex 3 of this response) for these projects.

Unit costs

2.63 We also comment on this in our overarching comments to this Chapter above.

2.64 The unit cost benchmarking approach used by Ofgem has resulted in erroneous reductions in project costs. We note that Ofgem decided not to consult on the cost assessment methodology used and therefore we have had no opportunity to help make the process effective. The two main issues are (i) the definition of each unit cost and (ii) Ofgem's benchmarking methodology.

Unit cost definition

2.65 Each unit cost is defined in Ofgem's Transmission Glossary V1.3 published by Ofgem on 20 September 2020 (the "Glossary"). SPT provided extensive feedback on this Glossary through issues logs shared with Ofgem during 2019, its application to the completion of the Business Plan Data Templates ("BPDT") and provided the issues log with the Business Plan submission.

2.66 There are five principal failings in the Glossary that prevent the methodology used by Ofgem being applied fairly, and lead to outcomes that are clearly wrong.

i. The definitions of assets are incomplete. We have noted in the development of the Glossary and in our Business Plan submission that some cost items are not defined. The allocation of these cost items is likely to have been applied differently by each company. For example, Gas Insulated Busbars are not defined in the Glossary but add up to 20% to the circuit-breaker unit cost in SPT's Business Plan. These costs vary site-by-site due to the length of the Gas Insulated Busbar required and the topology of each site, so this item will add such a distortion that it should have been removed from the unit cost analysis. However, as there is no separate item to which costs can be allocated, it has invalidated the analysis of this cost category. It is likely that other companies have applied these costs to a different category, invalidating the comparison. A further example is of overhead line conductors. These can be single or in configurations of two, three or four. The lack of differentiation has, by our understanding, prevented Ofgem being able to apply unit cost benchmarks for these asset categories. As a result, all such costs are (incorrectly) being classified as lower confidence for the purposes of TIM and the BPI.

ii. The definitions are ambiguous. This ambiguity is evident in a number of asset areas and invalidates the methodology used. For example, in substations for a circuit-breaker and bay replacement project, protection costs are defined in three different asset categories: Protection, Circuit Breaker and Switchgear (Other). Similarly, for Gas Insulated Switchgear, somewhat counterintuitively, power cables are included in the definition of Circuit Breaker but also exist as an asset type in their own right. This has added 60% to the unit costs of circuit-breakers in SPT's Business Plan. From our examination of Ofgem's Unit Cost Models received by SPT on 29 July 2020, it is highly probable that each company has applied these in different ways, leading to distortion of the unit costs. Ofgem did not seek to normalise these definitions after the Business Plans were submitted.

iii. The definition of some unit costs is very wide which can assist in ensuring all cost items are included but gives rise to distortions in the creation of unit cost benchmarks (and also leads to ambiguities in definitions as noted above). For example, the definition of asset type 132kV CB (Air Insulated Busbars) (OD) contains 10 cost items. SPT has projects to replace this asset type where there is only one of the cost items involved in the activity (and even then, only a subset of that item) and also has a project where all 10 cost items are relevant. The result is unit costs for the same asset where the highest value is over 5 times the lowest value. Both of these cases are entirely valid within the Glossary definition but which add significant distortion to the unit costs.

iv. Applicability of unit cost sources. The use of RIIO-T1 benchmarks in circuit-breakers means that commitments to use alternatives have effectively been de-funded as these were not used in RIIO-T1. This is despite this initiative being accepted in SPT's Environmental Action Plan. Furthermore, Ofgem has used ED sector costs to benchmark 33kV cable costs. This is not an applicable source. ED sector 33kV cables are primarily associated with feeders, whereas TO costs relate only to transformer LVs. This leads to significant differences. It is reasonable to expect Ofgem should be aware of these differences before deciding on this application.
   - The capacity of ED sector feeder cables is typically 30MVA or less which can be achieved by a single core-per-phase. TO capacities are up to 120MVA requiring four cores per phase with a minimum of three cores per phase for the lower capacities on SPT's network. This immediately leads to multiples of the DNO costs being incurred.
   - The lengths are very short (average 75m for SPT), preventing economies of scale being achieved when compared with ED sector costs. The SPT costs will also be distorted by the high relative costs for terminations and outdoor structures on short lengths.
   - The SPT cables are all laid within live compounds. This requires hand-digging of trenches which increases the costs relative to the ED sector benchmark.

   Ofgem has not provided any details of how ED sector benchmark costs were derived which has impeded SPT's scrutiny of Ofgem's cost assessment.

v. Volume definitions distort the unit costs. For example, in the Switchgear (Other) category, there are 13 cost items of which only 2 are to be recorded as volumes. This has led to errors in the cost modelling as costs were removed where there were (correctly) no associated volumes. This has also led to this category having no Ofgem unit cost, again incorrectly causing this category to be classified as lower confidence in the calculation of TIM and BPI.

2.67 We have provided a detailed review of these issues (RIIO-T2 Draft Determination Unit Cost Review, Annex 3 of this response) and propose that we work collaboratively with Ofgem to undertake a more detailed review of the errors described in the report. SPT have transparently supplied its detailed Manual of Standard Costs to Ofgem (in response to SQ SPTL_SQ_CA_25) and a detailed review on this basis would, we believe, permit correction of the errors that have resulted from Ofgem's cost assessment process.

2.68 We have fed back to Ofgem on a number of occasions that the design of the BPDT would lead to distortions and invalidations of calculated unit costs (via the issues logs during the development of BPDTs, via the BPDTC and via responses to SQs). Ofgem's design of BPDT tables C2.5 and C2.5a cause refurbishment activities to be classified as replacement where replacement of other assets is the prime driver or highest level activity (as defined in the Glossary) of the intervention. This has distorted some unit costs to the extent that Ofgem could not generate a benchmark cost. This, in turn, has led to £128m of costs being classified as low confidence despite SPT providing full details and worked examples of its Manual of Standard costs. We note and welcome that this data has allowed Ofgem to declare some asset costs as high confidence as a result. Therefore Ofgem should have also applied this approach to the other asset categories.

2.69 We note that the cost reporting for RIIO-T2 is wholly different from RIIO-T1. The Business Plan required (as set out in the RIGs) restatement of historical (T1) costs in this new T2 format. As historical costs have not been recorded or reported in the specified format, estimates, apportionment and approximations are necessary to complete this exercise which inevitably leads to a degree of uncertainty. The absolutist approach taken by Ofgem takes no account of this which leads to material errors. Ofgem should apply a dead-band around these historical values in recognition of the inherent uncertainty. This is good practice in the industry as evidenced by the independent report by Arcadis commissioned by SPT and submitted with Annex 23 of the Business Plan.

Benchmarking methodology

2.70 Ofgem has attempted to use a top-down methodology to set benchmarks with an extremely limited data set. The wide variances in unit costs (see above on *Unit Cost Definition*) across a very small sample set generate wholly unreliable benchmarks.

2.71 In any benchmarking exercise, it is accepted that there will be 'winners' and 'losers'. If there is a sufficiently large portfolio of applicable projects and if the standard deviation of the benchmark cost is sufficiently small, there is a balancing effect which will ensure no single party is unfairly prejudiced. However, neither is true in this case. Further, the methodology operates by awarding the lower of the benchmark and submitted cost so there can never be 'winners'. As a result, allowed costs are effectively suppressed to unachievably low levels across the portfolio with no balancing effect of allowing TOs to capture the economic benefit where their efficient costs fall below the relevant benchmark.

Risk and contingency costs

2.72 In the SPT Annex paragraph 3.38, Ofgem states that SPT's asset costs already contains a component that accommodates the associated risk and contingency. In fact, we provided evidence to the contrary in our Business Plan[27] and in responses to SQ_CA_51 to 55 which appears to have been ignored by Ofgem in its assessment. Ofgem's assessment model[28] assigns risk and contingency to asset costs in proportion to the total project value. This incorrectly represents the historical risk and contingency costs incurred by SPT which are the basis for the forecast in the business plan. Historically, only 7% of incurred risk & contingency costs are attributable to assets, therefore the disallowance of this element of risk and contingency costs is incorrect. We have provided in Annex 3 an independent report into the methodology and model in support of our position that asset risk costs should be reinstated.

2.73 We note that in Ofgem's Project Assessment Model, projects whose output is delivered wholly within RIIO-T2 but which have a small residual spend in RIIO-T3 have had all risk and contingency costs disallowed. This is a material and unjustified error which should be corrected as the assumption that there is no risk exposure in RIIO-T2 for these projects is simply wrong. To that end, we have presented in Annex 3 a report from Arcadis that demonstrates:

- The asset costs in our business plan do not include embedded risk.
- The principle of the applied 'ratchet' to the mean is unfair and wrong
- The time profiling of risk assumed in the Ofgem assessment model is flawed and not in line with best practice.

SPTQ13. Do you agree with our proposed allowances in relation to non-operational capex? If not, please outline why.

2.74 We welcome Ofgem's award in full of the Property and Small Tools, Equipment, Plant & Machinery (STEPM) expenditure proposed in our Business Plan submission. As noted, SPT made no funding request under Vehicles and Transport in this category.

2.75 We further recognise the approval of four projects; accepted in the baseline. There was one project which was rejected by Ofgem at the Justification stage with no explanation provided by Ofgem or its consultants and we request clarity so that we may rectify this matter.

2.76 We disagree with Ofgem's evaluation of our Non-operational IT and Telecoms business plan, in particular regarding the perceived lack of detail around project planning, resourcing and cost assurance:

[27] Annex 23 Appendix B – Arcadis RIIO-ET2 Investment Plan Efficiency Review, section 5.1.1.
[28] SPT_Risk_Contingency.xlsx

- On project planning, SPT has detailed plans for the initial period of RIIO-T2 with more granular detail during the latter phases and a high level breakdown of this is included in the information provided in response to SPTL_SQ_CA_26. An update of those plans is also provided with this response. Further detail can be provided if required.

- On resourcing, SPEN is undertaking an IT transformation programme to increase internal resources, reduce reliance on external resources and build an in-house capability that can be used to develop, maintain and operate our IT estate. We have also established a Networks-focused Centre of Excellence to take overall responsibility for the implementation of technology across the business and this organisation has taken responsibility for the development and delivery of our Digitalisation Strategy. We have described how these resources will be utilised to deliver our programme in section 6 of the updated IT plan supplied in Annex 3 this response. Again, more details can be provided if required.

- On cost assurance, SPT has provided a detailed breakdown of how our costs were derived in section 6 of the of the updated IT plan supplied with this response. Wherever possible, this has been referenced to costs provided by external parties but where this was not possible, input was sought from a range of internal resources. Our Non-operational IT and Telecoms business plan was independently assessed by Gartner as part of an assurance activity undertaken by SPT and considered to be fully justified and generally in alignment with Gartner's expectations and their view of similar investment across the energy and other sectors.

2.77 Further clarification is requested from Ofgem on the basis on which it has determined the cost reductions for individual projects – whether they were moved into baseline or IT&T re-opener mechanism. The range of reductions (18-24%) made by Ofgem appears high when judged against historic delivery costs for projects of similar nature.

2.78 However, recognising Ofgem's position in the Draft Determination with regard to lack of certainty for IT projects planned for the end of RIIO-T2, SPT agrees with the proposed re-opener window with no materiality threshold and no aggregation.

2.79 We note that, in contrast to the Engineering Justification Paper Guidance issued by Ofgem on 19 September 2019, no guidance was issued by Ofgem regarding the form of or content required in relation to project and cost justifications. Given the relative cost materiality of the IT projects compared to load-related and non-load related projects, the extent of the justification provided in the Business Plan was proportionate. However, had guidance been published, we would have provided the requisite level of detail.

SPTQ14. Do you agree with our proposed allowances in relation to network operating costs? If not, please outline why.

2.80 We do not agree with the proposed allowance in relation to network operating costs. We also refer to our overarching comments above in this Chapter relating to network operating costs.

2.81 We welcome our allowance for Operational Protection Measures and IT Capex having been accepted in full, however, do not agree with the reduction to allowances that have been made in other areas because the evaluation methodology has been on a strict unit cost basis comparing SPT's cost in RIIO-T1 with forecast costs in RIIO-T2 assigning the lowest available cost for each activity. This methodology does not allow for any necessary, justified changes in practices by SPT, increasing associated costs. These can be attributed to new technology, additional costs due to deterioration of asset condition or process enhancements to ensure maintenance of asset health. It also appears the narrative provided for our network operating costs has not been considered when evaluating our allowances. This reduces our proposed expenditure on our network operating costs by 22%.

Evidence of costs and justification

2.82 We have gone to great lengths to ensure we have represented our network operating costs in the format required in the Business Plan Data Tables ("BPDT") by Ofgem. We have also gone to great lengths to describe, in the associated Business Plan Data Table Commentary ("BPDTC"), areas where there are increases in our costs between RIIO-T1 and RIIO-T2 and where potential issues were likely to arise with unit cost analysis. The changes to our Direct Opex costs between regulatory periods, reported in RIIO-T1 in Asset Management Table 3.3, have also been described in detail in SPT Business Plan Annex 3: Strategic Investment Plans – Non-Load and Annex 19: Investment Plan Additional Analysis.

2.83 It appears, however, that the evidence presented in the BPDTC (as required by Ofgem's Guidance on Business Plan Data Templates Version 1.4) and Annexes 3 and 19 of our Business Plan has not been considered by Ofgem during its analysis of our network operating costs. Instead Ofgem's analysis of our network operating costs is based on the following:

i. Ofgem state in paragraph 3.82 of the SPT Annex that the Draft Determination allowances have been based on the comparison of SPT's proposed rates with our historically incurred RIIO-T1 rates. However, a comparison of historic rates of expenditure to forecast rates of expenditure does not take into account:
    a. necessary, efficient additional costs associated with new technology employed in RIIO-T1;
    b. additional costs due to deteriorating asset condition; or
    c. process enhancements to ensure the maintenance of asset health and to collect improved asset data which improves the understanding of asset condition and optimising data-driven intervention strategies.

ii. Ofgem also comment in paragraph 3.43 of the ET Annex that in certain instances Ofgem has relied on a network company's Engineering Justification Papers (EJP) to come to a view of appropriate allowances. However, the EJP Guidance published by Ofgem on 19 September 2019 explains that as part of their Business Plan submissions "*network companies are required to provide Engineering Justification Papers which set out the scope, costs and benefits for major projects or aggregated investment programmes aimed at improving asset health"* and the costs associated with network operating activities are not major projects and do not improve asset health, instead they *maintain* asset health. We therefore did not provide EJPs for our network operating costs, except for an element of capital expenditure recorded in BPDT table C2.24 Legal and Safety. Considering EJPs were being used to inform the assessment of the network companies' operating costs, it is a concern to us that a request was never made by Ofgem for an EJP covering our network operating costs if, despite the published guidance, Ofgem believed these to be necessary.

2.84 Notwithstanding the clearly different approaches to justification by SPT and analysis by Ofgem of our network costs, as well as the prolonged period of time between submission of our Business Plan and the publication of Ofgem's Draft Determination, we note that we received no Supplementary Questions ("SQs") from Ofgem regarding network operating costs. This does not seem to be proportionate when considered against the large disallowance made to our network operating costs by Ofgem and points to a lack of transparency in the assessment process prior to draft determination.

2.85 We discuss in detail the network operating cost tables, the cost reduction applied by Ofgem when applying unit cost models, why areas of expenditure have increased between RIIO-T1 and RIIO-T2, and why these cost reductions are unjustified in Annex 3 Network Operating Costs Analysis.

2.86 In summary the errors in Ofgem's analysis of the network operating costs tables are as follows:

C2.20 Faults

2.87 We submitted a Business Plan which requires investment of £19.8m to carry out activities recorded in the faults table which has been reduced in the Draft Determination to a proposed allowance of £12.3m.

2.88 SPT costs for RIIO-T1 are actual costs associated with faults. The forecast cost submitted for RIIO-T2 are all areas of reactive capital which includes faults. The disaggregation of costs by asset category into voltages and associated volumes is notional as this cannot be predicted with any accuracy. When considering these costs, they should be considered on an annualised basis by asset type. The Ofgem requirement was to split this activity by asset type and by voltage. Due to the unpredictability of faults and related activity this invalidates the perceived accuracy of greater disaggregation and unit cost analysis. This is discussed further in Annex 3 Network Operating Costs Analysis.

C2.21 Inspections

2.89 We submitted a Business Plan which requires investment of £7.4m to carry out inspection activities in line with our statutory duties, the condition of our assets and the increasing need for asset data to inform investment decisions. This has been reduced by Ofgem to an allowance of £5.5m.

2.90 The cost assessment by Ofgem has assumed year on year the nature of activity between RIIO-T1 and RIIO-T2 will be the same. This approach is flawed, as network operators need to be able to be flexible in their approach to surveillance of their assets and make considered changes to their practices and therefore incur additional, efficient, costs. The unit cost assessment carried out by Ofgem precludes the network operator from making these necessary changes. The requirement by Ofgem to report multiple activities on an asset as a volume of 1 artificially inflates unit costs in the analysis. This is discussed further in Annex 3 Network Operating Costs Analysis.

C2.22 Repairs and maintenance

2.91 We submitted a Business Plan which requires investment of £48.6m to carry out maintenance activities in line with ASSET-01-028 Issue 1: SPT Plant Maintenance Policy, ASSET-01-029 Issue 1: SPT Overhead Line Inspection and Condition Assessment Policy and CAB-01-007 Issue 3: Cable Maintenance and Inspection Policy which has been reduced by Ofgem to an allowance of £41.8m.

2.92 The cost assessment by Ofgem has assumed year on year the nature of activity between RIIO-T1 and RIIO-T2 will be the same. This approach is flawed, as network operators need to be able to be flexible in their approach to maintaining their assets and make considered changes to their practices and therefore incur additional, efficient, costs. The unit cost assessment carried out by Ofgem precludes the network operator from making these necessary changes. The requirement by Ofgem to report multiple activities on an asset as a volume of 1 artificially inflates unit costs in the analysis. This is discussed further in Annex 3 Network Operating Costs Analysis.

C2.23 Vegetation management

2.93 We submitted a Business Plan which requires investment of £2m for vegetation management activities in line with OHL-01-005 Issue 5 Tree Management Policy for ESQCR Compliance and OHL-03-080 Issue 7 Specification for Overhead Line Vegetation Management Works which has been reduced to a proposed allowance of £1.4m

2.94 The requirement by Ofgem as outlined in the Guidance on Business Plan Data Templates Version 1.4 to split vegetation management costs by voltage into spans inspected and spans cut, has led to the costs for RIIO-T1 and RIIO-T2 being presented slightly differently, to ensure it is in line with Ofgem's guidance. This is due to the different granularity of data required by the reporting requirements between RIIO-T1 and RIIO-T2 and has led to a disallowance. Unit cost analysis for vegetation management should consider the total costs and volumes for all activities as a whole in any year and not per activity, per voltage. This is discussed further in Annex 3 Network Operating Costs Analysis.

C2.24 Legal and Safety

2.95 We submitted a Business Plan which requires investment of £20.5m to carry out activities reported in the BPDT C2.24 Legal and Safety table which has been reduced by Ofgem to an allowance of £12.9m. Ofgem's unit cost analysis has compared RIIO-T2 operational and capital costs against RIIO-T1 operational costs. This therefore invalidates the analysis, because RIIO-T2 capital costs need to be removed for the benchmarking to be accurate. This is discussed further in Annex 3 Network Operating Costs Analysis along with unit cost analysis following removal of RIIO-T2 capital costs.

Independent review of Ofgem's cost assessment

2.96 We employed independent economic consultants NERA to carry out a review of the assessment methodology employed by Ofgem and the outcome of the assessment which has been used to set SPT's Network Operating Costs allowance. They concluded the assessment carried out by Ofgem is "entirely mechanistic and fails to analyse the reason for changes in unit costs over time" and the analysis includes a "downward bias" This is due to Ofgem assigning mechanistically, the lowest unit cost in either RIIO-T1 or RIIO-T2 for an activity and using this to set the allowance in RIIO-T2. This method therefore accepts that our unit costs for some activities in RIIO-T2 can go down however, does not accept that for other activities unit costs may rise and therefore has a downward bias.

2.97 NERA have carried out additional analysis using methods which remove the downward bias applied by Ofgem modelling. The first analysis calculated the unit costs using the average unit cost of the RIIO-T1 actual and RIIO-T2 forecast costs multiplied by the RIIO-T2 volumes and for cost categories where Ofgem uses average annual costs, the average annual costs in RIIO-T1 actual and RIIO-T2 forecast costs are used to calculate allowances. The second approach uses the RIIO-T1 unit cost multiplied by the RIIO-T2 volumes and where Ofgem uses average annual costs, the average annual costs in RIIO-T1 actual are used to calculate allowances. Modelling our costs in this manner would lead to allowances significantly higher than the Network Operating Costs forecast in our Business Plan. NERA then states, "There is no evidence to suggest that SPT's NOCs expenditure projections are unreasonable, and pending any different form of analysis that suggests otherwise, they should be allowed in full."

SPTQ15. Do you agree with our proposed allowances in relation to indirect operational expenditure? If not, please outline why.

2.98 Our review has concluded that Ofgem's Assessment of the TOs' Indirect Costs is extremely unreliable and its proposal to disallow large portions of TOs' CAI and BSC is flawed.

2.99 A more reliable approach to setting opex allowances would be to set allowances based on current levels of indirect costs for each company, with indexation over time for inflation, RPEs, ongoing productivity and (if appropriate) changes in capex due to changing workload requirements.

2.100 We commissioned NERA to review the draft determination proposals and their report is provided as in Annex 3 of this submission. The report concludes that Ofgem's statistical models are not sufficiently reliable to support its conclusions on the efficient levels of Indirect costs that SPT requires over the RIIO-T2 control period. Also due to the small sample size and the wide variation in the TOs' scale, there is a wide range of uncertainty around the degree to which the TOs' "efficient costs" vary from their business plan forecasts. In their report NERA identify a number of other regression model specifications which could also provide a basis for explaining variation in the TOs' costs and predicting their costs over the T2 period

2.101 Ofgem are placing unprecedented reliance on regression modelling for setting indirect allowances for the transmission sector. At past price reviews, due to the limited comparators, Ofgem did not conducted comparative benchmarking modelling to assess TOs' efficiency and set allowances for CAI and made only limited use of it for BSC. Ofgem's own reasoning for such an approach was to avoid the risk of setting allowances using models which would be extremely sensitive to changes in model specification, data error, inherent differences between companies etc.

2.102 It is of significant concern Ofgem is relying almost solely on a comparative benchmarking approach despite previously ruling out this form of econometric modelling, due to its limitations, particularly from only four cross-sectoral observations.

2.103 This approach also contradicts the approach used for assessment of other cost areas such as NOCs, which relies upon an assessment of individual TOs' historical and forecast costs.

2.104 We have set out the reasoning of why the current approach is unreliable below.

Ofgem's comparative benchmarking of indirect costs relies on an extremely small dataset

2.105 Ofgem has set allowances for indirect costs (both BSCs and CAI) using regressions, estimated using historical data from RIIO-T1 which equates to 6 years and using only four cross-sectional observations, the three TO's along with the Gas transmission operator. To apply such techniques to set allowances risks setting allowances using models which are extremely sensitive to changes in model specification, data error, differences between companies that are not explained by the available drivers, etc. As a result, Ofgem cannot be certain that about the conclusions from the modelling performed to set T2 allowances for indirect expenditure.

Alternative regression models that pass Ofgem's model selection criteria show a wide range of efficient costs for the TOs

2.106 What cannot be argued against is that the four TOs which have been benchmarked by Ofgem are very different sizes and the Scottish TOs operate much smaller networks over a smaller area than that of National Grid from both gas and electricity. Given these differences in scale, how the regression modelling accounts for differences in the cost function, in other words the structural relationship between cost drivers and modelled costs, across companies becomes a material determinant of modelled costs for individual companies over RIIO-T2. Ofgem assumes a Cobb-Douglas cost function in its models which imposes a single form of cost structure for all companies regardless of size. This assumption appears unlikely to be valid in reality. To test this NERA have experimented with a number of different ways of controlling for alternative cost functions, by testing linear models, quadratic terms as well as interaction terms - details of which can be found in the attached report[29]. Through these sensitivities, NERA have found that the modelled disallowance of the TOs' BSCs and CAI, defined by the difference between modelled costs and Business Plan forecasts, varies materially depending on these alternative approaches. Hence, due to the small sample size and the wide variation in the TOs' scale, there is a wide range of uncertainty around the degree to which the TOs' "efficient costs" vary from their Business Plan forecasts.

2.107 Ofgem has also considered only a very narrow range of cost drivers, which it appraises against a series of statistical tests. NERA have identified a number of other regression model specifications which could also provide a basis for explaining variation in the TOs' costs and predicting their costs over the T2 period. These alternative modelling specifications also meet the model selection criteria set out by Ofgem and its advisors (ECA) and show a wide variation in the implied disallowances over the T2 control period. These sensitivities further illustrate the wide range of uncertainty around the degree to which the TOs' "efficient costs" over the T2 period vary from their Business Plan forecasts. This would suggest that to focus solely on the output of one model as per Ofgem's approach is incorrect and will lead to flawed conclusions.

[29] NERA report: Response to Ofgem's RIIO-ET2 and GT2 Draft Determination on Opex Cost Assessment

Statistical evidence shows that Ofgem's modelling is mis-specified

2.108 While the modelling Ofgem has conducted is highly sensitive to different choices of drivers and changes in the way scale economies are specified above, NERA has also provided evidence that the models relied upon by Ofgem to set allowances also suffer from a number of statistical problems. These problems undermine the robustness of Ofgem's modelling as a means of predicting efficient costs for the T2 control period.

2.109 Firstly, Ofgem has pooled data on all four TOs into a single model, encompassing both NGGT (the gas TO) and the three electricity TOs. Ofgem is therefore making an assumption that the differences between the indirect costs incurred by these different types of business, using fundamentally different technologies, can be adequately controlled by using a simple statistical model. It has failed adequately to test this hypothesis. Instead, modelling undertaken by NERA provides evidence that the gas and electricity TOs do not have comparable cost structures, indicating that Ofgem's models are mis-specified. For instance, when running Ofgem's preferred CAI model on ET only, the regression coefficient on Capex is no longer significant (MEAV only at 5 per cent significance level). Likewise, for BSC we find that an interaction terms between the GT dummy and the cost drivers are also statistically significant. This suggests that Ofgem may be failing to capture differences in the relationship between BSC and its choice of drivers between ET and GT.

2.110 The model Ofgem has used to set allowances also fails the "Ramsey RESET" test, which is an important test for model mis-specification[30.] Despite statements from ECA and Ofgem's academic advisor (Andrew Smith)[31,] this is an important test for model mis-specification. In failing the "Ramsey RESET" test, this identifies non-linearities in the relationships between costs and Ofgem's selected drivers for which the model fails to account. The consequence of this failure is that a bias may be introduced in the modelled coefficients resulting in the modelled costs for individual TOs being materially over or under stated.

2.111 Ofgem also uses "panel" data to estimate regression equations, containing observations on multiple (four) companies over multiple (six) years. With panel data, a number of alternative regression techniques are available, not just the standard "Ordinary Least Squares" ("OLS") approach used by Ofgem. Standard econometric tests can inform the choice between these alternative statistical approaches. While the choice between these alternatives may not be clear-cut in small samples, standard statistical tests indicate that a "random effects" or "fixed effects" estimator may be more robust than OLS. Despite this evidence and failing the tests[32] Ofgem has ignored the results for its chosen regression models and retained a standard OLS approach. Failure to account for the panel structure of the data suggests that Ofgem's estimate of modelled costs are not correctly estimating individual TOs' inefficiency because it conflates efficiency with company-specific effects. Running these alternative models shows a wide range of sensitivity to modelled costs over the T2 period, which further undermines the reliability of Ofgem's conclusion to disallow some portion of the TOs' indirect forecasts. This additional evidence should be used by Ofgem in relation to their cost assessment process.

Ofgem's models use endogenous cost drivers, creating statistical bias and preventing them from identifying efficient levels of TOs' costs

2.112 Another flaw in Ofgem's models is the "endogenous" nature of cost drivers it has used to explain variation in costs. For instance, Ofgem has used (amongst other drivers) Totex and the number of FTE employees to explain indirect costs. These are endogenous, as they are controllable by the company and may both influence and be influenced by the dependent variable in Ofgem's regressions.

2.113 A well-known feature of OLS regression estimators is that, when applied with endogenous cost drivers, they generate biased coefficient estimates. Ofgem's use of endogenous cost drivers will have resulted in biased coefficients, and inaccurate estimates of TOs' modelled costs over the T2 control period.

[30] ECA (7 May 2020), RIIO-GD2 and T2: BSC and CAI assessment methodology, Methodology Paper, Table 13 and p.56-57 (BSC) and Table 18, p.63-64 (CAI).
[31] NERA report: Response to Ofgem's RIIO-ET2 and GT2 Draft Determination on Opex Cost Assessment section 4.3.3
[32] ECA (7 May 2020), RIIO-GD2 and T2: BSC and CAI assessment methodology, Methodology Paper, Table 13, p.56 and Table 18, p.63.

2.114 Put differently, a major reason for Ofgem using comparative benchmarking to compare companies' costs is to set allowances that reflect "efficient" costs, and do not include any inefficiency. Under Ofgem's approach, companies could increase expenditure or employ more staff to perform functions that are not required to meet the needs of customers, and the inclusion of the Totex and FTE drivers would provide additional allowances as a result. Their inclusion therefore injects bias into the statistical modelling and undermines the model's usefulness as a way of identifying efficient costs.

Other considerations

2.115 Ofgem's approach in the Draft Determination is also at odds with its own indicated approach in the June Consultation (which we comment on above in our overarching comments to this Chapter). This cost assessment consultation stated that Ofgem's intent was to "limit the use of drivers that are specific to network sectors, such as network length and MEAV". In reality, Ofgem has only used cost drivers that are materially specific to networks e.g. MEAV. Given the emphasis that has been placed on this driver, we are worried by the lack of consistency in the definition of MEAV and the lack of instructions for its calculation. Such inconsistency in a key driver could easily skew the analysis and further reduces the reliability of the conclusions that Ofgem draws from its model. This issue is exacerbated by the use of companies' own unit costs which means a "theoretical" inefficient company would benefit from this approach.

2.116 We also believe that Ofgem's modelling in the draft determination for Closely Associated Indirects ("CAIs") is incorrect as Ofgem are trying to derive a view of efficiency against a "Baseline" view of the capital expenditure that will arise during RIIO-T2. This is incorrect as the 'baseline' does not reflect projects to be funded through the proposed RIIO-T2 uncertainty mechanisms. This is only a cost classification partition as there is considerable certainty that these projects will materialise. The uncertainly is mainly on the eventual specification and therefore associated spend. However, to ensure that these projects can be delivered in a timely manner, CAI expenditure will be required early in the period to ensure correct design, engineering requirements and advanced planning consent / land access authorisation. Currently Ofgem are not reviewing CAIs against the appropriate cost base. Further to this they are also then removing further levels of expenditure in the form of a workload adjustment that is further eroding SPT's ability to accommodate the higher project activity and expenditure levels. This can be illustrated through the outcome of Ofgem's modelling as per the Draft Determination, where SPT is currently deemed to be efficient in the early years of RIIO-2 however inefficient in the final three years mostly due to the baseline capex forecast which as expected will decrease through the period as uncertainty increases.

2.117 Indeed, ECA (Ofgem's economic advisors supporting the indirect cost benchmarking for RIIO-T2) seem to share our concerns that this modelling is not reliable. For example, with regards to its CAI regression model ECA states the following:

> "*we include a discussion of each network's results, which require further scrutiny. We consider the model appropriate for forming the basis of an efficiency challenge, but further investigation (outside of the modelling process) is needed by Ofgem before it takes its decision on where to set the allowances, particularly for NGET and SHET*".[33]

2.118 Ofgem's proposal to disallow large amounts of TOs' indirect expenditure is therefore unreliable. NERA in its report finds Ofgem has no substantive evidence that the levels of expenditure currently proposed by the TOs include any element of inefficiency[34].

2.119 For indirect costs, the ranges of uncertainty around forecast costs emerging from a number of regression models, which are no less reliable than Ofgem's model, means it cannot be certain there is any degree of inefficiency built into TOs' current and forecast costs.

[33] ECA (7 May 2020), RIIO-GD2 and T2: BSC and CAI assessment methodology, Methodology Paper, p. xii.
[34] NERA report: Response to Ofgem's RIIO-ET2 and GT2 Draft Determination on Opex Cost Assessment section 5.1

Modelling exceptions

2.120 Ofgem has asked the companies to provide examples of areas where the current modelling approach cannot reasonably predict the future outcome for companies, with Ofgem allowing almost all expenditure against both IT & Insurance for SPT. Therefore, we believe that there are two ways in which any modelling cannot reasonably predict future expenditure: either (i) as the historic costs do not match those costs that will be incurred in the future or (ii) where there is an inherent difference in the companies that are being compared.

2.121 On this basis, we believe the following costs should also be subject to a separate review and not be included as part of the overall efficiency reduction:

- In sourcing / Outsourcing organisational differences between TOs
    - In our Business Plan, within the “delivering our network “chapter, we have explained how our disaggregated delivery model has provided benefits to the end consumer through efficiency when compared with the historical UK industry approach to delivering projects.
    - A knock-on effect of this approach is that SPT is required to put in place internal resources for activities such as design and project management that otherwise would be outsourced.
    - This internal resource allows us to deliver our projects and outputs more efficiently in “direct cost” terms, while increasing our closely associated indirect costs in the process.
    - A further knock-on to this process is the role of our procurement department, which is instrumental in ensuring that our delivery approach is achievable by ensuring that at each stage of the construction process our contractors have the equipment required at the lowest possible cost.
    - Therefore, at a total Totex level, both aspects will “net off” so no extra costs are required for delivery and, when coupled with the benefits we have discussed in the direct costs sections, deliver a better outcome for the consumer.
    - The current approach that Ofgem has taken to cost assessment of the various expenditure categories does not take account of this overall approach and the impact this has on various areas of costs benchmarking.
    - We therefore believe that the efficiencies applied to the Procurement function should be removed due to the fact the model used by SPT is different from our peers and the modelling approach applied has not taken account of this.
    - Furthermore, the impact on the categories of project management and EM&CS cannot be ignored and further engagement is required to ensure that SPT is not unfairly penalised through the cost assessment approach currently adopted by Ofgem.

- Areas of Divergence from Historic Performance
    - As stated in our Business Plan, in light of the anticipated number of retirees, leavers through natural attrition, and progression of employees into skilled roles, there will be a significant requirement to recruit and train new employees during the RIIO-T2 period. This represents 162 new employees during the period, or 25% of our current workforce, with 80 new graduates, 30 new apprentices and 52 skilled individuals direct from the wider market. As a consequence, the level of investment in recruitment and training required to ensure that the right resources are in the right place at the right time is of significant importance. Therefore, we do not agree with Ofgem’s simplistic approach of applying significant reductions on the areas of Operational Training and recruitment area of HR on the basis of lower costs being incurred historically in these areas. In doing so, this will hinder our ability to continue to deliver outputs as required during RIIO-T2 and into the future. As a result, we believe that special consideration should be given to this area, with no reductions applied to operational training and to the level of HR to take account of the recruitment function within HR.

    - As set out within the Draft Determination, Ofgem intends to make extensive use of re-openers through RIIO-T2, to allow a company the flexibility to deliver additional projects as and when required to help facilitate the transition to Net Zero. As a consequence of this approach, the engagement between the companies and Ofgem will increase to a level not seen historically in order to ensure that there is no delay in such projects. This engagement will inevitability increase the resource requirements from the regulation teams within the network companies to facilitate this new way of working. As a result, we do not believe that the current proposed reductions of regulation expenditure of 33% are appropriate or justified.

- Wayleave expenditure
  - We do not believe that wayleaves costs can be assessed correctly per the model adopted by Ofgem and these costs should be subject to a separate assessment.
  - Voluntary wayleaves are personal agreements with landowners and occupiers, giving network companies the right to install and to access overhead lines and underground cables. Although necessary wayleaves are binding on successors in title, they are not capable of registration or recording and can only be obtained in certain circumstances.
  - Therefore, given the significance and importance of the transmission network, we always prefer to negotiate a more secure land right known as a servitude which provides the additional protection. We generally pay the landowners and occupiers for wayleave rights with an annual payment calculated to match the owner or occupier's loss due to our equipment being on their [redacted]
  - [redacted]

  - Per the RIG's, wayleave costs are currently reported against Engineering Management & Clerical Support (EM&CS), and as such have been subject to an overall reduction of 23%. Given the nature of these costs we do not consider that these should be reduced as these costs will be higher during RIIO-T2 than in RIIO-T1.
  - We also note that Ofgem has disallowed all servitude expenditure in the Draft Determination, which will lead to a substantial increase in wayleaves costs if not corrected.
  - We have proposed a reopener for these costs based on the current trends observed across the UK in terms of attitudes to wayleave payments from landowner. We note that this reopener has currently not been accepted by Ofgem as there is a request for additional evidence which we plan to provide as part of our response.

- Environmental Action Plan ("EAP")
  - EAP costs have been agreed in other parts of the Draft Determination that are not accounted for in Ofgem's cost assessment approach.
  - As these costs have been accepted we believe that they have been subject to a separate assessment and should be excluded from the benchmarking approach currently applied by Ofgem.

SPTQ16. Do you have any other comments on our proposed allowances for SPT?

2.122 We have provided extensive commentary on Ofgem's proposed allowances in responses to the relevant questions.

Chapter 3: Finance

Introduction

3.1 Ofgem's proposals on finance contained in the Draft Determination (DD) for RIIO-T2 reduce the cost of capital to an all-time low for GB networks. Ofgem's proposed finance package does not reflect the increased level of risk that TOs are exposed to relative to RIIO-T1, benchmarks poorly with other comparators and includes unjustified adjustments.

3.2 A stable regulatory regime and reasonable returns are essential at a time when greater than ever investment is required in the UK to meet GB's Net Zero objectives. The financial package must be fair to consumers and investors; ensuring the UK can attract the necessary investment and companies retain their Investment Grade credit ratings. Ofgem's cost of equity allowance for Electricity Transmission lies below the median of European countries and on an international basis is much lower when compared to the returns available in the US. Ofgem's proposed cost of equity puts at risk the significant investment required to ensure network companies can enable the transition to Net Zero as quickly as possible.

3.3 Fairness to consumers and fairness to investors are not and should not be mutually exclusive, and Ofgem has a duty to balance these objectives. It is in the interests of consumers that utilities can attract the necessary finance. The interests of future consumers is of particular relevance. Setting an unduly low cost of capital may be viewed, (erroneously) as in the interests of present consumers. However, Ofgem's proposals will damage confidence in the regulatory regime and therefore risks leading to a higher cost of capital in the future. This is not in the longer-term interest of consumers.

3.4 It is clear that Ofgem has set out to reduce the cost of capital to a very low level. In so doing, it seems that Ofgem has approached assessment of many of the individual "building blocks" of the cost of capital with that objective in mind. Ofgem repeatedly gives insufficient weight to cogent evidence that points to a higher cost of equity whilst giving undue weight to less cogent evidence that points to a lower cost of equity. As an example, Ofgem gives excessive weight to evidence about OFTO IRRs, and investor forecasts. In adopting this approach Ofgem falls into error. More importantly, we believe Ofgem's Cost of Equity proposals are divorced from the real world and we do not believe reflect 'real life' investors' expectations, especially in light of the financial uncertainty we face as a result of BREXIT and COVID-19.

3.5 In addition, the proposals materially increase risks for shareholders and reduce any prospect of rewards for achieving outcomes that provide demonstrable benefits consistent with our legal duties and objectives.

3.6 In this finance chapter of our response to the draft determination, we set out objective independent evidence for Ofgem to consider in advance of setting the final determination (see Table 3 for summary). We have material concerns that, if implemented, the Draft Determination puts at risk SPT's ability to adhere to its statutory duties.

3.7 We want to work constructively with Ofgem in order to resolve these differences and, at a minimum, ensure that we have worked together to properly narrow and focus the areas of dispute. We are committed to continue to work constructively with Ofgem on these matters.

3.8 In developing our response to Ofgem's Draft Determination finance proposals we have included extensive external independent expert evidence. Our response below reflects the evidence from these commissioned reports. This includes an independent assessment on the Cost of Capital, with NERA's analysis supporting a Cost of Equity range of 5.91-7.16% (real-CPIH) and Oxera's analysis supporting a Cost of Equity range of 6.00-7.08% (real-CPIH). The summary of these reports and their key findings can be seen in the Table 3 below. The reports can be found within Annex 4 of this Draft Determination consultation response.

Table 3: Independent external evidence

Report	Independent View	Commissioned by	Key Findings
The cost of equity for RIIO-2 – Q3 2020 Update	OXERA	ENA	Report serves as an update to the 2019 Oxera report, examining financial market data through 31 July 2020 and updating earlier analysis. Criticise Ofgem's use underestimated real TMR due to unreliable deflationary and averaging approach, and Ofgem's use of water network comparators in their beta analysis. Oxera's updated work, along with the updated versions of both Oxera's and Ofgem's cross-checks, supports a cost of equity in the range of 6.00–7.08% (real-CPIH).
Asset risk premium relative to debt risk premium	OXERA	ENA	Report shows that Ofgem's midpoint allowance falls below the 15th percentile of the market data, implying that Ofgem's allowance is low compared to market evidence. The ARP−DRP differential has a role above and beyond a cross-check in the estimation of cost of equity parameters. In particular, the ARP−DRP framework provides important additional information for the assessment of financeability.
Cost of Capital for SPT in RIIO-T2	NERA	SPT	Reviews Ofgem's cost of capital assessment as published in its DD for RIIO-T2 and set out NERA's own market-based assessment of SPT's cost of capital. Main arguments are that Ofgem have: underestimated real TMR due to unreliable deflationary and averaging approach; underestimated beta due to analysis emphasising GB water networks rather than focussing on UK & European energy networks; and used unreliable cross-checks, with some even pointing to a higher cost of equity than that implied by Ofgem's CAPM. NERA's analysis supports a Cost of Equity range of 5.91-7.16% (real-CPIH).
Review of Ofgem's DD Additional costs of borrowing, and deflating nominal iBoxx	NERA	ENA	NERA respond to Ofgem's estimation of Additional Costs of Borrowing (including halo), as well as its approach to deflating nominal iBoxx. Finds support for additional costs of borrowing of 47-59 bps, including a NIP of 9bps, compared to Ofgem's DD of 17 bps.
Cost of Debt at RIIO 2	NERA	ENA	NERA model expected Cost of Debt performance over RIIO-2 under different indexation mechanisms and critiques Ofgem's use of Utilities index, which NERA shows exposes companies to rating risk over RIIO-2.
Further Comment on Ofgem's Proposal to Adjust Baseline Allowed Returns	Frontier Economics	ENA	Report responds to all of the points raised by Ofgem in response to Frontier's first report om this topic. Recent historical levels of outperformance are not representative of potential outperformance in RIIO-2. Proposal would: erode investor confidence and increase investor risk; weaken incentives for efficiency and innovation; and distort managerial incentives to invest.
RIIO-2: Prior Year Adjustments	First Economics	ENA	Challenges proposal from Ofgem to apply only an "interest rate" on prior year adjustments. Prior year adjustments to reflect TVM relating to expenditure items are adjusted at the allowed cost of capital.

3.9 This part of our response:

- Explains how Ofgem's approach to the assessment of the Cost of Equity for RIIO-T2 disregards cogent evidence that points to a higher Cost of Equity whilst taking into account irrelevant and less cogent evidence which supports a lower Cost of Equity;
- Includes extensive expert external independent evidence for Ofgem to consider in setting the WACC for the final determination;
- Challenges the errors made in the assessment of Total Market Returns and how the beta is calculated;
- Challenges the ad-hoc unjustified adjustments to the allowed cost of equity in relation to Ofgem's 'Allowed versus Expected returns' concept which contributes to the all-time low Cost of Capital;
- Explains that the real RFR under a CPIH-based price control should be set based on yields on 20-year nominal UK gilts and deflated by expected CPIH inflation instead of ILG yields. Ofgem's reliance on an

alternative historic inflation series understates the expected real TMR as it overstates historical inflation. The inflation series is based on back-cast data which the ONS consider to be unreliable;

- Summarises analysis by Oxera and NERA which demonstrate that the forward-looking cross checks, for the CAPM-implied Cost of Equity results, employed by Ofgem are unreliable.
- Demonstrates that the new index for Cost of Debt (iBoxx Utilities 10yr+) exposes network companies to under-recovery as it does not have a defined rating (other than investment grade), whereas the existing index is regularly updated to be consistent with Ofgem's approach to financeability.
- Evidences that the proposal to set WACC at the same level across Gas and Electricity is not consistent with Ofgem's own reasoning for providing a lower level of gearing;
- Evidences that notional gearing is being used as a financeability lever and not as an independent cross check on the suitability of the proposed industry WACC; and
- Evidences that the alignment of Cost of Equity with the water sector is also incorrect due to the lower risk in the water sector.

Cost of Equity

3.10 Ofgem's approach to the assessment of the Cost of Equity for RIIO-T2 is not based on all the available evidence. Ultimately it has been set at a level which will disrupt the efficient financing of the GB's network businesses, limiting the sector's ability to support the country's transition to Net Zero at this key time. The lack of adequate incentives to investors to commit to crucial investment in the UK and create the required stimulus to enable Net Zero can be evidenced by recent investor commentary, for example on the 27th August 2020, Barclays published an investor note which stated it would expect National Grid to trade at a 5% discount to RAB based on the proposed DD parameters. On the same day, S&P have affirmed they had changed National Grid plc's outlook to negative, the key reasons for the negative outlook are the impact of Covid-19 and tougher conditions in the next regulatory period in the UK.

3.11 In the Draft Determination, Ofgem has retained its three-step approach to estimating the cost of equity. In Step 1, Ofgem estimate the Cost of Equity implied by evidence from the Capital Asset Pricing Model (CAPM). The CAPM results are then cross-checked against different measures of equity returns in Step 2. Lastly, in Step 3 Ofgem apply a downwards arbitrary 'Outperformance Wedge' adjustment to the underlying Cost of Equity estimate, resulting in the equity allowance lying towards the low end of the CAPM range. We believe this outperformance wedge is fundamentally flawed and incorrect as detailed within Frontier Economics' report titled "*Further Comment on Ofgem's Proposal to Adjust Baseline Allowed Returns*".

3.12 The further decline in the allowed baseline equity returns from the SSMD to the 3.70% in the Draft Determination have resulted in the lowest baseline equity returns since privatisation, being set inexplicably 20bps lower than that offered to the lower risk GB water sector for the PR19 controls. It also falls well short of the 6.5% in our Supplementary Business Plan submitted in December 2019 which was based on extensive and detailed independent evidence setting out why this was an appropriate level of required return for investing in the GB electricity sector.

3.13 In addition to the errors made in estimating the Total Market Return (namely, the relevant historical inflation series and averaging methods) and the use of incorrect empirical comparators used in the beta assessment, there are also flawed ad-hoc adjustments that result in an allowed Cost of Equity being set materially lower than the evidence indicates and at a level insufficient to attract investment in the sector at such a crucial time. This has been justified with extensive and detailed evidence as set out in the main body of our Business Plan, the finance annex and also in NERA's August 2020 Cost of Capital report.

Step 1: CAPM Evidence

Risk free rate (RFR)

3.14 The real RFR under a CPIH-based price control should be set based on yields on 20-year nominal UK gilts and deflated by expected CPIH inflation instead of ILG yields at the same maturity, as this approach would provide a more objective and stable measure of the real RFR, and thus is more appropriate for Ofgem's Cost of Equity index. ILGs with long maturities are embedded with a liquidity premium and may be further affected by "structural imbalances" driven by excess demand from institutional investors, such as pension funds. ILGs yields have been volatile over time, especially recently from the impacts from Brexit and COVID-19.

3.15 Recognising the enduring debate within regulatory reviews around whether nominal gilts or ILGs alone provide the best measure of the RFR, with both instruments affected by factors which are difficult to quantify, we would also advocate for an alternative approach established by Oxera.[35] This was considered by Oxera in their exploration into the CMA's concerns around the perceived positive relationship between the WACC and gearing seen in the NERL redetermination, in violation of the Modigliani-Miller (MM) theorem that the cost of capital is invariant with respect to the level of gearing. Oxera demonstrates that the use of spot yields on ILGs leads to an under-estimate of the RFR in the CAPM framework due to their unique convenience characteristics and that they do not represent the risk-free financing rates for non-sovereign investors. With these issues in mind, Oxera presents a cogent alternative approach for setting the RFR by either basing it on yields from the 'highest quality' corporate bonds (i.e. the iBoxx AAA-rated corporate bonds with 15yr+ maturity index), with an adjustment to account for the non-zero default risk premium reflected in the yields of these bonds, or by adding a 50 to 100bps premium on top of the spot yield for ILGs to account for the historic spreads of AAA-rated corporate bonds relative to government bonds. The latter approach is consistent with the approach taken by investment banking analysts.

3.16 Oxera's critique reveals a fundamental error of approach made by Ofgem when estimating the real RFR (i.e. using spot ILG yields). Given the debate between the use of ILG and nominal gilts when setting the RFR, Oxera's alternative approach provides a practical solution. It should also resolve the issue observed by the CMA in its NERL redetermination that the WACC apparently increases with gearing where using a spot ILG[36] (see FQ4 for more detail).

Total Market Return (TMR)

3.17 Ofgem has retained its SSMD range for the TMR in the DD. Ofgem has made several crucial errors in its approach to deriving the recommended TMR range, resulting in a significantly underestimated TMR estimate and ultimately a cost of equity set at an unreasonable and unrealistically low level based on the available evidence.

3.18 Ofgem has erroneously not relied on the most robust historical inflation measure available when deflating nominal historical returns. Instead they have imposed a 'back-cast' CPI inflation series published in the Bank of England's (BoE's) 'Millennium dataset', which produces unreliable and overstated estimates of historical CPI inflation, leading to a materially understated historical TMR range when stated in real CPIH-terms. This series is an estimate of historical CPI inflation as no outturn data for CPI exists before 1989 and the methodology behind its computation results in it being more of a hybrid CPI/RPI index. The series methodology overstates the underlying CPI as it relies on a series for the years prior to 1947 (the Consumption Expenditure Deflator ("CED") series) which includes at least some of the upward biases from the RPI 'formula effect' – an interpretation which the Office for National Statistics (ONS) agree with[37] – and is a series that has been shown to have greater alignment to RPI (which is higher than CPI) rather than CPI.[38]

[35] Oxera (May 2020), 'Are sovereign yields the risk-free rate for the CAPM?', prepared for the Energy Networks Association,
[36] Competition and Markets Authority (2020), 'NATS (En Route) Plc /CAA Regulatory Appeal: Provisional findings report', 24 March (CMA NERL Provisional Findings), Appendix D para 4.
[37] Oxera, (November 2019), 'The cost of equity for RIIO-2: Q4 2019 update', prepared for ENA, p. 16
[38] Analysis by National Grid in their TMR report has shown that the average differential between CED and RPI is relatively small for the full period that both data sets are available. It is therefore likely that the CED series has been constructed using a methodology comparable to

It is also a measure that the ONS considers to be unsuitable for official uses as it is comprised of unreliable modelled estimates of CPI inflation for the period of 1950-88 which have since been superseded[39].

3.19 Instead, the historical RPI inflation series should be used as the basis for deflating historical nominal returns into real terms. The RPI series is a more accurate and reliable measure of UK historical inflation as it dates back to 1900 and is based on actual outturn data for the majority of the historical period since 1900, as opposed to the CPI series which primarily relies on estimates for the same period. Indeed, RPI inflation was the official measure of inflation in the UK for the majority of the historical period since 1900[40]. While the ONS has questioned the use of RPI as a forward-looking inflation index, they have not questioned its use for backward looking purposes, such as when looking at historical real market returns.[41] In addition, the ONS recently published a "Long term indicator of prices of consumer goods and services" which also uses RPI data as a measure of historical inflation.[42]

3.20 Additionally, with the switch to a CPIH based price control, a CPIH historical returns equivalent can be determined by applying an estimate of historical RPI-CPIH wedge based on the difference between RPI and CPI (using CPI as a proxy for CPIH) to the derived historical RPI-real returns range.

3.21 Ofgem rely on the UKRN report which applies an excessive 1% downward adjustment to the simple arithmetic mean return for alleged predictability of returns at long horizons. However, NERA find that evidence on returns predictability is highly contentious[43] and the UKRN authors ignore more established unbiased estimators developed by Blume and JKM for estimating unbiased estimators of the TMR for long investment horizons, which support a relatively modest adjustment (40bps) to the simple arithmetic return averages at the UKRN report's preferred 10-year investment horizon.[44] Regarding the appropriate approach to averaging historical returns, we continue to propose the approach recommended by NERA (and outlined in our Business Plan) of relying on overlapping arithmetic averages, 'Blume' and 'JKM' estimators to provide an unbiased estimate of expected returns over the RIIO-T2 period.[45] The Blume and JKM estimators are both weighted averages of the geometric and arithmetic means with greater weight placed on the arithmetic mean the longer the historical period used to estimate the TMR compared to the investment horizon. These have also been used by the CMA at recent reviews.[46]

3.22 NERA[47] has updated their historical TMR calculations from their November 2019 report, now using the 2020 DMS publication data for the UK equity market returns over the period 1900-2019, using the proposed estimators mentioned above and using two alternative sources of historical RPI inflation to derive average returns in real-RPI terms: (i) the RPI inflation reported in the DMS publication for the period 1900-1949 and official ONS RPI historical data for the period 1950 onwards; and (ii) the RPI inflation included in the Bank of England's Millennium Dataset. Both sources are based on official RPI data from the ONS for the period after 1950.

RPI and therefore will likely include at least some of the upward biases from the RPI formula effect, which would overstate CPI inflation. See: National Grid, 'Total Market Return, The consistency of long-run CPI and RPI inflation series in the UK, and their relative suitability for use in calculating the actual historic long-run average equity market return in the UK on a 'real' basis' **(National Grid TMR report)**, p.11 (https://www.nationalgridet.com/planning-together-riio/our-riio-2-business-plan-2021-2026/finance).

[39] The modelled CPI estimates for 1950 to 1987 are calculated based on 1988 to 1996 CPI data that has since been superseded. However, the estimates for 1950 to 1987 have not yet been updated to reflect the new CPI values for the period 1988 to 1996. In October 2019, the ONS expressly stated that these CPI values were not intended for official uses (i.e. they cannot be considered reliable for policy making) and that it plans to produce new indicative revised estimates for the CPI between 1950 and 1987 alongside the planned CPIH estimates, based on the corrected CPI data. See: National Grid TMR Report, page 33.

[40] Until 2003, the Bank of England used RPI for the purpose of inflation targeting, replacing it with CPI from 2003 onwards. Since 2003, RPI has been replaced by CPI. From 2011, RPI has also been replaced by CPI for the purpose of indexation of pensions for public sector employees. (Sources: HM Treasury (10 December 2003), Remit for the Monetary Policy Committee of the Bank of England and the New Inflation Target; Department for Work and Pensions and the Rt Hon Steve Webb (12 July 2010), Statement on moving to CPI as the measure of price inflation.)

[41] This is reinforced by the Bank of England using the RPI back series in its historical inflation calculator, the ONS preferring to use RPI for comparing the purchasing power of the pound over period of 1947 to 1988 and the close comparison of CEDs used in the UK's Blue Book National Accounts over 1947 to 1988 to the RPI series.
See: ENA, 19th June, Ofwat Price Determinations: Further submission by Energy Networks Association, p. 6 (https://assets.publishing.service.gov.uk/media/5eeb57fae90e07644fae4218/Energy_Networks_Association__3_.pdf)

[42] Available at ONS website: https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/cdko/mm23

[43] See: NERA (April 2019), 'Cost of Equity for SPT in RIIO-T2', Appendix C.3.1

[44] NERA (November 2019) 'Cost of Equity for SPT in RIIO-T2', section 8.5.1

[45] NERA (September 2020), 'Cost of Capital for SPT in RIIO-T2', section 2.2

[46] CMA (March 2014), 'NIE Limited price determination', London: The CMA, p. 13-27, Table 13.7 and CMA (March 2020), 'NERL Provisional Findings, table 12-14, p. 183

[47] NERA (September 2020), 'Cost of Capital for SPT in RIIO-T2', section 2.2

3.23 Assuming one to five year holding periods, which is supported by the empirical evidence on typical investor holding periods[48], NERA estimates an historical real TMR (RPI-deflated) range of 6.4-7.1%. NERA convert this range to a CPI equivalent by applying updated estimates of the historical RPI-CPI wedge of between 46 bps (calculated over the full historical period since 1950 when *some* CPI data is available) and 72 bps (calculated over the most recent period since 1988 when official CPI data is available). NERA arrives at CPI-deflated historical returns range of 6.9-7.8%[49], in line with that recommended in our Business Plan.

3.24 Separately, Oxera sets out the rationale for using arithmetic averages in setting the TMR in a regulatory setting. The rationale is that investors will use a discount rate (i.e. TMR) at least as high as the historical arithmetic average when taking capital budgeting based on arguments proposed by Cooper, who demonstrated that the discount rate investors should use to give an unbiased estimate of the present value of future cash flows will assume a TMR at least as high as the arithmetic average of historical returns.[50] Oxera's Cooper based approach provides a rationale for the use of an arithmetic average which would support values of between 7.2% to 7.8% in CPIH-deflated terms, which is towards the top-half of NERA's estimated Blume/JKM TMR range.[51]

3.25 For the reasons highlighted above, the methodological errors made by Ofgem have resulted in an understated historical TMR range when stated in real CPIH-terms, thereby resulting in a cost of equity which is downwardly biased. We rely on the more reliable long-run historical realised returns estimates produced by NERA as our primary source of evidence on the real TMR, which supports a real-CPIH expected TMR range of 6.9-7.8%.

3.26 We continue to consider estimates from NERA's Bank of England DGM as a suitable cross-check to the long-run historical TMR evidence. We note that the DGM model used by Ofgem in the SSMD has a different specification to that used by the Bank of England, using an understated dividend growth assumption by relying on UK GDP forecasts as a basis of short and long run dividend forecasts. This has led them to estimating a downward-biased estimate of the TMR.[52] As there has been no update of the Bank of England's DGM, we continue to rely on NERA's DGM evidence presented in their November 2019 report, which supports a real CPI-deflated TMR of 8.4-9.3%.[53] The forward-looking DGM estimates are therefore higher than NERA's historical TMR estimates and are in line with Oxera's DGM TMR estimate.[54]

3.27 As stated in our Business Plan, we consider that this evidence should be treated with caution, given the relative sensitivity of the results to the long-term dividend growth assumption. In recognising the benefit of predictability and stability in a regulatory framework, it is therefore appropriate to attribute more weight to evidence from historical realised returns than that of individual forward-looking projections. Ofgem gives too much weight to evidence which supports a low TMR and discount cogent evidence that points to a higher TMR.

Beta

3.28 Ofgem is incorrect in asserting that the systematic risk between water networks and GB energy networks are similar due to similarities in the regulatory framework, and that the pure-play GB water networks (Severn Trent (SVT) and United Utilities (UU)) are therefore appropriate comparators for estimating betas for pure-play GB energy networks.

3.29 We have detailed in our RIIO-T2 Business Plan why it is not appropriate to place weight on beta estimates from the listed UK water networks when selecting an asset beta for SPT.[55] Although water

[48] See: Roberge M., Flaherty J., Almeida R., Boyd A., 2017, Lengthening the Investment Time Horizon, p.2; Kay Review of UK Equity Markets and Long-Term Decision Making, Interim Report, Feb 2012; CFA UK response to the Kay Review of UK Equity Markets and Long-Term Decision Making – Call for Evidence; and Helm and Tindall, 2009, The evolution of infrastructure and utility ownership and implications, Oxford Review of Economic Policy, Vol 25, pp 411 – 434.
[49] NERA (September 2020), 'Cost of Capital for SPT in RIIO-T2', section 2.2
[50] Oxera (September 2020), 'The cost of equity for RIIO-2 – Q3 2020 Update', section 2.2.1
[51] NERA (September 2020), 'Cost of Capital for SPT in RIIO-T2', Table 2.6
[52] See: NERA (November 2019) Cost of Equity for SPT in RIIO-T2, Appendix A.2
[53] NERA (November 2019) Cost of Capital for SPT in RIIO-T2, p. 18.
[54] Oxera (September 2020), The cost of equity for RIIO-2 – Q3 2020 update, section 2.2.2.
[55] SPT (December 2019), 'RIIO-T2 Business Plan Submission – Finance annex', p. 14

networks are utilities and subject to a similar regulatory regime, they ultimately face a different set of business risks than energy networks, which face higher risk due to relative complexity of the investment programme; competition risks from Ofgem's on-shore competition models; and greater uncertainty over the future role of SPT in a decarbonised energy sector with prospects for decentralised generation with the transition to Net Zero. CEPA's own relative risk analysis also acknowledges that energy networks are be seen by investors as riskier than water networks.[56] The assertion that SPT face higher investment risk is also evidenced when looking at the higher capex/RAV ratios that SPT have compared to water networks (and GDNs).[57]

3.30 Additionally, the empirical historical beta analysis conducted by NERA[58] and Oxera[59] indicate that listed energy networks' (NG and SSE) asset betas have been consistently higher than those of water networks' (UU, SVT and PNN). The difference in risk profile can also be observed from the divergence in energy and water networks asset betas over the recent COVID-19 period. The empirical evidence here suggests that energy networks face higher systematic risk than water companies.

3.31 We disagree with CEPA's estimation methodology and comparator selection criteria for their European asset beta assessment, which have led to a range in line with those estimated for the GB water networks, resulting in Ofgem's incorrect conclusion that GB pure-play water networks should be used as primary evidence to inform GB energy network betas. CEPA's European sample includes the illiquid stock of Elia, and incorrectly excludes relevant close comparators of Acea and Naturgy despite both having sufficiently high regulated business share to meet CEPA's own criteria.

3.32 We consider that National Grid (NG) is the most direct comparator for SPT as relying on betas from GB water comparator companies will underestimate the beta for a pure-play GB energy network. Selecting an asset beta for SPT in line with that estimated for NG is therefore appropriate. We also consider that the asset beta analysis should include estimates derived from comparable European energy networks in order to broaden the sample, thereby improving the robustness of the beta assessment.

3.33 In regards to the estimation methodology, Ofgem's reliance on long-term estimation windows and averaging periods in their beta assessment (i.e. 10 years) ignores the existence of structural breaks, and results in equity beta estimates that fail to reflect the forward-looking risk faced by the regulated entity over the future price control period as they ignore changes in the risk of a company, changes in regulatory regime and risk, as well as changes to market conditions. This approach is also contrary to the CMA's approach at previous network price control appeals, including in their provisional findings for the NERL redetermination.

3.34 Adopting an estimation approach more in line with that employed by the CMA[60], NERA and Oxera both focus on 2 and 5-year estimation periods in their beta regressions, using daily data as these provide estimates with the lowest standard errors. NERA also focus on estimates based on 2 and 5 year averaging periods over those based on more recent averaging periods (i.e. spot or 1 year) in order to avoid placing undue weight on recent periods affected by the economic disruptive impact from the COVID-19 pandemic, as well as increased political and regulatory risks around the price control, which have emerged as increasingly important risk factors – both NERA and Oxera show that heightened political and regulatory risks will lead to downwardly biased beta estimates.[61,62] In the de-gearing process, NERA utilise the book value of debt as opposed to market value of debt, which is used by Ofgem. As detailed by NERA, Ofgem's adjustment (known as the market value factor (MVF) adjustment) is not conceptually correct in the context of a regulated entity and should not be used when de-gearing raw equity betas. The prior claim by debtholders does not increase proportionately where debt interest costs decline as Ofgem continues to allow companies to recover historical debt coupon costs on average.[63]

[56] CEPA (9 July 2020), RIIO-2: Beta estimation issues, p.38
[57] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 3.5
[58] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 3.3
[59] Oxera (September 2020), The cost of equity for RIIO-2 – Q3 2020 update, section 3.3
[60] The CMA notes that the use of 2-year and 5-year periods for beta measurement is consistent with normal practice, i.e. betas calculated based on share prices over a 2-year period or a 5-year period. When using weekly data, it gives the most weight to the five-year weekly betas, because of high standard errors around 2-year weekly betas, and also because some of these 2-year weekly betas appeared to be outliers. See: CMA (March 2020), NATS provisional findings, para.12.82, p.148.
[61] NERA (November 2019), 'Cost of Capital for SPT in RIIO-T2', Appendix B
[62] Oxera (2020), The cost of equity for RIIO-2 – Q3 2020 update, section 3.4
[63] NERA (November 2019), 'Cost of Capital for SPT', section 3.1.2.

3.35 Both consultants adopt a debt beta of 0.05 in their empirical beta analysis. This figure is sufficiently lower than Ofgem's 0.125 debt beta assumption, which they have retained from the SSMD citing the evidence presented in that document, and a UKRN study prepared by CEPA.[64] Oxera has addressed CEPA's report to the UKRN in their recent report[65]. Oxera demonstrates that methods based on regressions (the direct and indirect methods) and structural models have the advantage of measuring the systematic exposure of debt to market risk and should be used when setting the debt beta. In contrast, the spread decomposition method lacks robust theoretical support and depends on multiple uncertain parameters. The degree of uncertainty over the assumptions required by the spread decomposition approach suggest that it provides little or no incremental evidential value relative to the other approaches. Oxera finds that a debt beta assumption of 0.05 for regulated industries would be appropriate based on the estimates from the direct and indirect regressions, along with the corrected version of CEPA's structural method.[66]

3.36 The CMA determined a debt beta of 0.05 in its recent provisional findings for the NERL redetermination in contrast to the CAA's estimate of 0.1[67]. The CMA found that there was significant uncertainty over the ability to measure debt betas using the CAA's decomposition approach. As mentioned in our Business Plan[68], the beta risk borne by debtholders will be related to the business risk of the sector – the debt beta is likely to be higher the greater the systematic risk present in the sector. The debt beta for the energy sector should therefore be no higher than that for NERL.

3.37 NERA and Oxera arrive at an asset beta range of 0.38-0.40 and 0.38-0.41 respectively,[69,70] assuming a debt beta of 0.05 – higher than that set by Ofgem in the Draft Determination[71]. Both consultants' lower bounds are based on beta estimates derived from NG. This represents a reasonable lower bound given that NG's asset beta will also reflect the risk associated with its lower risk US network operations[72]. The upper bound estimates for both consultants have been informed by the empirical evidence on European energy comparators asset betas.

Step 2: Cross-checks

3.38 In Step 2 of arriving at the baseline cost of equity allowance in the Draft Determination, Ofgem cross-checks the CAPM-implied Cost of Equity results against those produced by alternative forward-looking approaches to assess whether the CAPM is appropriately capturing the return required by equity investors. Ofgem has chosen to revise downwards the allowed cost of equity estimate from 4.3% to 4.2% (real-CPIH) based on updated evidence from the following cross-check evidence sources of: Market-to-Asset Ratios (MARs), OFTO returns, investment managers' forecasts, infrastructure funds, as well as the new MM WACC cross-check.

3.39 Ofgem places undue weight on comparators that are not analogous to the TOs, e.g. water (and in some cases very different e.g. OFTOs and infrastructure funds) because these enable Ofgem to argue for a lower Cost of equity whilst placing inadequate weight on comparators that are more appropriate because these point to a high Cost of Equity.

3.40 The cross-checks utilised by Ofgem are unreliable evidence sources on forward-looking equity market returns and their use as cross-checks for the CAPM-implied cost of equity is in error. This is confirmed by the analysis by independent experts, Oxera and NERA. Specifically, infrastructure funds and OFTO bids have different risk profiles than those of UK energy firms, with OFTOs IRR also being unverified. OFTOs are very different to TOs in terms of their tasks and their regulatory obligations. CEPA fails to take into account all

[64] CEPA (December 2019), Considerations for UK regulators setting the value of debt beta
[65] Oxera (June 2020), 'Estimating debt beta for regulated utilities'
[66] Oxera (June 2020), 'Estimating debt beta for regulated utilities', figure 1.
[67] CMA (March 2020), NATS provisional findings, para.12.114-115, p.160.
[68] SPT RIIO-2 Business Plan – Finance annex p. 13
[69] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 3.7
[70] Oxera (September 2020), 'The cost of equity for RIIO-2 – Q3 2020 update', section 3.3
[71] For comparison purposes NERA's range is 0.35-0.37 compared to Ofgem's 0.26 to 0.34 when set on zero debt beta basis.
[72] NG plc's asset beta is likely an underestimate of the true asset beta of NG plc's UK regulated business as its composite beta reflects the combined systematic risk faced by both its UK and US operations. NG plc's US operations are subject to regulatory regimes which impose lower risks on investors compared to that of RIIO-T2. NERA's decomposition analysis supports higher asset beta values for NG's GB network relative to NG's group asset beta, with an estimate of at least 0.45.

relevant adjustments that affect estimation of MARs, with no evidence to conclude that MARs for regulated utility companies are above 1. The observed MARs can be explained without appealing to investors being overcompensated for risk. The investment manager evidence appears to support a higher TMR once obvious outliers are discarded. See our response to FQ8 for more detail.

3.41 Finally, when examining Ofgem's MM cross-check, we note when adjusting for errors in the methodology and applying the recommended CAPM parameters from Oxera and NERA, the MM violation is not seen. Please see our response to FQ7.

3.42 Indeed, it can be shown that once using updated data or correcting for outliers/errors, Ofgem's cross-checks actually support a higher cost of equity than that found in the Draft Determinations.

3.43 An appropriate and valid cross-check to the CAPM-implied Cost of Equity is Oxera's ARP-DRP differential cross-check. Updating their analysis[73], Oxera benchmark Ofgem's implied ARP−DRP differential against contemporaneous market evidence i.e. traded yields of energy bonds over the six-month period preceding the RIIO-2 DD. Oxera find that the ARP−DRP differential implied by Ofgem's RIIO-2 DD mid-point Cost of Equity allowance falls significantly below the 15th percentile of the empirical distribution of market evidence from the last six months – this is before accounting for Ofgem's proposed Outperformance wedge adjustment which would lower the ARP-DRP differential further down in the distribution.[74] It is also lower than that seen from previous regulatory allowances for energy companies.

3.44 The ARP-DRP differential test shows that Ofgem's Cost of Equity allowance falls far below in the empirical distribution and therefore needs to be corrected in order to bring it in line with that implied by recent market evidence. Adopting a Cost of Equity implied by NERA and Oxera's recommended ranges would achieve this. See our response to FQ8 for more detail.

Step 3: Outperformance Wedge

3.45 In its final step for setting the allowed Cost of Equity for the RIIO-2 price control, Ofgem applies a downwards Allowed vs Expected Return adjustment, or 'Outperformance Wedge', to the allowed Cost of Equity to reflect their unprecedented assertion that investors' expect network companies to outperform the cost and output targets set at the price control, which supplements the base return.

3.46 We not only disagree with Ofgem's expected outperformance figure of 0.25% at 60% notional gearing, we fundamentally disagree with the concept of the outperformance wedge altogether and believe that in the context of the risks prevalent in today's economy with the potential longer-term economic disruption due to COVID-19, it should be scrapped altogether.

3.47 It is our belief that Ofgem's proposed adjustment to baseline returns is arbitrary and is a policy that has been based on a flawed conceptual and evidential basis. The adoption of such an adjustment is unprecedented by any other regulator within a price control settlement and would have negative implications on companies' delivery incentives and financeability. It will damage investor's confidence in the sector and weaken incentives, ultimately leading to poor consumer outcomes.

[73] Oxera (September 2020), 'Asset risk premium relative to debt risk premium', prepared for the ENA
[74] Oxera (September 2020), 'Asset risk premium relative to debt risk premium', prepared for the ENA, section 4

Cost of Debt

3.48 In the Draft Determination, Ofgem has proposed to index the allowed Cost of Debt based on the iBoxx 10+ years Utilities index, instead of the current RIIO-1 approach of indexing the allowance on the average yields of the two A and BBB 10+ iBoxx non-financial corporate indices. Ofgem indicates that, if this index is used, it is minded not to apply a 'halo' adjustment, as this index better reflects energy networks' actual Cost of Debt,[75] and as such will allow a 17bps above the index to allow for additional borrowing costs. Ofgem's rationale for adopting the iBoxx Utilities as the reference benchmark relies on its assessment that companies' debt financing costs more closely match the iBoxx Utilities index than the iBoxx A/BBB, as employed by Ofgem at RIIO-1.

<u>Use of the iBoxx utilities index</u>

3.49 Ofgem has proposed a Cost of Debt model which is untested and which could introduce further unknown risks during a time of heightened financial uncertainty. Compared to the iBoxx A/BBB index, the iBoxx Utilities is sector specific and does not have a defined rating (other than investment grade), whereas iBoxx A or BBB indices are regularly updated to include only A or BBB bonds respectively. By adopting this index, companies are exposed to a risk of under-recovery of Cost of Debt if the Utilities index credit rating improves over RIIO-2 (i.e. the Cost of Debt allowance declines) due to the fact it does not have a defined rating.

3.50 Ofgem should take this additional risk into consideration within its calibration of the Cost of Debt mechanism if the Utilities Index is confirmed as the benchmark index.

<u>Calibration of the Cost of Debt mechanism</u>

3.51 Regarding the optimal trailing average for the benchmark index, the length should match the average tenor at issuance of network companies' debt. In their updated analysis, NERA shows that energy network bonds have an average tenor of issuance of around 19 years, with the average tenor from both the water and aviation sector, where the regulatory rules have not provided incentives to issue shorter 10-year debt instruments, of around 25 years for water companies and 20 years, respectively. NERA also finds that the starting 10-year trailing average would exclude almost half of the sector current outstanding debt if implemented, whereas a 15-year trailing average would provide coverage for 80% of companies' historical debt issuance.[76]

3.52 The market evidence on the efficient tenor at issuance in energy and other regulated sectors supports a trailing average of at least 15 years, the (approximate) shortest tenor observed for any regulated sector.

3.53 The move to a longer trailing average is also supported when observing NERA's expected debt performance modelling for RIIO-2. NERA show in their modelling that Ofgem's own analysis – which shows network companies recovering costs with a margin of 12 bps in its central scenario – would decline by 36 bps (i.e. 53 bps less 17 bps) to negative 24 bps under NERA's revised additional cost of borrowing estimate.[77] This underperformance is seen across varying interest rate scenarios.

<u>Halo effect and additional costs of borrowing</u>

3.54 Ofgem argues that when using the Utilities index, there is no need to adjust for halo effect or new issue premium (NIP). NERA has modified its approach to calculating the NIP to respond to Ofgem's comments on its earlier report, and calculating spreads based on duration matching find a negative halo of between -4 and

[75] Ofgem (2020) Consultation - RIIO-2 Draft Determinations – Finance Annex, p. 13.
[76] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 6.3
[77] NERA (September 2020), 'Cost of Debt at RIIO-2 - a report for Gas Distribution Networks and Transmission Network Operators' prepared for the ENA, section 2

-14bps when using the iBoxx Utilities Index (compared to Ofgem's +11 and +4 Halo, respectively)[78]. The result is consistent with empirical studies.[79] Networks companies' additional cost of borrowing should include an NIP of around 10 bps to compensate for companies' Cost of Debt issuances.

3.55 Based on updated evidence, NERA estimates additional cost of borrowing of 53 bps, with a range of 47 to 59 bps, compared to Ofgem's DD of 17 bps.[80]

Deflationary approach

3.56 Additionally, when deriving the real debt allowance, Ofgem recommends using an expected value for CPIH directly to deflate iBoxx Utility nominal yields. Ofgem's preference is to use the Office for Budget Responsibility's (OBR's) longest-term CPI forecast as a proxy for expected CPIH. We consider instead the use of outturn inflation as a viable alternative for determining the real allowed Cost of Debt. The approach has the advantage of largely mitigating risk for investors in recovering their nominal debt cost: the inflation element of the Cost of Debt is recovered as a capital gain on the RAV, and the remaining real element is recovered as a return on the RAV. The approach also avoids forecasting errors.

3.57 Please see our responses to FQ1-3 for further detail.

Financeability, notional gearing & RoRE

3.58 Ofgem has conducted an "in the round" assessment of financeability for the RIIO-2 period with the focus very much on the debt finance of a notional company and very little regard to actual company parameters or the financeability of equity. This is at odds with the analysis that companies were instructed[81] to provide along with their Business plan submissions[82].

3.59 We welcome Ofgem's view on the target ratios that companies should obtain at least two notches above investment grade as this indicates that, in principle, Ofgem is seeking to maintain the credit quality of the sector as a whole. This benefits consumers through lower bills via interest costs, while maintaining the regulatory precedent of providing the industry with the required headroom, ultimately resulting in greater financial resilience for critical national infrastructure.

3.60 However, while an "in the round" assessment has merit, the impact on individual ratios and importance placed on them by external parties such as investors and credit ratings agencies should not be ignored, such as the adjusted interest cover ratio (AICR) which is a key indicator of a company's ability to pay upkeep on its debts.

3.61 It is critical that Ofgem does not lose sight of the financeability of the actual companies during the RIIO-2 period and the impacts that the parameters Ofgem have set will have on the ability of those companies to aid in the green recovery as well as the path to a Net Zero economy.

3.62 Ofgem needs to reflect, the potential scale of expenditure that may be required via reopeners, through its stress testing of financeability. The output from financeability stress testing needs to demonstrate the company can maintain a comfortable investment grade rating, after funding all reopeners, to continuously comply with its licence and facilitate the raising of additional funds as required. Given the "scale" of investment that may be required to be funded via reopeners the RIIO-2 process needs to include these

[78] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 6.4
[79] Maitra and Salt (May 2018) New issuance premium in European corporate bonds, Lombard Odier Asset Management; Rischen and Theissen (2018), Underpricing in the euro area corporate bond market: New evidence from post-crisis regulation and quantitative easing, CFR Working Paper, No. 18-03, University of Cologne, Centre for Financial Research; Adams and Smith (2019), "Fixed Income Analysis", John Wiley & Sons, p. 839, Leake (2003), Credit spreads on sterling corporate bonds and the term structure of UK interest rates
[80] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 6.5
[81] RIIO-T2 Business Plan Guidance 9 September 2019 https://www.ofgem.gov.uk/system/files/docs/2019/10/riio-2_business_plans_guidance_september_2019.pdf
[82] SP Energy Networks RIIO-T2 Business Plan 2021-2026 page 189

forecasts in the annual live forecasting proposals. Inclusion of reopeners in the new "live" forecasting AIP process will be essential to reduce the burden on companies as true-ups will be actioned faster.

3.63 We encourage Ofgem to include a step in its process to test if the "notional company" is realistic and whether their assumptions exhibits a level of prudence, that should be expected from an objective economic regulator. **The increase in the assumption of CPIH index linked debt from 25% to 30% should be re-assessed. A comparison of the notional company's financial ratios to those of actual companies should be given significant weight in assessing the achievement of quantitative measures of investment grade.**

3.64 Adjustments to assumptions around the financial structures of the notional company significantly improve the implied credit ratios but may not reflect the real-world characteristics of companies. It is also important that Ofgem's "in the round" assessment of financeability is made in the context of the wider Draft Determination, which in sum consists of a series of poorly justified, short sighted decisions which makes the overall package unacceptable to any rational investor and not in the interests of customers.

3.65 Furthermore, Ofgem has indicated that they have reduced the financial risks that companies face in the RIIO-2 period with the move to further Indexation (e.g. for both Cost of Debt & cost of equity) and reduction in the Totex Incentive Mechanism (TIM). However, this does not offset the additional risks that the potential investment requirements of reopeners during the RIIO-2 period will add. Inclusion of new mechanisms that deviate from established regulatory precedent, such as the Expected Versus Allowed adjustments, only add further uncertainty at a time when falling returns hamper the industry's ability to support and further the delivery of the UK's Net Zero ambitions.

3.66 As investors have recognised, Ofgem is "stuck in austerity" mode.[83] The current Draft Determination proposals are not compatible with the significant investments required to achieve the proposed level of decarbonisation in what is a short space of time. It also poses a more general risk to continued investment in the UK at this critical time. Further, the package as a whole provides little incentive for innovation and creates a greater level of uncertainty due to the move away from ex ante allowances. This does not reflect the level of risk currently mirrored by the proposed WACC values.

3.67 The long-term effects of the COVID-19 pandemic on the wider economy, notably on inflation, can also not be ignored. These factors must be reviewed due to the cashflow risk involved and the impact this could have on UK regulated energy network companies. A "Cash flow gap" arises due to nominal interest debt raised by networks being paid down by a real return with the Inflation proportion added to RAV and paid over time. This means that network companies in the UK are vulnerable to prolonged periods of low inflation. This could lead to a relative reduction in cash flow and a weakening of a network's financial profile, which is a credit negative.

3.68 Additionally, Ofgem's view on comparability across sectors is misguided. The proposal to set WACC at the same level across Gas and Electricity is not consistent with Ofgem's own reasoning for providing a lower level of gearing for electricity to take account of the higher level of risk involved with the delivery of the required Totex in the regulatory period and, as such, is demonstrably irrational. This approach uses notional gearing as a financeability lever and not as an independent cross check on the suitability of the proposed industry WACC. This also represents a clear derivation from established precedent in RIIO-1. Ofgem explicitly adopted a higher cost of equity in RIIO-1 for electricity transmission companies to reflect the scale and complexity of the capital investment programme. Given that the investment requirements across RIIO-1 and RIIO-2 are comparable the change in assumption is therefore inconsistent, unjustified and will negatively impact the attractiveness of the GB regulated energy sector.

3.69 Alignment of cost of capital with the water sector is also incorrect due to the differing levels of risk involved in both sectors which has been observed in price control periods. The higher risk of electricity has been an established factor in previous electricity price controls due to the fact that the nature of projects undertaken in electricity, particularly transmission, involves significantly higher risk than those in the water sector. If anything, it could be argued that the level of disparity has only increased due to the criticality of the

83 Deepa Venkateswaran (Bernstein) (2020), "An Open letter to the CEO of Ofgem: With great power comes great responsibility ..."

electricity networks in the transition to net zero which may necessitate far higher levels of investment than set out in the baseline Draft Determinations.

3.70 There is a lack of fairness in the proposed common incentives packages on offer across the industries as the proposals for gas companies are materially higher than those in electricity (0.44 vs 0.22 Return on Regulatory Equity (RORE) bps on average). Furthermore, the expected RORE ranges for the electricity transmission operators are significantly lower than that of the listed UK water networks companies with the water companies on average, able to achieve a RORE in the range of 7.2% - 0.2%[84] and transmission operators only able to achieve a range between 4.5% - 1.8% RORE[85], a much lower and narrower RORE window.

3.71 Therefore, the level of risk that the electricity transmission companies will be exposed to during RIIO-2 and the level of proposed returns are not consistent when compared with regulated companies in the water and gas sectors. Consequently, the package as a whole cannot be deemed to be financeable on an equity basis.

Financial policy and modelling

3.72 Ofgem has provided analysis of the Draft Determination decisions via the publication of the Draft Determination annexes themselves as well as the licence financial model that support the main documents. We have had issues reconciling data across these sections which has been communicated to Ofgem through a ‘SPT T2 Draft Determination – tracker’. This tracker lists 15 issues of which 9 have been resolved through the draft determination response period. This has had the impact of condensing the productive draft determination response period to fully evaluate Ofgem’s proposals, with this further complicated by the errors identified within the cost assessment process undertaken by Ofgem.

3.73 Ofgem has sought to evolve the current RIIO-1 approach but further information and an impact assessment will be required for all impacted parties including Suppliers and Generators to understand the impact and potential greater volatility in TO revenues. For SPT it is not clear, in some areas, how these processes will work in practice.

3.74 For example, the proposal to move from Final Proposal Revenues and Mod terms to “Live Revenues” is welcome, but the wider cash flow impact on the wider energy markets must be considered due to the volatility this will create in terms of suppliers charging timelines.

3.75 The close-out of RIIO-T1 and the treatment of legacy items must also be managed to ensure that the transition to annual revenue recalculation does not have a material impact on both the network companies and wider consumer bills. Again, Ofgem has signalled its willingness to deviate from regulatory precedent by changing its long-established views on price control mechanisms such as using WACC to adjust for the Time Value of Money (TVM). Given the scale of movement from ex ante funding to that of a mix of up front funding and reopeners, it is imperative that Ofgem ensure the price control process does not get burdened by unnecessary impediments such as lengthy regulatory processes which delay funding decisions and allows the companies the ability to deliver investment where required to achieve a network that is a catalysts to a low carbon economy.

3.76 In parallel to the Draft Determination process, the licence drafting for RIIO-2 is ongoing. However, until further clarity and analysis has been provided on the various price control instruments, such as the Licence, Financial Handbook and Price Control Financial Model (PCFM), a full understanding of the wider impacts cannot be achieved.

[84] (Bernstein) (2020), “An Open letter to the CEO of Ofgem: With great power comes great responsibility ...”
[85] Source Ofgem daft determination finance annex p91

Responses to Consultation Questions - Finance

FQ1. Do you agree with our approach to estimating efficient debt costs and setting allowances for debt costs?

Calibration of the Cost of Debt index

3.77 When calibrating the proposed index, Ofgem has proposed to calculate the allowance using an extending 10 to 14-year trailing average plus a 17bps additional cost of borrowing allowance based on its modelling that suggested this calibration would allow the sector to recover debt costs over RIIO-2.

3.78 When determining the optimal trailing average for the benchmark index, the length should match the average tenor at issuance of network companies' debt. By doing so, an energy network that issues a bond in line with the average tenor will receive an allowance equal to the efficient cost of the bond in each year of the lifetime of the bond, thus ensuring a reasonable likelihood of servicing its debt costs. In their updated analysis, NERA show that energy network bonds have an average tenor of issuance of around 19 years. The efficient tenor should be informed by evidence from other regulated sectors given the potential impact that the RIIO-1 regulatory framework has had on companies' debt issuances. There may be a risk that energy networks in RIIO-1 have sought to match the 10-year trailing average of the index determined by Ofgem at RIIO-T1/GD1. The length was set due to the availability of the relevant iBoxx indices at the time (1998-99)[86], which placed a limit on the trailing average length.[87] There is a risk that this trailing average length has encouraged network companies to issue shorter debt tenors relative to the efficient tenor. NERA have examined updated evidence from both the water and aviation sector[88], where the regulatory rules present in the most recent controls for these sectors have not incentivised shorter debt issuances due to the respective regulators' decision to not to index their Cost of Debt allowances to any benchmark. NERA show that the average tenor at issuance is around 25 years for water companies and 20 years for London Heathrow Airport (LHR).

3.79 The profile of sector debt issuance should also inform the length of trailing index. NERA find that the starting 10-year trailing average would exclude almost half of the sector current outstanding debt if implemented, whereas a 15-year trailing average would provide coverage for 80% of network companies' historical debt issuances.[89]

3.80 Ofgem's DD trailing average proposal of 10-14yr will further encourage companies to shorten tenors of new issuance in order to match and outperform the index, thus leading to increased refinancing risks for energy networks in RIIO-2 and beyond. The market evidence on the efficient tenor at issuance in energy and other regulated sectors supports a trailing average of at least 15 years, the (approximate) shortest tenor observed for any regulated sector.

3.81 The move to a longer trailing average is also supported when looking at NERA's modelling of expected RIIO-2 debt performance. Looking at Ofgem's own debt analysis for RIIO 2 in the DD – using NERA's debt models – which shows that TOs and GDNs would recover debt costs with a margin of 12 bps in its central scenario, would decline by 36 bps (i.e. 53 bps less 17 bps) to negative 24 bps under NERA's revised additional cost of borrowing estimate of 53 bps (see below more detail on NERA's estimate).[90] NERA show that Ofgem's current proposed index, with NERA's revised additional cost of borrowing estimate, would expose network companies to underperformance risk under various interest rate scenarios. The calibration of the index to a longer trailer average length would minimise the risk of companies underperforming against the debt allowance, allowing them to sufficiently service their incurred debt costs.

[86] The iBoxx GBP Benchmark Index was published on 1997/12/31, and the yield on the index start on 1998/1/1. See IHS Markit iBoxx GBP benchmark documentation, p.18.
[87] In addition, for GDNs, a substantive element of industry debt was issued post distribution network (DN) sales in 2005, and therefore the then 10Y trailing average captured the period of debt GDN debt issuance.
[88] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 6.2
[89] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 6.3
[90] NERA (September 2020), 'Cost of Debt at RIIO-2 - a report for Gas Distribution Networks and Transmission Network Operators' prepared for the ENA, section 2

3.82 Based on the above, we recommend that that the Cost of Debt indexation should be based on a starting trailing average of **a minimum of 15 years**.

3.83 Additionally, we believe in a simple average approach to calibrating the Cost of Debt mechanism, as setting this based on a weighted average would be akin to a pass-through for the largest network in the sector and would fail to treat the other companies' actual debt costs.

Halo effect

3.84 Ofgem argues that when using the Utilities index there is no need to adjust for halo effect or new issue premium (NIP), based on their analysis which estimated a halo of only 4bps.[91] Ofgem has made the error of retaining its halo estimation approach used in the SSMD, which NERA have set out their report for the ENA[92], does not control for tenor correctly, and therefore is not a reliable measure of network bonds' performance. Responding to Ofgem's comments that NERA's approach does not match duration[93], NERA has amended its approach slightly to calculate spreads based on duration matching, where duration is defined as the weighted average of the times that cash-flows are received.[94] NERA estimates a negative halo of -4 bps based iBoxx A/BBB spread less company bond spread (compared to Ofgem's +11 bps), and -14 bps when we use iBoxx Utilities (compared to Ofgem's +4 bps), respectively. [95]

3.85 The negative halo estimated is not surprising, as it reflects the cost of incentivising investors in the primary market relative to the secondary traded market yields, and NERA's estimate is consistent with recent empirical studies.[96] Based on NERA's analysis, Ofgem's additional cost of borrowing allowance for networks should include an NIP of around 10bps to compensate for companies' Cost of Debt issuances.

Additional borrowing costs

3.86 In its analysis of additional borrowing costs, Ofgem has estimated transaction costs and liquidity costs broadly in line with NERA's estimates. However, Ofgem has not provided a sufficient cost of carry allowance and have not provided for CPI indexation cost as well as the above-mentioned NIP costs. NERA has provided updated estimates for the ENA in response to Ofgem's comments.[97]

3.87 Ofgem's analysis of cost of carry is flawed, leading to an understatement of networks' cash positions. Firstly, Ofgem's analysis does not reflect divergent approaches taken by companies to location of Treasury functions. For some networks, the Treasury functions are undertaken entirely at either ultimate parent company or the midCo group level, whereas other networks have all Treasury functions conducted at the OpCo level. Thus, Ofgem's estimated median of 0.6% based on OpCo understates the actual cash holdings, since some networks do not operate Treasury at the OpCo level. Also, Ofgem's 75:25 respective weights on the OpCo and Group level cash appears to be arbitrary, and it is unclear whether Ofgem has considered midCo or parent. Secondly, Ofgem only relies on end-year snap-shot in the RFPR/BPBT where cash-positions are managed down, whereas the networks' within-year average cash holdings are substantively higher. Lastly, Ofgem appears to have solely relied on RIIO-1 average cash holding in its analysis, but companies cash requirements vary substantively depending on refinancing, and RIIO-1 data may not be representative of RIIO-2 for many networks.

[91] Ofgem (July 2020) Consultation – RIIO-2 Draft Determination – Finance Annex, p. 179
[92] NERA (September 2020) Review of Ofgem's DD Additional costs of borrowing, and deflating nominal iBoxx
[93] In regards to NERA' calculation of spread, Ofgem claim that the BoE nominal spot curve is a zero coupon curve, whereas the bonds issues by companies are not zero coupon, and therefore there is a duration mismatch in our calculation of the relative spread. See: [ref]
[94] Using the standard Macaulay duration as follows: $Macaulay\ Duration = \sum_{t=0}^{n} \frac{PV(CF_t)\times t}{Bond\ Price}$. Zero coupon bonds have a duration equal to their tenor, as the investor must wait to maturity to receive the value of the bond.
[95] NERA's sample includes all outstanding energy network bonds, including those of short tenor as we account for tenor precisely through duration matching. They have excluded from their analysis the most recent five bonds issued during COVID-19 crisis given high levels of market volatility
[96] Maitra and Salt (May 2018) New issuance premium in European corporate bonds, Lombard Odier Asset Management; Rischen and Theissen (2018), Underpricing in the euro area corporate bond market: New evidence from post-crisis regulation and quantitative easing, CFR Working Paper, No. 18-03, University of Cologne, Centre for Financial Research; Adams and Smith (2019), "Fixed Income Analysis", John Wiley & Sons, p. 839, Leake (2003), Credit spreads on sterling corporate bonds and the term structure of UK interest rates,
[97] NERA (September 2020), 'Review of Ofgem's DD Additional costs of borrowing, and deflating nominal iBoxx'

3.88 In addition, Ofgem argues that NERA has double-counted and overestimated the cost of carry, by assuming 12-24 months' cash is held and revolving credit facilities sized at 10% of the debt book. NERA shows that if assuming that on average half of the pre-financing requirement will be met by using liquidity facilities, they estimate a cost-of-carry range from 11-23bps.[98]

3.89 Ofgem has argued in the DD that the impact of the inflation wedge means if liability remains in RPI (rather than swapped to CPIH), it will improve cash flow metrics in near term. The premium for CPI swaps compared to RPI swaps is limited to 'low single digit basis points', which, when applied to 25% of the portfolio, may indicate 1-2bps.[99] Ofgem concludes that the CPI indexation associated costs should not be remunerated in the Cost of Debt allowance, as not required for notional company. In addition, Ofgem assumes 30% of the networks' debt to be CPIH-linked, which is an increase from SSMD working assumption of 25%.[100]

3.90 Ofgem has however ignored the basis risk in asserting companies do not need to be compensated for the switch from RPI to CPIH. The existing framework for indexing the RAV with outturn RPI provides a natural hedge for companies financed with RPI index linked-debt, where both the allowed return and actual Cost of Debt grow in line with outturn RPI inflation, leaving equity returns unchanged. This natural link will be broken under the CPI indexation, since ex-post variation in the outturn RPI-CPI wedge exposes companies to additional risks. This risk exists even if investors are compensated for expected difference between RPI and CPI inflation ex-ante.

3.91 The additional cost of index-linked debt due to the deviation of the outturn RPI – CPI wedge remain unfunded under the CPI indexation approach. NERA illustrates that the mis-match between RPI ILD and CPI(H) linked RAV creates basis risk, and the networks will need to consider issuing CPI(H) ILD. NERA has reviewed updated market evidence on Oersted's nominal and CPI-linked bonds, which supports a CPI premium of between 30 and 100 bps, which supports NERA's original estimate of 50 bps.[101] Assuming 30% ILD for the notional company, supports an additional cost of 15 bps (i.e 50 bps*30%).

3.92 Taking the additional costs of borrowing together, based on updated evidence, NERA[102] concludes that Ofgem should provide an additional cost of borrowing allowance in the range of 47 to 59 bps, compared to their DD allowance of only 17 bps.

<u>Deflationary approach</u>

3.93 Additionally, when deriving the real debt allowance, Ofgem recommends using an expected value for CPIH directly to deflate iBoxx Utility nominal yields. Ofgem's preference is to use the OBR longest-term CPI forecast as a proxy for expected CPIH. We consider that the use of outturn inflation, as used to index the asset base, is a viable alternative for determining the real allowed Cost of Debt. The approach has the advantage of largely mitigating risk for investors in recovering their nominal debt cost: the inflation element of the Cost of Debt is recovered as a capital gain on the RAV, and the remaining real element is recovered as a return on the RAV. The approach also avoids forecasting errors, which could occur with Ofgem's proposed approach as the OBR forecast (effectively 2%) means that investors may not recover their costs in any one year or indeed regulatory period. Although it does risk introducing volatility in the allowed real debt component of revenues, this could be managed e.g. by setting the allowance based on an expected value for inflation and then truing-up for outturn inflation over a number of years.

[98] Assuming pre-financing period to be between 12 to 24 months in line with licence requirement and rating criteria debt tenor to be 15 years (refinancing 1/15 of debt each year) consistent with Ofgem's assumption in DD Net carry cost of iBoxx less overnight LIBOR on cash-deposits.
[99] Ofgem (July 2020) Consultation – RIIO-2 Draft Determination – Finance Annex, Annex 2, pp, 183-184
[100] Ofgem (July 2020) Consultation – RIIO-2 Draft Determination – Finance Annex, Annex 2, p. 99
[101] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 6.5.2
[102] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 6.5

FQ2. Do you agree with our proposal to use the iBoxx GBP Utilities 10yr+ index rather than a combination of iBoxx GBP A and BBB 10yr + non-financial indices?

3.94 The use of the iBoxx Utilities 10yr+ index as the benchmark index for the Cost of Debt mechanism could expose network companies to rating risk over the RIIO-2 period. The iBoxx Utilities Index is sector specific, in that it only includes utility sector bonds, and does not have a defined rating (other than investment grade), whereas the iBoxx A and BBB indices are regularly updated to include only A or BBB bonds respectively. The iBoxx Utilities index has a current rating of A/BBB, whereas before 2011 it had a rating of A. The proportion of BBB-rated bonds included in the iBoxx Utilities index was around 10-30% during 2000-2012, but this ratio has increased to 60% by 2018. The decline in the rating of the index has been a result of the deteriorating credit quality of the regulated sectors.

3.95 By adopting this index, companies are exposed to an additional risk of under-recovery of the Cost of Debt due to the lack of a defined rating for the index. Ofgem set the revenue allowance for the notional company with ratios consistent with Baa1 (at best)[103], however if the iBoxx Utilities strengthens over RIIO-2, then it will amplify the mismatch between the rating for the notional company (i.e. Baa1) and the new Cost of Debt allowance. NERA estimate in their report for the ENA that if the iBoxx Utilities would align with a single A rating (Moody's A2), as it was prior to 2010, then the Cost of Debt allowance based on the iBoxx Utilities index would be another 1.5 notches higher than expected at review (i.e. under-funding by 1.5 notches relative to A/BBB, or A3/Baa1). This would result in under-funding of 15 bps relative to Ofgem's assumed performance.[104]

3.96 The Utilities index is comprised of a significant proportion of bond issues from both the water sector and European based utility groups that have implicit state guarantees. Ratings changes in either of these two groups will significantly influence the future direction of the index, exposing RIIO-2 companies to under-recovery of the allowance. Ofgem should take this additional risk into consideration within its calibration of the Cost of Debt mechanism if the Utilities Index is confirmed as the benchmark index.

FQ3. Do you agree with our proposal that the RAV growth profile of SHET continues to be materially different to other networks and therefore warrants continuation of a bespoke RAV weighted allowance calculation?

3.97 We believe it is for each company to propose the relevant mechanism which supports their business model. Therefore, we do not have a view on this.

FQ4. Do you have any views on the model to implement equity indexation, as published alongside this document, (the "WACC allowance model.xlsx") or on the annual update process?

3.98 In the WACC allowance model, Ofgem has proposed to use a one-month averaging period to set the RFR rather than a longer 6-or 12-month period, noting that this will ensure the cost of equity allowance more quickly reflects changes in market rates. As part of the Annual Iteration Process, Ofgem proposes to update the model in order to address the uncertainty caused by a potential change to the definition of the RPI[105] - as the required adjustment to ILGs (which are deflated by RPI) to derive a measure deflated by CPI will be uncertain over RIIO-2 if the definition of RPI is altered.

3.99 We disagree with Ofgem's use of a one-month averaging period to set the RFR. Basing the RFR on such a particular narrow point in time raises risk that if the allowed cost of equity for the following year will be below the true market cost of equity for that year. This risk is heightened with the current volatility in capital markets. We recommend a longer averaging period in order to smooth out spot market volatility over RIIO-2.

3.100 We retain our view that the appropriate estimation for the real RFR under a CPIH-based price is to set the parameter based on yields on 20-year nominal UK gilts and deflated by expected CPIH inflation, as this

103 Ofgem has stated that the notional package will ensure outturn ratios to be "two notches above investment grade" See: Ofgem (July 2020), RIIO-2 Draft Determinations – Finance Annex, page 96, para 5.10
104 NERA (September 2020), 'Review of Ofgem's DD Additional costs of borrowing, and deflating nominal iBoxx'
105 Ofgem (July 2020), 'Consultation - RIIO-2 Draft Determinations – Finance Annex', p. 33

would provide a more objective and stable measure of the real RFR, and thus the Cost of Equity index, compared to Ofgem's approach as ILGs. ILGs with long maturities may provide a distorted measure of the RFR because of regulatory requirements on institutional investors to hold index-linked debt, such as pension funds, which creates an artificially inelastic (or excess) demand for these assets. Yields on ILGs have also been found to be volatile over time. This volatility has been heightened recently by the impacts from Brexit and COVID-19. Nominal gilts do not have these issues and thus provide a more objective and stable measure of the RFR relative to ILGs. The use of nominal gilts less expected CPI inflation would also avoid the need for Ofgem to adapt its approach during RIIO-2 for changes arising from the Government's consultation on changes to RPI. Also, they are widely used by financial practitioners and by UK and European energy regulators.

3.101 Using the above approach and updating for current market evidence (cut-off date of 21 July 2020), NERA estimate that the average RFR would be -1.18% (real-CPIH) for RIIO-T2, which is higher than the -1.48% estimated using Ofgem's Draft Determination cut-off date of 11 May 2020.

3.102 There is the continual debate around whether nominal gilts or ILGs alone provide a perfect measure of the 'true' RFR, with the arguments around relying on either measure centre around the inflation risk premium embedded within nominal gilts and the liquidity premium and market distortions that impact on ILG yields. We acknowledge that there is a high degree of uncertainty when trying to quantify these factors that impact both RFR measures. We consider that an alternative approach to estimating the RFR can be found from Oxera's exploration into CMA's concerns of the positive relationship between the WACC and gearing in their Provisional Findings in the NERL redetermination.

3.103 Oxera has identified that the current RFR estimation approach of using spot yields on ILGs leads to an under-estimate of the RFR in the CAPM framework. The issue was brought to the ENA's attention from the CMA's concerns in the Provisional Findings for the NERL redetermination around the consequences of the standard regulatory approach to 're-gearing', which resulted in a positive relationship between the WACC and gearing. The CMA state that this runs counter to the MM theorems that the cost of capital is invariant with respect to the level of gearing.

3.104 In their submission to the CMA in the PR19 appeals, the ENA provided a recent report by Oxera[106] where they find that the main cause of the upward relationship is due to the RFR being set too low, resulting in an underestimate of the cost of equity at all gearing levels. The incorrect estimate of the RFR used in the CAPM was revealed by the CMA and UK regulators following the UKRN's recommendations to regulators to set the RFR estimate based on spot (zero coupon) yields on ILGs, at their chosen horizon, given their negligible default risk. This regulatory issue had not presented itself prior to the CMA's consideration as it has been common in previous regulatory reviews to set regulatory allowances on the RFR above the spot rates on gilt yields (i.e. based on long-term averages).

3.105 In reviewing the academic literature, Oxera find that that spot yields on government bonds cannot always be used as a proxy for the RFR in the CAPM framework. Oxera provide the following two reasons as to why spot yields on ILGs require an adjustment in order to be used as a proxy for the RFR in the CAPM:

i. **A substantial convenience premium for government bonds.** Empirical studies show that government bonds possess special safety and liquidity characteristics compared to other securities. This pushes the yields on government bonds below the required rate of return for a zero-beta asset. Therefore, to be used as a proxy for the RFR, the yields on bonds issued by governments with a high sovereign credit rating would need to be adjusted upwards to remove the impact of the convenience premium. Krishnamurthy and Vissing-Jorgensen (2012) write:[107]
Treasury interest rates are not an appropriate benchmark for "riskless" rates. **Cost of capital computations using the capital asset pricing model should use a higher riskless rate than the Treasury rate**; a company with a beta of zero cannot raise funds at the Treasury rate. In essence, the convenience premium reflects the money-like convenience services offered by government bonds,

[106] Oxera (May 2020), 'Are sovereign yields the risk-free rate for the CAPM?', prepared for the Energy Networks Association
[107] Krishnamurthy, A. and Vissing-Jorgensen, A (2012), 'The Aggregate Demand for Treasury Debt', *Journal of Political Economy*, **120**:2, April, pp. 233–67.

which have special safety and liquidity characteristics. This is currently not incorporated in Ofgem's Cost of Equity indexation methodology.[108]

ii. **The gap between corporate and sovereign risk-free financing rates.** The CAPM assumes that all investors can borrow and lend at the same risk-free rate. However, in reality, non-sovereign investors with even the highest creditworthiness face higher borrowing rates than those faced by governments.

3.106 In their seminal Corporate Finance textbook, Berk and DeMarzo (2014) comment that due to the above reasons, '**practitioners sometimes use rates from the highest quality corporate bonds in place of Treasury rates in [the CAPM equation]**' [emphasis added].[109] In line with this recommendation, Oxera assess the empirical evidence on the spread between the spot yields on ILGs and those on bonds with low default risk, namely AAA-rated corporate bonds. Oxera also observe the spreads from AA-rated corporate bonds as a cross-check.

3.107 Oxera's empirical analysis shows that over the last six months the spreads of AAA-rated corporate bonds yields relative to ILG yields range from 70–80bp*.* Recognising that AAA-rated bond yields reflect a non-zero probability of default, Oxera consider how much of the observed AAA yield represents compensation for expected loss and a premium for systematic risk. Based on the academic evidence, Oxera find that at a 10-year horizon the yields on AAA-rated corporate bonds minus up to 5bp to account for a default risk premium is a reasonable proxy for the RFR to use in the CAPM. For investment horizons up to 20 years, the evidence suggests a downwards adjustment of 5-20bp to AAA-rated corporate bond yields due to the increased default probability with increased investment horizons.

3.108 Based on spot yields (31 July 2020) of AAA bonds with maturity dates greater than 15 years (i.e. iBoxx £ corp AAA 15yr+ index) and including the recommended adjustment and the expected increase in yields implied from forward rates, Oxera's approach implies a real-CPIH RFR assumption of -1.15% to -1.00% (real-CPIH) over RIIO-T2.[110]

3.109 Despite the issues present in using government bond yields as a proxy for the RFR estimate, in recognising their historic popularity Oxera recommend an additional approach which applies an upward adjustment or 'premium' to ILG yields to recognise the spread between AAA-rated corporate bonds and UK gilts – an approach consistent with that taken investment banking analysts. Based on empirical analysis of historic spreads and estimates from equity analysts, Oxera conclude on an upwards adjustment of 50 to 100 bps.[111] Using the average of this range, Oxera estimate an average RFR estimate of -0.90% (real-CPIH).

3.110 Based on the above, Oxera conclude that -1.00% (real-CPIH) is an appropriate assumption for the RFR for RIIO-T2.

FQ5. In light of RIIO-2 Draft Determinations and Ofwat's final determinations for PR19, do you believe that energy networks will hold similar systematic risk during RIIO-2 to water networks during PR19?

3.111 It is not possible to directly estimate the beta for a business that is not listed, such as SPT, accordingly a robust methodology must be found to estimate it. The absence of stock market data is overcome by calculating the betas of listed proxy companies. Ideally this proxy sample would be formed by 'pure-play' comparators i.e. companies that operate exclusively in the sector of interest. However, there may be few 'pure-play' comparators within a given industry, and therefore the sample of comparators needs to include companies similar in their exposure to systematic risk. The most important characteristics when assessing the appropriateness of comparators for estimating betas for pure-play GB energy networks are: the industry they operate in, the composition of their business mix and the regulatory framework which they operate under.

[108] See 'WACC allowance model.xlsx' published alongside the 2020 Draft Determinations.
[109] Berk and DeMarzo (2014), 'Corporate Finance. Third Edition', p. 404.
[110] Based on 3-month and 6-month averages of the yields of the £ corp AAA 15+, Oxera
[111] Oxera (September 2020), 'The cost of equity for RIIO-2', prepared for ENA, section 2.1

3.112 Given the lack of listed energy networks comparators in the UK – the only two listed companies that own energy networks subject to RIIO price controls are National Grid and SSE – Ofgem have chosen to expand their representative sample by also considering pure-play GB water networks (SVT and UU) as primary comparator companies based on CEPA's relative risk analysis that suggests they have several similar risk characteristics as GB pure-play energy networks. Ofgem have also considered CEPA's evidence on betas for their preferred sample of European networks comparators, whose asset beta range of 0.35-0.40 is broadly consistent with the 0.34-0.39 range estimated for UU and SVT.

3.113 The comparison between energy networks and water companies is generally acceptable in many areas within economic regulation (e.g. debt assessment, incentive package and cost benchmarking approach). However, we fundamentally disagree with Ofgem and CEPA's assertion that GB water networks be used as primary evidence when measuring beta risk for GB energy networks. We also disagree with Ofgem and CEPA's estimation method and comparator selection for European comparators.

3.114 We have previously set out in our response to the SSMC and detailed in our RIIO-T2 Business Plan as to why we do not consider it appropriate to place weight on beta estimates from the listed GB water networks when selecting an asset beta for SPT for RIIO-2. Although water networks are utilities and subject to a similar regulatory regime, they ultimately face a different set of business risks than energy networks. CEPA acknowledges this in their report to Ofgem, stating that water and energy networks cannot be considered perfect substitutes and that there are different sector specific drivers of risk that could imply that investors in energy networks face higher risks relative to investors in the water sector. NERA's comparative risk analysis shows that the fundamental risk of energy networks is greater than that faced by water networks due to the following reasons:

- The government's decarbonisation agenda is driving significant changes in the energy supply market with material uncertainty regarding the TOs future role due to the potential for increased levels of embedded generation and storage at the distribution level, which could lead to changes in the use of transmission networks at T2 and beyond.

- Greater system operability risk.

- Higher relative investment programme complexity: taking into account factors such as the size of the project, the number of projects and interlinkages with other projects, Ofgem concluded at T1 that electricity TOs' capital investment projects were even more complex than those of GT and GD and had a greater number of major linked projects.

- Increased Complexity and Uncertainty from Multiple Competition Models: Ofgem's extended competition model proposals, competition proxy model (CPM) and special purpose vehicle (SPV) model, which are to proceed ahead of the proposed CATO framework, would expose TOs to greater risk through higher construction and operational risks, as well as the difficulty in designing long-term contracts that accommodate all contingencies over the life of the contract. SPT supports competition where this delivers value to the consumer. The above models are 'fake competition' and introduce more uncertainty into the price control.

3.115 Ofgem's proposal that GB water networks face similar risks as GB pure-play energy networks can ultimately be rejected by looking at the empirical evidence. The historical beta analysis conducted by NERA and Oxera indicate that energy networks (NG and SSE) asset betas have been consistently higher than those of water networks (UU, SVT and PNN) over time, reflecting a different risk profile between sectors, as can be seen in Table 4 and Figure 5 below. We would also draw attention to the divergence in in energy and water networks asset betas over the recent COVID-19 period. Whereas SSE's and NG's asset betas have maintained their sharp increase from March 2020, when the COVID-19 pandemic and associated economic lock-down occurred, the water network betas have instead declined over the same period after their initial jump. This evidence could imply that energy networks face higher systematic risk than water companies during the COVID-19 period.

Table 4 – UK water and energy network betas: NG and SSE asset beta is higher than water networks

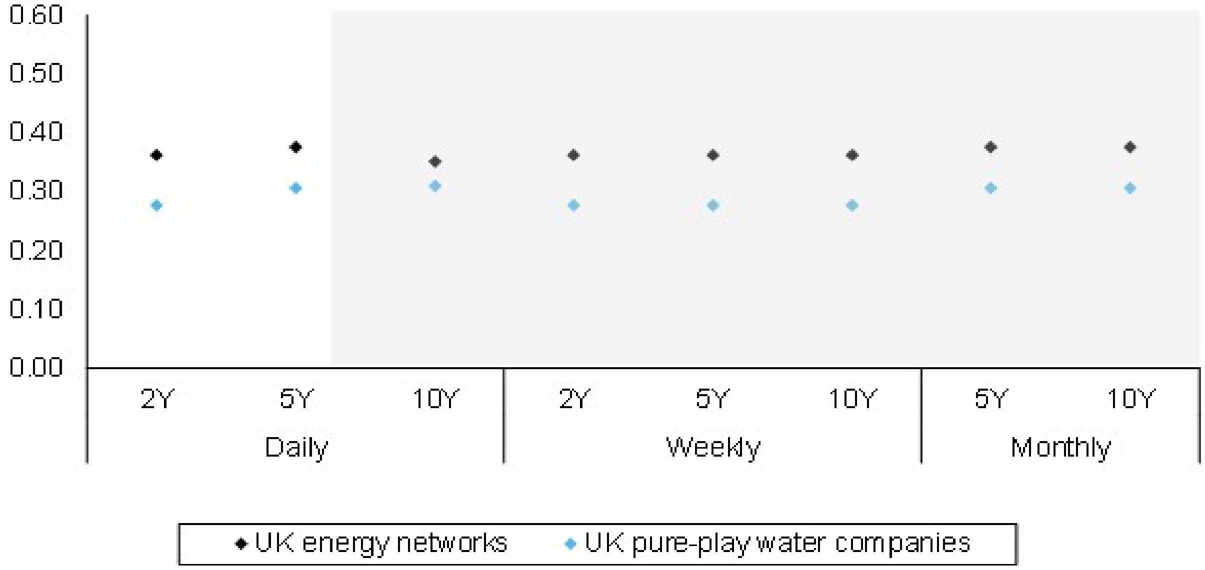
Source: NERA (September 2020), 'Cost of Capital for SPT in RIIO-T2', table 3.1

	Averaging period			
Estimation period	**Today/Spot**	**Last Year**	**Last 2 Years**	**Last 5 Years**
All comparators				
2-year daily	0.37	0.34	0.35	0.40
5-year daily	0.39	0.40	0.41	0.39
2-year weekly	0.37	0.34	0.36	0.42
5-year weekly	0.40	0.40	0.41	0.39
Pennon				
2-year daily	0.30	0.31	0.33	0.39
5-year daily	0.35	0.38	0.39	0.38
2-year weekly	0.29	0.34	0.39	0.44
5-year weekly	0.36	0.41	0.43	0.41
UU				
2-year daily	0.27	0.29	0.29	0.34
5-year daily	0.30	0.33	0.34	0.33
2-year weekly	0.30	0.29	0.31	0.36
5-year weekly	0.33	0.35	0.36	0.35
SVT				
2-year daily	0.28	0.29	0.30	0.35
5-year daily	0.31	0.34	0.35	0.35
2-year weekly	0.29	0.29	0.33	0.38
5-year weekly	0.33	0.36	0.37	0.37
NG				
2-year daily	0.36	0.34	0.36	0.39
5-year daily	0.37	0.38	0.38	0.37
2-year weekly	0.35	0.33	0.37	0.40
5-year weekly	0.37	0.38	0.39	0.36
SSE				
2-year daily	0.63	0.48	0.44	0.55
5-year daily	0.64	0.58	0.57	0.54
2-year weekly	0.61	0.44	0.42	0.50
5-year weekly	0.61	0.52	0.51	0.47

Source: NERA analysis, including Pennon, UU, SVT, NG and SSE. We assume 0.05 debt beta. Information date is 21 July 2020 (weekly returns we used 17 July 2020). Asset beta is calculated using gearing based on book value of net debt.

Figure 5 – Comparison of asset betas for UK energy networks and UK pure-play water companies

Source: Oxera (August 2020), 'The cost of equity for RIIO-2 – Q3 2020 update', figure 3.7



Note: The cut-off date is 31 July 2020.

3.116 Setting the beta for SPT over RIIO-2 based on water networks would understate SPT's true beta risk. NG is therefore the most direct comparator for SPT and selecting an asset beta for SPT in line with that estimated for NG is appropriate given that they will face a similar level of systematic risk. Using an estimation methodology in line with the approach used by the CMA in the Provisional Findings for NERL – 2 and 5 year estimation periods and daily estimates – but not placing weight on recent averaging periods, NERA estimate that NG's asset beta is on average 0.38.

3.117 In fact it should be noted that CEPA, Ofgem's economic advisors recognise that there are differences between water and electricity companies by stating that:

> "*In light of the similarities, we consider that a suitable starting hypothesis is that GB water networks would be considered by many investors to be a reasonable investment substitute for GB regulated energy networks and hence informative as to the latter's asset beta.* ***Within this, however, there are aspects of risk exposure that are difficult to conclude on decisively and they cannot be considered perfect substitutes.***
>
> *However, depending on the weight placed on different components of risk we recognise that energy networks may be judged riskier than water networks (though the converse may also be also true in relation to some sources of uncertainty such as climate change and resulting water resource pressure). Investment in energy networks will be driven by factors such as the expected long-term use of gas and electricity networks (e.g. in supply of heating or power generation).* ***Equity holders in energy networks are invested in long-lived assets and so their expected returns in the sector may be sensitive to these long-term drivers and the cashflow risks they may create, to the extent they are cyclical and systematic.***
>
> ***As a consequence, European energy networks as a comparator group and investment substitute to a GB energy network may more closely reflect these sector-specific risks that GB energy networks are exposed to."***[112]

[112] CEPA (July 2020), RIIO-2: Beta estimation issues, p.38.

3.118 We would note that NG's group beta also likely understates the true asset beta of its UK regulated business as its composite beta reflects its lower risk regulated operations in the US. Updating their decomposition analysis in their 2019 WACC report, NERA arrive at an inferred NG GB asset beta in the range of 0.45 to 0.52, above NG's group beta. This result is also consistent with the preliminary analysis produced by Indepen, which Ofgem relies on for arriving at its asset beta range. Indepen found that NG's US betas are 0.15 to 0.19 lower than NG's UK betas.[113]

3.119 Ofgem and CEPA reject the beta decomposition analysis on the basis that there are practical issues in decomposing NG and SSE's group betas and argue that decomposed results for NG's inferred asset beta are more volatile than either GB water or European energy comparators. CEPA also present evidence of inferred GB network beta by decomposing US listed PPL, which owns Western Power Distribution (WPD), showing significantly lower beta estimates than the inferred GB beta based on NG and SSE, as well as GB water network comparators. CEPA and Ofgem conclude that translating the evidence from SVT and UU is less challenging than translating from decomposition of NG or SSE's group beta, when estimating the risk of a pure-play GB energy network.[114]

3.120 NERA show however that CEPA have compared the volatilities of individual inferred betas with the average of multiple water and European energy comparator betas, which are smoothed and less volatile as a result of the averaging, resulting in an exaggerated volatility comparison. They note that the volatility of NG's inferred GB beta is within the range of CEPA's own European energy comparator set, demonstrating that NG's inferred beta is no more volatile than the European energy networks. Additionally, CEPA's WPD inferred beta shows a highly volatile pattern of the past five years – more than double the volatility of NG's inferred GB beta and above the upper bounds of the European comparators. The WPD inferred beta estimate from PPL is therefore unreliable and likely reflects idiosyncratic elements that only affects PPL or WPD, but not for other energy networks.

3.121 Acknowledging that European energy networks are an appropriate comparator and investment substitute to GB energy networks, considering that they reflect the sector-specific risks that GB energy networks are exposed to, CEPA draw on a sample of European comparators to inform their asset beta range. As argued in our SSMC response and in our Business plan, the underlying business risk between UK and European energy networks are closely aligned and should be more similar than two different industries inside the same country. It is therefore necessary to include European comparators in the beta assessment to ensure an adequately-sized comparator sample.

3.122 Based on their four selection criteria, CEPA have identified a comparator sample of six companies for their European beta analysis. CEPA's list includes four comparators also considered by NERA and Oxera in their reports (Red Electrica, Tern Retem, Enagas and Snam), along with two additional networks (Elia, a TO operating in Belgium and Germany, and REN, a Spanish transmission network). However, we have concerns with selection criteria approach adopted by CEPA when determining their European sample, as well as their approach to beta estimation. Both these approaches have the effect of understating betas for European comparators.

3.123 NERA have analysed CEPA's comparator sample and have found that CEPA have included an illiquid stock in Elia. Highlighting that CEPA's liquidity screening is only based on quoted bid-ask spread, which academic studies consider is not sufficient to determining liquidity alone, NERA supplement the liquidity filtering process by also considering trading volumes which they argue provide a measure of stock liquidity based on market breadth and depth and can equally be used to assess the robustness of the beta estimate. NERA find that Elia has the lowest trading volumes of all European comparators (including Acea and Naturgy), which likely explains its low asset beta estimate. As it provides unreliable beta estimates, Elia should therefore be excluded from the comparator sample.

3.124 NERA also highlight that CEPA have wrongly neglected Naturgy (a Spanish gas distribution operator) and Acea (an electricity distribution operator in Italy) in their assessment based on the incorrect claim that both companies have *"very low proportions of regulated activities".* In actuality, both Acea and Naturgy have substantial share of regulated business: Naturgy has a regulated share of EBITDA of 64% in 2019; Acea's

[113] Indepen (2018), 'Ofgem Beta Study – RIIO-2 Main report', pp. 38–9
[114] CEPA (July 2020), RIIO-2: Beta estimation issues, p.7.

regulated share of EBITDA was 81% in 2019, and consistently above 76% for the last 6 six years. Both shares are also well above CEPA's own selection criteria threshold of 50% of regulated activities. The inclusion of Acea and Naturgy improves the overall robustness of the European asset beta assessment and as such they should be included within the comparator sample as reasonable references for GB regulated network. This recommendation is backed up by NERA's relative risk assessment which shows that both companies bear similar risks as SPT.

3.125 In line with recommendations from NERA and Oxera, as well as UK and European regulatory precedent, we also take into consideration empirically estimated betas from European comparators. When correcting for CEPA's errors in its sample selection and employing the CMA preferred estimation methodology, NERA find an empirical asset beta range for European comparators between 0.38 to 0.40, ultimately drawing on the upper-quartile range for the European comparators of 0.40. NERA's recommended asset beta range is in line with the 0.38-0.41 range estimated by Oxera, where they lower bound is based on NG's five-year asset beta and the upper bound is based on the average five-year asset beta from their NG and European comparator set.

FQ6. Is there evidence of a material difference in systematic risk between:
a) RIIO-1 and RIIO-2,
b) distribution and transmission networks,
c) gas transmission and electricity transmission,
d) gas and electricity?

<u>a) RIIO-1 and RIIO-2</u>

3.126 We consider that investors face greater risks under RIIO-2 rather than RIIO-1 regime, and this is supported by rating agency comments on the riskiness to the regime. Although Moody's maintain its Aaa sub-rating for the stability and predictability of the regime, Moody's note that the framework has deteriorated from a risk perspective, notably given Ofgem's reduction to the allowed return for assumed outperformance.[115] Moody's has also put National Grid and its subsidiaries on negative outlook, in part citing the forthcoming price control and materially reduced scope for financial outperformance compared to the current control.[116]

Table 5: New Mechanisms and Changes Comparative to RIIO-1

Policy Area	Risk
Business Plan Assessment	The operation of the new methodology for assessing the Business Plans, is highly subjective and penalises companies based on an opaque set of benchmarks. Also, companies are exposed to ex-post adjustments for the Business Plan Incentive through Consumer Value Propositions.
Allowed Versus Expected Returns	The creation of an adjustment to account for allowed versus expected performance which is an arbitrary and unprecedented adjustment, unreflective of future performance.
Return Adjustment Mechanisms	RAMs will cap the performance of companies and claw back any further outperformance, thus blunting TOs' incentive to find efficiencies which are then shared with consumers.
Competition Models	The introduction of three new and ambiguous competition models which will impact future large-scale investments, without any evidence of benefits to consumers.
Level of Returns	The reduction to the cost of capital to an all-time low for GB networks will not attract the necessary investment to support the UKs green recovery.
Incentives (ODIs)	A significantly reduced and asymmetric package, with a significant downside and little upside. This will incentivise "safety first" behaviour by TOs when innovation is required. It will not incentivise changes required for Net Zero and will place an

[115] For further detail see: NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 3.5.4
[116] Moody's (24 August 2020) Moody's changes outlook on National Grid plc and most subsidiaries to negative; affirms ratings

	unreasonable liability on TOs.
Pre-construction	New mechanisms result in greater risk being borne by TOs for pre-construction, despite the criticality of such projects being higher than ever before for Net Zero and security of supply reasons.
Large Project Delivery	A new Project Delay Charge as part of the Large Project Delivery incentive will penalise TOs for delays due to matters outside their control. This unfairly exposes companies to risks outside of their control.
Stakeholder Engagement Process	It is not clear to us that Ofgem have utilised the more complex stakeholder engagement process they have created and failed to reflect the views of the User Group and Ofgem's own Challenge Group.
Ex-Post Price Control Deliverables (PCDs)	Ofgem are suggesting that there could be an after the event adjustment to allowances if PCDs are not delivered in accordance with the Final Determination.

(b), (c) and (d)

3.127 We argue that transmission networks face greater competition risks compared to other networks, given Ofgem proposals to introduce a CPM and SPV model, which can proceed ahead of the CATO regime[117], and has identified a number of projects which it expects to subject to CPM or SPV approach. In its DD, Ofgem has committed to increasing early and late competition models over RIIO-2.[118] SPT supports competition where this will deliver value to the consumer. These models as proposed are likely to expose TOs to greater risk, given the greater construction[119] and operational risks,[120] as well as the difficulty in designing long-term contracts that accommodate all contingencies over the life of the contract. SPT continues to support the Early CATO model which is the only competition model which is 'real competition', not fake competition.

3.128 TOs also face greater risks than most other energy networks from the higher relative investment complexity of its investment programme. Taking into account factors such as the size of the project, the more bespoke nature of projects, the number of projects and interlinkages with other projects, Ofgem concluded at T1 that electricity TOs' capital investment projects were more complex than those of GT and GD.

3.129 This view is also backed up when looking at the assessed capex/RAV ratios for SPT against GDNs (and water companies). Ofgem used capex/RAV ratios to inform its relative risk analysis at RIIO-1[121], noting that companies with a higher capex to RAV ratios are more exposed to cash flow risks, and thus face higher risk than those with smaller capex programmes.[122] NERA show that for RIIO-2, SPT have higher capex/RAV ratios than the GDNs (7-12% versus 5-7% when looking at baseline totex illustrative totex respectively), which imply greater relative capex size and higher investment risks for SPT.[123] This observation is also seen when comparing against water company capex/RAV ratios and when looking at RIIO-1 levels.

3.130 As mentioned in FQ5, the UK and Scottish government's decarbonisation agenda and drive towards Net Zero is driving significant changes in the energy supply market. Traditional centralised sources of generation are being replaced by a more divergent mix of generations sources, which present material uncertainty regarding the TOs future role at T2 and beyond e.g. the potential for increased levels of embedded generation and storage at the distribution level.

[117] Ofgem (2018), Impact Assessment on applying the PSV and CPM to future new, separable and high value projects, p. 14
[118] Ofgem (2020) Consultation - RIIO-2 Draft Determinations - Core Document, p. 108
[119] Ofgem states that construction and delivery risk will remain largely with the TO but with "*sharing factor for underspend and efficient overspend*". Thus, Ofgem intends to subject over-spends to efficiency test, which increases regulatory risk relative to the RIIO counterfactual where there is no such qualification. Ofgem (July 2018) Hinkley-Seabank project: decision on delivery model, Appendix 3.
[120] TOs are exposed to a higher level of risk as operational and maintenance cost allowances are set over the contract period as opposed to subject to periodic review. The CPM/SPV approach thereby exposes the TO greater risk from asset failure that increase cost, and unexpected increases in the cost itself. Ofgem (July 2018) Hinkley-Seabank project: decision on delivery model, Appendix 3
[121] Ofgem (2012), RIIO-GD1: Final Proposals - Finance and uncertainty supporting document, para. 3.14, 3.17. Ofgem (July 2020) Consultation - RIIO-2 Draft Determinations – Finance Annex, p. 52, para 3.63.
[122] *"We consider the ratio of capex to RAV to be a better indicator of the riskiness of an investment programme than simply looking at absolute capex levels. This approach is also consistent with the considerations of the major credit rating agencies. Where this ratio is higher, we consider the company to be potentially exposed to higher cash flow risk, and vice versa."* See: Ofgem (2012), RIIO-GD1: Final Proposals - Finance and uncertainty supporting document, para. 3.17.
[123] NERA (September 2020), Cost of Capital for SPT in RIIO-T2, section 3.5

FQ7. Do you have any views on how we should consider further the gearing impact on beta and cost of capital estimates?

3.131 The motivation for this cross-check has sought to address the concern, brought to attention by the CMA in the NERL redetermination, around the positive relationship observed between gearing and the cost of capital due to the common approach to re-gearing the asset beta, in violation of the standard MM theory that the cost of capital is independent of (and therefore broadly constant with) gearing. Ofgem has investigated the implied cost of equity from the MM model, calculating the WACC for each of their five UK comparator companies, drawing on observed raw equity betas at observed gearing levels, combined with their set of CAPM-WACC assumptions. Ofgem then uses these WACC values to derive the cost of equity inferred assuming a 60% notional gearing assumption based on a flat WACC hypotheses.

3.132 Ofgem concludes through this cross-check that the common approach to re-gearing asset betas has the effect of increasing the WACC. Ofgem states that the impact of this is that the cost of capital increases by 10bps for each 5-percentage point increase in gearing.[124] Based on their findings from this approach Ofgem concludes that for companies with observed gearing levels close to 60% (UU and PNN), the cost of equity is similar to the observed cost of equity. As such, Ofgem suggest whether they should place more weight on "*raw equity betas for UU and PNN such that the notional equity beta remains in line with the most applicable market data*".[125] To supplement this, Ofgem asks whether it should align its notional gearing with observed gearing for the preferred comparators.

3.133 SPEN, along with other energy networks, have provided views on the issue between gearing and the cost of capital as part of the ENA's evidence submissions as a third party in the appeals process for the CMA's PR19 redeterminations. Based on the analysis conducted by Oxera in their recent reports[126], the violation seen by Ofgem of the MM theory is considerably reduced or eliminated when correcting for the errors made by Ofgem in their application of the MM model.

3.134 Oxera finds that the MM analysis assumes that 'the firm borrows at the market rate of interest'. This means that the MM test should be based against the cost of new debt alone and should not include embedded debt. Ofgem does not make this distinction in its Cost of Debt estimate, assuming a 1.74% Cost of Debt for the estimation of the observed WACC which incorrectly uses a historical average, and not the forward-looking Cost of Debt assumed by MM.

3.135 Oxera shows that when the weight of new debt is set at 100%, the variation of WACC with gearing becomes less noticeable compared to that under the CMA's original approach. As stated in our response to FQ4, Oxera finds that the cause of the upward relationship is attributed to the RFR being set too low, resulting in an underestimate of the cost of equity at all gearing levels. Adopting a higher RFR which has been adjusted for the gap between sovereign and corporate debt yields will address the inconsistency with Ofgem's CAPM parameters and financial theory. Using a RFR based on more plausible levels, as well as correcting for the estimates of debt beta and the TMR, Oxera find that the MM cross-check produces WACC estimates that remain relatively flat across different gearing levels (i.e. not very sensitive to gearing), but with the equity betas increasing[127]. This is consistent with the MM theorem that higher levels of gearing are translated into higher Cost of Equity, but with a stable WACC estimate.

3.136 We do not agree with Ofgem using raw equity betas for the water companies as they do not reflect the beta risk faced by SPT for the reasons outlined in FQ5. Using betas from NG provides the most viable and direct beta risk comparison for SPT, and NG's figures do not support Ofgem's assumption of 4.2% Cost of Equity.

3.137 Ultimately Ofgem's cross-check does not support its proposed Cost of Equity and there is no case to use raw equity betas and observed gearing.

[124] Ofgem (2020) Consultation – RIIO-2 Draft Determinations – Finance Annex, p. 54.
[125] Ofgem (2020) Consultation – RIIO-2 Draft Determinations – Finance Annex, para. 3.75, p. 55.
[126] Reference Oxera report for CMA PR19 and Oxera cost of equity report for ENA
[127] Oxera (September 2020), The cost of equity for RIIO-2 – Q3 2020 update, section 5.8

FQ8. Do you agree with our interpretation of cross-checks?

3.138 We do not agree with Ofgem's interpretation of cross-checks used in Step 2 to arrive at the baseline Cost of Equity allowance in the Draft Determination. Ofgem have utilised a number of other sources on return to cross-check their CAPM-implied Cost of Equity. These include: updated evidence on Market-to-Asset Ratios (MARs), OFTO returns, investment managers' forecasts, and an updated sample of infrastructure funds. Ofgem state that these cross-checks support revising the CAPM-implied Cost of Equity at 60% notional gearing downwards from 4.3% to 4.2% (real-CPIH).

3.139 In this section, we analyse the validity of the various cross-check methodologies proposed by Ofgem for RIIO-2. We find that the evidence from these cross-checks do not support a lower Cost of Equity compared to the CAPM estimates as Ofgem have indicated, with several being unreliable evidence sources and indeed some actually supporting returns at a higher level. These cross-checks are ultimately based on evidence derived from comparators that are not analogous to TOs(e.g. OFTOs and infrastructure funds). Ofgem should not place any weight on these pieces of evidence when cross-checking the CAPM-implied Cost of Equity.

<u>OFTO returns</u>

3.140 Ofgem consider the implied equity IRRs from winning OFTO bids. Using the most recent OFTO tender round bids, Ofgem cites an average nominal equity IRR estimate of 7.0% (nominal), or 4.9% (real, CPIH). Ofgem acknowledges that these structures are associated with high levels of gearing (around 80-90%) and that drawing inferences for the notional energy network, which has gearing levels between 55-60%, is therefore problematic. However, Ofgem seems to ignore this point, concluding that if it were to adjust for gearing, the OFTO bid evidence would support the mid-point or low-end of their CAPM range.

3.141 We consider that OFTO IRRs are an unreliable estimator for the Cost of Equity. As highlighted by NERA, bidders for OFTO projects are evaluated based on their proposed bid's revenue stream over the OFTO licence period.[128] Even where equity IRRs targeted by investors for OFTO projects are stated in the bidding documents, the equity IRR is likely to understate the expected return given potential cost outperformance, tax, and financing outperformance over the operational life. In addition, the risk profile of OFTO operational asset will be lower than the risks faced by an onshore energy network company which undertakes a portfolio of capital and replacement activities and operational activities under a materially different regulatory regime. Any comparison of the asset risk between the two will therefore be invalid and will likely significantly underestimate the Cost of Equity.

3.142 It is also difficult to verify this piece of evidence as the data on OFTO bids has not been made publicly available. It is therefore not possible to replicate the derivation of the equity IRRs to confirm if it is relevant to cross-checking returns for onshore networks. As such, OFTO bid IRRs cannot be used to infer the allowed Cost of Equity for energy networks under the RIIO-2 framework. We have been advised by Ofgem that this data is confidential, however, as this data forms part of the CAPM cross checks, we believe this should be made available to the relevant regulatory experts on a confidential basis.

<u>Investment managers' forecasts</u>

3.143 Ofgem has provided updated estimated return figures published by investment managers and advisors used to cross-check its TMR range, which it claims support an average nominal TMR of 7.10%. Once combined with Ofgem's assumptions on the RFR and the equity beta, the TMR projections can be used as a cross-check to the CAPM-implied Cost of Equity.

3.144 Ofgem even notes that many of the reports from the same investment managers are not comparable between the two periods due to changes in assumptions on investment horizons and changes in the

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

geographical source of the data. These changes appear to explain the perceived decline in Ofgem's TMR cross-check.

3.145 Oxera has conducted a review of each investment manager's report used in Ofgem's cross-check and find that nearly the entirety of the decline in Ofgem's estimated TMR is due to a change in the investment horizon for Schroders.[129] If the original horizon had been used for comparison, Ofgem would have reported a TMR of 7.90% rather than 4.90% for them. The new value is an extreme outlier as it has based its UK projections on US data. This data point should be disregarded as it is an obvious data outlier and is not a direct UK estimate.

3.146 The other driver in the decline is the negative change in Blackrock's estimate. As noted by Ofgem, this is not a like-for-like comparison due to changes from an EU TMR in December 2018 to a UK TMR in December 2019. Oxera find that Blackrock's current analysis suggests that it projects lower returns due to expected declines in corporate earnings and dividend yields, not because market risk has decreased. We also agree with Ofgem's view that given the impact of COVID-19, which has materialised since December 2019, these forecasts may now be out of date.

3.147 Oxera concludes that excluding these two data points, the TMR estimated by investment managers remains unchanged than that presented in the SSMD, and indeed the evidence appears to support a TMR more in line with those proposed by Oxera and NERA.

3.148 We have already set out our reservations in our Business Plan submission in relation to the use of this source of evidence on forward-looking equity market returns. As highlighted by NERA[130], survey evidence is unreliable in informing investors' expected returns as respondents' answers are highly sensitive to the framing of the question and how it's phrased. Respondents have also been found to exhibit a tendency to extrapolate from recent realised returns. These issues make interpreting this evidence challenging. Ultimately the results are based purely on judgement, which can be heavily influenced by the respondent's own position or biases and are therefore less reliable than estimates based on market evidence.

3.149 For similar reasons listed above, the CMA criticised the use of survey evidence in its 2014 NIE determination and in the most recent NERL Provisional Findings and instead focusses on historical data.[131] In the NERL appeal, the CMA highlight the sampling issues with survey evidence using the UK TMR range reported in the Fernandez survey, which is actually more than 100 bps higher than Ofgem's own survey evidence. [132] The TMR reported in the survey for the UK is between 4.3 and 20% with a standard deviation of 2.4%, further highlighting the sensitivity of the results to the sample size and framing issues.[133]

3.150 Ofgem has accepted that the investor managers' forecasts are based on geometric returns and appear to add 0.82% to derive the arithmetic averages. Ofgem acknowledges that the required adjustment is uncertain, and the size of the adjustment likely understates the TMR given higher adjustments recommend by others.[134]

3.151 Overall, our recommendation still stands that this evidence source does not provide a meaningful cross-check to the TMR and Ofgem's calculation does not provide a robust cross-check of the CAPM-implied Cost of Equity as it uses a less well justified input value for the TMR in the CAPM formula.

[129] Ofgem (July 2020), RIIO-2 Draft Determinations – Finance Annex, Table 23.
[130] NERA (September 2020), 'Cost of Capital for SPT in RIIO-2', section 4.2.3
[131] At NERL, CMA states: *"[…] the results of such surveys tend to depend on the identity and outlook of the respondents and how they interpret the questions being asked. Some surveys do not clarify the time frame over which the parameters are to be estimated (the long-term equilibrium ERP or a shorter-term estimate); whether an arithmetic or geometric averaging approach should be used."* See: CMA (2020) NATS (En Route) Plc/ CAA Regulatory Appeal, p. 189 para 12.230
[132] CMA (2020) NATS (En Route) Plc/ CAA Regulatory Appeal, p. 176 para 12.177. Link: https://assets.publishing.service.gov.uk/media/5e7a2644d3bf7f52f7c871f3/Provisional_Findings_Report_-_NATS_-_CAA.pdf
[133] Fernandez, P. (2019) Market risk premium, and risk-free rate used for 69 countries in 2019: a survey Table 4, p. 13-6. Link: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3358901
[134] Wright et al report a difference in geometric and arithmetic means of between 1-2%. See: Wright, S. et al (2018) Estimating the cost of capital for implementation of price controls by UK Regulators, E-125.

Infrastructure fund discount rates

3.152 Ofgem has changed their approach for this evidence source from the SSMD by considering a wider sample infrastructure funds, presenting evidence from fourteen instead of six funds. They also draw on time-series data for discount rates and premium to NAV, which they state implies an equity IRR of 6.3% (on a simple average) or 6.5% (weighted average), implying a real equity IRR of around 4.2-4.4%.

3.153 Oxera conducted a comprehensive review of the risk and return characteristics of the various infrastructure funds and found that the funds' asset composition instead points to portfolio risk that is likely lower than that of energy networks.[135] This is primarily due to the large proportion of several of the funds' portfolios being comprised of investments that are considered lower risk compared to regulated utilities, such as PPP projects, social housing and availability-based investments.

3.154 Additionally, Oxera also found that where funds' portfolio investments face volume or revenue risks higher than those exposed to energy networks, these were generally hedged through long-term (or availability-based) contracts and some investments are supported via some form of government support mechanisms which reduces their risk e.g. renewable obligation certificates (ROCs). In their review of the Ofgem's wider sample of infrastructure funds used in the Draft Determination, Oxera find that the asset classes and the risk of the diversified company portfolios share no similar characteristics to a 'pure-play' energy network business.

3.155 In addition, the equity IRRs quoted by Ofgem reflect the potential discount or premium of the funds relative to the net asset value (NAV).[136] Ofgem implicitly assumes that the NAV premium or discount reflects a difference in the market view of the discount rate that should be applied to these funds and the assumed fund discount rate. However, the discount/premium can also reflect differences around other assumptions used to form the NAV, such as assumed future cash-flows. Assuming an overall premium to NAV, the fund discount rates will be higher than equity IRRs.

3.156 In addition, as Ofgem acknowledges, it has not adjusted the IRRs for any difference in business or financial risk (i.e. leverage) that impairs the comparability of these discount rates or equity IRRs to energy networks.

3.157 Due to the fundamental differences in the risk profile and the errors used in inferring the equity IRR, the discount rates used by infrastructure funds are not considered to be an appropriate benchmark for cross-checking the cost of equity for RIIO-2.

MARs

3.158 MARs are defined as the ratio of the market price to the underlying assets: the regulated asset value (the RAV). Ofgem use this ratio to assess whether investors are paying a premium to own network assets i.e. their expected return exceeds their cost of capital. This is indicated by a MAR greater than 1.

3.159 In its recent report for Ofgem, CEPA estimated MARs for listed UK water and energy companies to infer investor views of the cost of equity for the energy sector at RIIO-2. It estimates positive MAR premia of between c. 10% and 40% for UK water and energy companies.[137] Ofgem have relied primarily on CEPA's estimated MAR premia of around 20% for UK water companies at 31 December 2019 (post Ofwat's PR19 final determination) to justify that the allowed return on equity is more generous than market expectations and that a 10bps downwards revision to their allowed return on equity to 4.2% is acceptable.[138] Ofgem also

[135] Oxera, 2019, Infrastructure fund discount rates – Prepared for Energy Networks Association, London: Energy Networks Association.
[136] As Ofgem notes, under certain assumptions the relationship between the implied equity IRR and the fund discount rate is as follows:
$$\text{Equity IRR} = \frac{\boldsymbol{FundDiscountRate}}{\boldsymbol{FundSharePrice}/\boldsymbol{FundNAVpershare}}$$

[137] CEPA (July 2020), RIIO-2: Use of market evidence, pp.21-22.
[138] *"The MARs cross-check is persuasive. As noted at paragraphs 3.67 to 3.74, market reactions to Ofwat's allowed return on equity of 4.19% (appointee level) is, we expect, priced into MAR values for UU, SVT and PNN. Compared to other cross-checks there are fewer comparison issues, given the consistent notional gearing of 60% and the view that systematic risk is similar for energy and water networks."* Ofgem (July 2020), RIIO-2 Draft Determinations – Finance Annex, p.66.

draws on CEPA's estimated MAR premia for NG and SSE of 10-20% to inform the size of their Outperformance Wedge adjustment in step 3.

3.160 NERA show in their report that sizeable and uncertain adjustments need to be made in order to be able to make any inferences about investors' cost of capital from market capitalisation data.[139] The enterprise value of water companies is driven by a number of factors which are unrelated to the cost of capital and which need to be removed from the raw MAR estimates to calculate an adjusted MAR for the wholesale business. NERA show that CEPA's analysis only adjusts the observed MARs to account for non-UK and non-regulated businesses. CEPA have failed to account in their analysis for the other adjustments for non-wholesale regulated activities, pension deficits and future expected outperformance of water companies. This adjustment omission explains part of CEPA's residual RAV premium. NERA evidence that when adjusting for the above factors in the water companies' raw MARs, the value of the adjustments are found to be uncertain. The sum of all the adjustments (13- 39% for SVT and 7-31% for UU) is able to explain the observed RAV premium of 22% and 21% for SVT and UU, respectively.

3.161 We disagree with CEPA that NG and SSE should be included in the MAR analysis, as neither companies are 'pure-play' UK regulated energy networks. For NG it would involve adjusting its market value for its substantive US operations. NERA find that the scale and uncertainty of the value of NG US operations, which represent around half of its asset value make it difficult to draw any meaningful conclusions on MARs for its GB networks.[140] Analyst estimates of the value of US regulated activities and non-regulated activities vary widely, with the estimated MAR lying in the wide range of between 0.33 and 1.37, this is before adjusting for expected outperformance over the remaining years of RIIO-1, and subsequent reviews. The MARs is therefore overstated. Analyst estimates of value of US regulated activities and non-regulated activities vary widely[141], with the estimated MAR lying in the wide range of between 0.33 and 1.37, this is before adjusting for expected outperformance over the remaining years of RIIO-1, and subsequent reviews. The MARs is therefore overstated.

3.162 Oxera's research in MARs[142] also find that CEPA and Ofgem have failed to take into account all relevant adjustments that affect the company valuation. They state that the uncertainty over the sources of value premia and their respective valuations, make it difficult to conclude from the evidence of traded market premia if the cost of equity is set lower than the allowed return.

3.163 Once the raw MARs are adjusted to take into account all the relevant factors that explain company valuations, there is no strong evidence to conclude that adjusted MARs for the UK water wholesale business are above 1 and therefore that the allowed return on equity exceeds investors' expected cost of equity. Given the magnitude and variation of the required adjustments, the MAR evidence presented by Ofgem is not a reliable method to cross-check the CAPM-implied cost of equity.

Alternative cross-checks

3.164 When cross-checking the CAPM-implied Cost of Equity, we recommend the use of the asset risk premium (ARP) and debt risk premium (DRP) differential (or ARP vs DRP) cross-check proposed by Oxera.[143] The cross-check tests whether the allowed Cost of Equity proposed by Ofgem meets a required differential between the risk premium on energy network assets and the risk premium on the investment-grade bonds issued by network companies.[144] The test is based on the financial theoretical principle that an equity investment offers a higher risk premium than that of holding high-quality debt given that equity investors are residual claimants to the company's cash flows relative to debt investors i.e. the ARP should be larger than the DRP.

[139] NERA (September 2020), 'Cost of Capital for SPT in RIIO-2', section 4.1
[140] NERA (September 2020), 'Cost of Capital for SPT in RIIO-2', section 4.1
[141] For summary of analysts' estimates of the adjustments to National Grid's raw MARs please see NERA (September 2020), 'Cost of Capital for SPT in RIIO-T2', Appendix D.3.1
[142] Oxera (September 2020), The cost of equity for RIIO-2 – Q3 2020 update, appendix A2.5
[143] Oxera (September 2020), 'Asset risk premium relative to debt risk premium', a report prepared for the ENA.
[144] 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. The asset risk premium is calculated using the formula: Asset risk premium = Asset beta × ERP.

3.165 In line with Ofgem's comments in the SSMD, Oxera believe that the appropriate benchmark for the ARP−DRP differential should be derived from contemporaneous market evidence. Oxera has therefore updated their analysis of the ARP−DRP differential implied by yields on the bonds issued by UK utilities companies.[145] The updated methodology is broadly similar to that adopted previously by Oxera[146], however they now use: daily traded yields for UK energy bonds (as opposed to the yield upon issuance) over the 6 months preceding the publication date of the RIIO-2 Draft Determination (9 July 2020), have removed some utilities bonds from the analysis sample (including all water bonds), adopted a time-varying TMR to address concerns that listed companies in sample rely on a TMR drawn from regulatory precedents as empirical beta estimates are time-sensitive, as well as the inclusion of the revised approach to the RFR presented in a recent Oxera submission to the CMA.[147]

3.166 Oxera finds that the ARP−DRP differentials for UK energy bonds have increased over time. When using their updated approach detailed above, Oxera illustrate that the ARP-DRP differential implied by Ofgem's Draft Determination figures falls significantly below the recent market evidence. Oxera find that Ofgem's midpoint of their Cost of Equity allowance for RIIO-2 falls in the bottom 15th percentile of the contemporaneous market data from UK bonds, implying that Ofgem's allowance is too low and needs to be adjusted upwards to bring it in line with the contemporaneous market evidence. Indeed, in contrast to the Ofgem's Draft Determination allowances, past regulatory precedents for the UK energy sector over the last ten years have implied ARP−DRP differentials were broadly in line with those implied by the contemporaneously market evidence at the time. This strongly supports the argument that past regulatory precedents have not systematically overestimated the Cost of Equity allowances, and that the current price control has understated the allowed Cost of Equity.

3.167 Indeed, this percentile ranking is a conservative estimate as it includes a downward attenuation bias. Correcting for this would place Ofgem's implied ARP−DRP differential at a lower percentile ranking within the distribution of market evidence. Including also Ofgem's outperformance wedge adjustment would lower the implied ARP-DRP differential further.

3.168 Ofgem's percentile ranking has changed significantly since Oxera's previous analysis,[148] primarily driven by the errors made in their Cost of Capital allowances. Oxera show that the ARP−DRP differential implied by their recommended Cost of Equity range[149] is more in line with recent market evidence, being placed between the 24th percentile (low end) and the 58th percentile (high end) of the empirical distribution of contemporaneous market data.[150]

3.169 Clear inference from the above assessment is that Ofgem's Draft Determination proposals for the Cost of equity is understated relative to values observed in the market and thus Ofgem need to adjust their proposed CAPM parameter assumptions.

FQ9. What is your view on the overall in-the-round assessment of allowed returns to equity? Is our judgement of 3.95% at 60% notional gearing reflective of the combined analysis through Steps 1, 2, and 3?

3.170 We strongly support the principle of "aiming up" in relation to the cost of equity in order to attract adequate investment in GB in the next decade. It is important to be clear that the principle of aiming up is *not* to deliberately over-remunerate. In the absence of certainty around the **required** rate of return, the **allowed** return needs to match (or exceed) the required return for investment to be viable. However, due to the high level of uncertainty on, in particular, the cost of equity, there is no guarantee that the midpoint of a best-endeavours and reasonably judged range would turn out to be precisely the right level to satisfy this constraint. In this environment, given the adverse consequences of failure to invest, aiming up is an optimal regulatory response to the uncertainty inherent in estimating the cost of equity and the asymmetry of the consequences arising from setting the allowed return too high or too low. The purpose of aiming up is to

145 Oxera (September 2020), 'Asset risk premium relative to debt risk premium'
146 Oxera (March 2019), 'Risk premium on assets relative to debt' and Oxera (November 2019), 'The cost of equity for RIIO-2'
147 Oxera (May 2020), 'Are sovereign yields the risk-free rate for the CAPM?'
148 Oxera (March 2019), 'Risk premium on assets relative to debt'
149 Cost of Equity range of 6.00–7.08% (real-CPIH). See: Oxera (August 2020), The cost of equity for RIIO-2 – Q3 2020 update.
150 Oxera (September 2020), 'Asset risk premium relative to debt risk premium', section 4.2

maximise societal welfare (an objective that we do not consider controversial), not to systematically over-remunerate the company.

3.171 The intention of "aiming up" is not to offer a wedge over and above the true underlying cost of equity to shift incentives to invest more. It is to avoid inadvertently setting the cost of capital too low, given the asymmetric risks associated with failure to invest.

FQ10. What is your view on the expected outperformance estimate of 0.25% at 60% notional gearing? Do you recommend alternative analysis techniques or do you have suggested improvements to the analytical files published alongside this consultation?

3.172 We not only disagree with Ofgem's expected outperformance figure of 0.25% at 60% notional gearing, we fundamentally disagree with the concept of the outperformance wedge altogether and believe that in the context of the risks prevalent in today's economy with the potential longer-term economic disruption due to COVID-19, it should be scrapped altogether. In fact, there are very few examples of regulators choosing not to adopt the approach of aiming up, due to the real and material costs that can arise as a result of under investment. Ofgem's proposed Allowed v Expected returns adjustment in fact ignores the concept of aiming up and also in fact deducts 25bps.

3.173 Ofgem originally proposed an outperformance wedge of 50 bps, it has now proposed a reduced wedge of 25 bps. The mere fact that Ofgem previously considered that the evidence pointed to a wedge of at least 50 bps, whereas it now considers the evidence points to a wedge of 25 bps, tells us something about the difficulty of calibrating a wedge of this kind. Ofgem has also failed to recognise when estimating RIIO-2 expected outperformance that it has set a one size fits all approach.

3.174 We disagree with the assertion that investors expect positive outperformance due to the presence of information asymmetry that is argued to automatically mean that a regulator will set a generous price control. Instead, asymmetry can just as easily cause a regulator to set price controls that underfund a company for its licensed activities. As demonstrated empirically by Frontier Economics and First Economics, the historical evidence of performance against previous price control decisions shows performance has varied widely by regulated sector. With no evidence of systematic outperformance regulation is therefore not a one-way bet.

3.175 Frontier Economics present possible reasons for expected outperformance. The first being that the regulator simply gets its calculations wrong during a price review, resulting in a generous package to the companies purely due to the poor quality of assessments undertaken by the regulator and not due to the presence of information asymmetry. Although this reason can also work in the opposite way with the regulator mistakenly setting allowed revenues at too low a level for the company. The second reason being that although the framework may provide companies with a 'fair bet' at the onset of the price control, such that the company has a roughly equal opportunity of outperforming or underperforming against the package, the risks that take shape over the period, either positive or negative, will inevitably lead to a deviation between the ER and the AR (up or down). Lastly, and most importantly, incentive-based regulation is designed to provide companies with the possibility of outperformance to encourage them to make cost efficiency gains and make service quality improvements. A regulated company responding positively to these regulatory incentives and achieving an ER greater than the AR is the desirable outcome that a regulator should seek. This outcome will result in customers not only being passed down benefits during the price control, via sharing mechanisms, but will also benefit in the long-run from lower bills and better service quality due to the best practice efficiencies on cost and performance revealed by regulated companies which regulators then factor in when setting the new efficiency frontier for the subsequent price control.

3.176 Historical evidence, considered over a suitable time horizon, shows that outperformance by energy networks has varied widely by sector and that regulation is not a one-way bet. Fundamentally, experience from previous controls is not a predictor of future performance, as the efficiencies revealed by the regulated company through their performance on the overall financial package of a price control will be shared with customers and the targets are re-based via the reset of the subsequent price control – the scope for outperformance will be different. Investors cannot make expectations of outperformance from a price control which has not yet been set, and one that has a significantly different risk and reward profile than that of the previous price control. Ofgem arbitrarily setting the outperformance wedge based primarily on network's performance during RIIO-1 is therefore conceptually flawed, as well as unjustified, as the final outcomes of that price control are still unknown.

3.177 Overall, making an arbitrary adjustment to correct for the perception that expected outperformance is guaranteed based on the network companies achieving the outcomes which the RIIO framework was designed to encourage is unjustified and conceptually incorrect. Despite the challenges presented by information asymmetry, we do not believe there has been substantial justification given as to as to why regulators are not capable of setting a price control which provides the average regulated company with a 'fair bet' using the regulatory toolkit available to them. If Ofgem believe that the level of outperformance for RIIO-2 needs to be reduced, the correct approach would be to correctly calibrate the incentive and cost target mechanisms utilising the regulatory toolkit in place so as to reduce the scope for outperformance and ensuring that outperformance is achieved when companies deliver efficient outputs in line with what stakeholders expect.

3.178 Recent historical levels of outperformance are not representative of potential outperformance in RIIO-2 because the changes that Ofgem is considering implementing for RIIO-2 would curtail markedly the scope for outperformance. Other UK regulators do not seem to believe that there is a need to put in such mechanisms at the cost of curbing incentives.

3.179 The introduction of this downwards adjustment to base returns could likely to a range of unintended and negative consequences that will ultimately harm consumers and the sector as a whole. Frontier identify and outline some of the key implications being: the erosion of investor confidence and increased investor risk; weakened incentives for efficiency and innovation; the distortion of incentives to invest; and the loss of clarity over price control calibration. In their recent report, Frontier estimate the potential harm that arises as a result of the weakening of incentives that would inevitably arise if an outperformance wedge (calibrated based on the basis of past performance) was implemented.[151] They find that where 10% of the net productivity gains in the energy sector are removed by the outperformance wedge (a reasonably conservative scenario), the annual loss in cost savings due to compromised productivity gains would outweigh the gain (from the 25 bps deduction) by 2027/28.

3.180 It is ours, and others' belief, that Ofgem's proposed adjustment to baseline returns is arbitrary and is a policy that has been based on a flawed conceptual and evidential basis. The adoption of such an adjustment is unprecedented by any other regulator within a price control settlement and would have negative implications on companies' delivery incentives and financeability. It will distort investor's confidence in the sector and weaken incentives, ultimately leading to poor consumer outcomes.

FQ11. What is your view on an ex-post adjustment for baseline equity returns? Is there an alternative mechanism or implementation approach that you think could better meet our stated objectives? Do you have specific views on averaging, pooling or suggested simplifications?

3.181 There is no precedent for an ex-post adjustment for baseline equity returns by regulators. We understand Ofgem's intensions of wanting to safeguard network companies with the proposed ex-post adjustment to baseline equity returns in the event that realised outperformance in RIIO-2 is less than expected. However, our view is that this mechanism would distort incentives during the price control. If a company was expected to experience weak performance at say 2/3 years into the control, they would have no incentive to seek cost savings, and on the contrary may have an incentive to spend up as this would be compensated through the ex-post agreement. We believe that this impact of weakened incentives would ultimately harm consumers as a result of diminished productivity in the sector, which would lead to higher costs in the long-run.

3.182 Frontier Economics has carried out a detailed assessment on the potential outperformance suggesting an expected underperformance.[152] With the penalties associated with TO Common ODIs, we believe there is a risk of underperformance for TOs also.

[151] Frontier Economics (August 2020), 'Further Comment on Ofgem's Proposal to Adjust Baseline Allowed Returns', section 3
[152] Frontier Economics (August 2020), 'Further Comment on Ofgem's Proposal to Adjust Baseline Allowed Returns', section 5

FQ12. Do you agree with our approach to assessing financeability?

3.183 Ofgem has conducted an “in the round” assessment of financeability for the RIIO-2 period with the focus very much on the debt finance of a notional company and very little regard to actual company parameters or the financeability of equity. This is at odds with the analysis that companies where instructed to provide along with their Business plan submissions.

Overview of process

3.184 We welcome Ofgem’s view on ratios that companies should be aiming for and that the target for the industry should be to remain two notches above investment grade. This provides benefits to the consumer through lower interest costs while providing the industry with the previously afforded headroom in past price control periods to deal with market shocks such as the financial crash of 2008 or more recently the Covid-19 crisis. Therefore, Ofgem have indicated that they will not in principle seek to lower the credit quality of the sector as a whole.

3.185 Although an “in the round” assessment has merit, the impact on individual ratios and importance places on them by external parties such as investors and credit ratings agencies should not be ignored. One such ratio is the adjusted interest cover ratio (AICR) which is a key indicator of a company’s ability to pay upkeep on its debts. Furthermore, Ofgem’s analysis fails to cover the financeability of the actual companies and the impacts to cash flows resulting from the RIIO-T1 close out process or how the proposed changes to annual price control mechanisms (i.e. AIP).

3.186 Ofgem have also made adjustments to the assumptions around the financial structures of notional company which have drastically improved the implied credit ratios but may not reflect the real-world characteristics of companies. An example of this is increase in the assumption of CPIH index linked debt from 25% to 30% based on an average of the network operators. Although this may be the case the disparity between companies is wide with some companies such as SPT holding no index linked debt whereas others such a NGET holding higher levels than the average. Another consideration is that availability of CPIH linked debt as most of the index linked debt currently held by companies will be aligned to RPI.

3.187 Ofgem have indicated that they believe that their proposals to Indexation both the Cost of Debt & cost of equity insulate the companies from some macroeconomic factors such as movements in interest rates and have also been used as a check on long term viability and outlook of the TO’s.

Debt financeability

3.188 We have not received details of the outputs from the assessment undertaken by Ofgem in terms of scenario analysis as this is not present within the published LiMo. One observation is that this does not seem to cover the same parameters as those undertaken by the Network Operators, in accordance with Ofgem’s business plan guidance[153], and the output of which would be beneficial to our understanding of Ofgem’s conclusions.

3.189 One major change indicated by Ofgem was in the adoption of a new index for the Cost of Debt which would replace the current iBoxx mechanism. As stated in our response to FQ1 this move could have a detrimental impact on the financeability of Network companies as current the new index does not reflect a similar credit quality of the network operators given it is a reflection of a wider pool of participants. This index is not anchored to a pre-set level of credit quality as with the previous mechanism such as 50/50 split between A and BBB rated instruments.

3.190 The views of Credit Rating Agencies must also be taken on board, Moody’s for example have recently commented that it is evident that perceived increases in social risks such as those following criticism from outside influences such as responding to political influence etc. have led to the regulator diverging at the margin from established practice such as the implementation of Expected Versus Allowed adjustments. These changes represent a departure from established regulatory practice, adherence to which has

[153] RIIO-2 Business Plan Guidance 9 September 2019

supported widespread confidence in the stability and predictability of the regime. As such, this can only be viewed as credit negative in the long run. Further to this, they have also put National Grid Group on negative watch due to their exposure to forthcoming regulatory determinations. Specifically, due to the proposed cut to allowed equity returns by around half, on a like-for-like basis, and materially reduce the scope for financial outperformance compared to the current price control. This will materialise in the context of limited headroom and reflects the risk that the group and the wider industry may not maintain a financial profile in line with Moody's guidance for the Baa1 rating.

3.191 Pressure on metrics will be exacerbated by the impact of the COVID-19 pandemic which should not be ignored due to the longer-term impact this could have on the wider economy, notably on inflation. Ofgem's stress testing of financeability needs to reflect the cash collection risk, which it is proposed will pass to the TOs in T2. In addition, the annual revenues of regulated energy networks are directly linked to an inflation index, including through the RAV, exposing them to a significant risk from low inflation.

3.192 The majority of the Transmission sector's debt is at fixed rates of interest. Prolonged low inflation would therefore lead to a relative reduction in cash flow and a weakening of a network's financial profile, a credit negative. Networks in GB are vulnerable to low inflation scenarios due to the regulatory funding model i.e. real return based on an inflation based RAV. This model leads to a "Cash flow gap" as the Nominal interest debt raised by Networks is paid down by a real return with the Inflation proportion added to RAV and paid over time. The lower the inflation, the weaker the asset base on which to borrow. This was a specific scenario looked at by Ofgem as part of the required company analysis.

Equity financeability

3.193 From the draft determination Ofgem have focused most of their analysis on debt financeability, however seem to have provided little in the way of evidence that the RIIO-T2 price control is financeable of an equity basis. The justification provided is that dividend assumption is calibration in line with market expectations in line with dividend yield and future RAV growth (Capital gain). This is augmented with the proposal to index the risk-free rate. However, the proposals for RIIO-T2 have not been universally accepted by the range of investors with the level of return questioned at a time where investment in the electricity network will be fundamental to the delivery of the UK's Net Zero ambitions. These views can be illustrated by the recently published Bernstein report that argues that Ofgem are "stuck in austerity" mode with the current draft determination proposals not compatible with the sufficient investments requirements to achieve the proposed level of decarbonisation. If anything, this does little to keep investment flowing into the UK. This is illustrated by the fact allowed returns are not at the levels on offer elsewhere with returns in the USA circa 300bps higher than those proposed. Further to this, the package as a whole also does little incentives for innovation or risk-taking and creates a greater level of uncertainty due to the move away from ex ante allowances which does not reflect the level of risk currently mirrored by the proposed WACC values.

3.194 Furthermore, we do not agree with the inclusion of Expected Vs Allowed related cash flows in the financeability assessment. This is due to the fact that there is no guarantee that the cash flows from this adjustment will be received during the period. Ofgem have proposed an ex post true up mechanism however the proposal is not company specific and would be applied on an electricity transmission sector basis therefore it is plausible that SPT could end up in a scenario where the intended return is not realised and no true up would be implemented.

Comparability across sectors

3.195 We do not agree with the proposal the WACC should be consistent across the Gas and Electricity Transmission sectors given the differences in gearing.

3.196 It is a highly plausible scenario that shareholders in the electricity transmission sector, after consideration of the scale of reduction in cost of equity, would prefer a higher notional gearing, above the 55% reflected in the draft determination, if the WACC will remain unchanged at a higher gearing and therefore reduce its commitment equity with no impact on the CoC.

3.197 The arguments for providing a lower level of gearing from Ofgem was to take account of the higher level of risk involved with the delivery of the required Totex in the regulatory period. It is inconsistent not to recognise this through a higher cost of equity.

3.198 This approach is another derivation from RIIO1 where Ofgem explicitly adopted a higher WACC for the two smaller electricity transmission companies. The higher WACC was due to a lower gearing at 55%, compared to 60% for NGET. Gearing was set lower to reflect the scale and complexity of the two smaller TOs capital investment programme. Given that the investment requirements across RIIO-1 and RIIO-2 are comparable the change in assumption is not justified. Ofgem should reflect in it assessment of the cost of equity that SPT will be subject to greater levels of risk than in RIIO-1 and reflect for example the changes currently proposed around revenue collection and risk of over/under recovery and the move to greater levels of competition within regulatory framework.

3.199 Furthermore, there is a lack of fairness in the proposed common incentives package on offer across the industries as the proposals for gas companies are materially higher than those in electricity (0.45 Vs 0.25 RORE bps on average).

3.200 Alignment of CoC with water is also incorrect due to levels of risk involved in both sectors which has been observed in price control periods. This has been an established precedent due to the fact that the nature of projects undertaken in electricity, particularly transmission, involves significantly higher risk than those in the water sector. If anything, it could be argued that the level of disparity has only increased due to the considerable uncertainty involved in the transition to net zero.

3.201 Finally, the expected RORE ranges for the electricity transmission operators are significantly lower than that of the listed UK water networks companies with the water companies on average, able to achieve a RORE in the range of 7.2% - 0.2% and transmission operators only able to achieve a range between 4.5% - 1.8% RORE operators a much lower and narrower RORE window. Totex sharing rates are also lower, with 31%-39% in electricity transmission versus ~50% in water and gas distribution.

3.202 Therefore we believe that the level of risk that the electricity transmission companies will be exposed to during RIIO-2 and the level of proposed return are not consistent when compared to the water and gas sectors and therefore the package as a whole cannot be deemed to be financeable on an equity basis.

FQ13. Do you agree with our approach to determining notional gearing for each notional company?

3.203 We consider Ofgem's approach to assessing the appropriate notional gearing to be adequate. This is due to the fact that it was very similar to approach to our own assessment process by using the RoRE ranges to ensure level of risk is acceptable.

3.204 On the Financeability assessment undertaken, we welcome the view that Ofgem have recognised that insufficient headroom was available under the 60% gearing assumption given the analysis provided as part of our Business Plan submission and the move to 55% gearing is welcome due to impact this will have on financial resilience. However due to the sculpting of WACC to match gearing at 60% the calibration of this change has no benefit to the equity investor even given the high risks outlined by Ofgem in the draft determination as a reason to effect this change. We do not believe that this is correct and it is discussed in more detail to the response to FQ12.

FQ14. Do you have any evidence that would suggest we should consider adjusting our notional company financing assumptions due to the impact of COVID-19?

3.205 In relation to the notional company a longer-term view over RIIO-T2 should be taken and at this point in time, with the exception of revenue risk from the proposal to transfer revenue collection risk to the TOs, we do not forecast an ongoing Covid-19 impact requiring adjustments to the notional company financing.

3.206 The change currently proposed for revenue collection and over/under recovery transferring to TOs is particularly acute currently due to the COVID-19 impact on revenues and is a marked higher risk exposure from RIIO-1. This risk should be modelled as part of the stress testing of the financing assumptions.

FQ15. Do you agree with our proposal to pursue Option A?

3.207 We agree with the proposal to pursue option A providing a notional tax allowance to compensate companies for their efficient corporation tax costs.

FQ16. Do you agree with our proposals to roll forward capital allowance balances and to make allocation and allowance rates Variable Values in the RIIO-2 PCFM?

3.208 We agree with the proposal to roll forward capital allowance balances; this aligns with policy set for ED1 and ensure customers the correct amount of tax over the assets' lives. We also agree with Ofgem's proposal to make allocation and tax rates used to calculate variable values in the RIIO-2 PCFM; to better capture companies' actual tax position.

FQ17. Do you agree with the proposed additional protections? In particular:
a) do you have any views on a materiality threshold for the tax reconciliation? Do you think that the "deadband" used in RIIO-1 is an appropriate threshold to use?

3.209 We agree with greater transparency of any variances between tax allowances and taxes actually paid to HMRC. However, this should not solely be based on the review of one price control period but should cover the total tax allowances obtained for the cost of network assets over their life. It is a very complex area attempting to separate regulatory allowance from other impacts on taxation paid to HMRC in a particular year. It is therefore appropriate to apply a materiality threshold for residual differences. We look forward to working with Ofgem in developing a template for the tax reconciliation.

b) Do you have any views on our proposals to retain the Tax Trigger and Tax Clawback mechanisms from RIIO-1?

3.210 We agree with Ofgem's proposal to retain the Tax Trigger and Tax Clawback mechanisms from RIIO-1.

c) Do you have any views on the proposed process for the Tax Review?

3.211 In principle, we are supportive of a tax review mechanism which would review the appropriateness of a tax allowance for significant events such as a change in ownership, however, due to the complexity around timing, it would be more appropriate to review any unexplained differences between notional and actual tax at the end of the price control period post submission of the period end CT600 form. We agree with Ofgem's proposal to carry out a preliminary review prior to triggering a formal tax review.

d) Do you have any views on the proposed board assurance statement?

3.212 In principle, we are supportive of a board assurance statement to provide additional comfort over the appropriateness of the values in the tax reconciliation. However, as recognised by Ofgem, tax is a complex area and any additional assurance must take this into consideration. As SPEN completes its tax returns on a calendar year basis, this adds further complexity to the tax reconciliation process.

FQ18. Do you agree with our proposal to introduce a symmetrical RAMs mechanism as described above?

3.213 As outlined within our SSDM response, we do not support the principle of a Revenue Adjustment Mechanism as the price control should be calibrated appropriately and outperformance should be encouraged as this demonstrates that companies are beating their targets and improving performance, delivering better outcomes for consumers. Therefore, any RAMs mechanism must allow for reasonable and genuine outperformance opportunities from efficiencies. The mechanism should focus on TOTEX underspends. This is an ex-poste adjustment which in principle we would discourage, however, we do recognise the regulators concerns at the scale of some companies' outperformance in RIIO-1 due to TOTEX underspends.

3.214 In principle, the introduction of a RAMs mechanism should be on a symmetrical basis as the intent of this mechanism is to control for unanticipated financial outcomes either upside or downside during the RIIO-2 period.

3.215 However, the current draft determination parameters are skewed to the downside in terms of potential RoRE outcomes therefore it could be suggested that the mechanism should take account of the asymmetrical nature of the proposed incentives.

FQ19. Do you agree with our proposal to introduce a single threshold level of 300 basis points either side of the baseline allowed return on equity?

3.216 Considering that as incentives are capped at +27bps/-105bps, and current BPI penalty of -23bps , Totex underperformance would have to reach circa 25% to reach bottom end & totex outperformance of 35% to breach the parameters set. This seems extremely unlikely due to the level of totex already removed from the company proposals. However as stated in the response to FQ18, the intent of the mechanism is to correct for extreme unintended outcomes, therefore the parameters seem reasonable. This threshold should be revisited at RIIO-ED2 as we do not believe the 300ps can be applied industry wide as DNOs have differing mechanisms and incentives to TOs.

FQ20. Do you have any other comments on our proposals for RAMs in RIIO-2?

3.217 The 300bps value may require to be revisited in RIIO-ED2 depending on the scope of the parameters and package set as part of the ED2 price control as companies should not be penalised for fair outperformance.

FQ21. Do you agree with our proposal to implement CPIH inflation?

3.218 We agree in principle with movement to CPIH inflation, given the move away from RPI as the official inflation measure in the UK. However currently the proposal would see the companies move to CPI not CPIH and these may diverge in the future. Ofgem should also recognise the limitations of CPIH. For example, in the Cost of Debt and indexed linked debt. The move will have a financial impact as the costs of moving from RPI index lined debt to CPI(H) linked debt at the scale proposed by Ofgem. We are not convinced that the markets will have the required availability of this type of debt.

FQ22. Do you agree with our proposals, including the policy alignment for GT and GD, and to recover backlog depreciation for GT RAV additions (2002 to 2021) over 20 years from the start of RIIO-2?

3.219 We see no reason why aligning the gas sectors by front ending RAV depreciation in the gas transmission sector is an unreasonable proposal.

FQ23. Do you agree with our proposed assumptions for capitalisation rates?

3.220 In principle we agree with the alignment of the statutory capitalisation rate and the regulatory capitalisation rate by implementing the natural rate as per the proposed allowances.

3.221 However, further consideration is required to account for the complexity of a move away from an overall rate for the price control to a flexible rate with annual true up will bring. Although in theory this may improve financeability due to more reflective cash flows on required investment. The ability of the price control processes to implement such a change has yet to be demonstrated and would bring about further uncertainty.

3.222 Therefore, we would not welcome ex post changes to baseline capitalisation rates as this provides additional uncertainty which will be multiplied by the new forecasting approach for the AIP. However, a form of revision could be beneficial for Uncertainty Mechanisms (UMs) considering the Totex requirements for these projects are still uncertain. This could be calibrated on an annual basis during the price control as an ex post true up at the end of RIIO-2 would not provide the cash flow benefit outlined above as the investment would have already been undertaken.

3.223 For UMs, we believe that further clarification will be required to ensure the natural rate is applied as with the proposed approach with baseline expenditure. We are happy to work with Ofgem on this area to ensure that there is clarity around the information that is currently being used to set these parameters given the impact they can have on price control revenues.

FQ24. For one or more of the aggregations of totex we display in Table 40, should we update rates ex-post to reflect reported outturn proportions for capex and opex?

3.224 As stated in the response to FQ24, our view would be that the allocation or natural rate for baseline expenditure should be fixed as these costs are certain and should not majorly deviate during the price control. However, UM should be allowed to flex to provide the cash flow benefit of investment during period as previously stated. A mechanism for this could be built into the AIP and undertaken on an annual basis. Further review will be required once the license drafting and RIIO-2 price control models have been shared to evaluate how this could be implemented on a practical basis.

FQ25. Do you agree with our proposal to use the closing RIIO-1 RAV balances as opening balances for RIIO-2?

3.225 Yes, this approach is sensible as there will be an extensive close out process that will revise the closing balances at the end of RIIO-1.

3.226 Consideration need to be given to movements between the BP submission in Dec19 and the values published in the regulatory submissions made in August20 as these will reflected both actuals for 2019/20 and latest forecast of 2020/21. Furthermore, the impact that these values may have on final determination values such as Base revenues which are used to set incentives must also be considered.

FQ26. Do you agree with our proposal to use estimated opening RIIO-2 balances until we have finalised the closing RIIO-1 RAV balances?

3.227 Yes, this approach is sensible however consideration should be given to availability of new information since BP19 submission for example 19/20 actuals or any new evidence in relation to close out adjustments to reduce the level of true up required in the RIIO-2 period (2021/22).

FQ27. Do you agree with the three categories of adjustments outlined below?

3.228 Yes, adjustments are required for all 3 categories outlined; opening/closing balances (RAV/Tax etc), revenue true ups (incentives/pass through / inflation etc) and MOD (Both 19/20 & 20/21). MOD will continue to be calculated via the RIIO-1 PCFM as well as the existing incentive regime.

3.229 The Opening Balance adjustments for RAV/Tax etc have been forecast via our BP submission and more recently in our Regulatory Financial Performance Report (RFPR).

FQ28. Do you agree with our approach in using estimated values for closeout adjustments until we are able to close out the RIIO-1 price controls?

3.230 Yes, this approach is sensible however any adjustment made must be based on the principles of certainty of outcome and on level of materiality. Therefore, if the outcome is uncertain and materiality is low we believe no forecast adjustment should be applied to the RIIO-2 final determinations.

FQ29. Do you agree that proceeds from the disposal of assets during RIIO-2 should be netted-off against totex from the year in which the proceeds occur?

3.231 Yes, this approach is currently undertaken in ED-1 and a similar exercise will be undertaken in RIIO-1 close out with regards to T1. A further review of the relevant licence condition will be required to ensure consistent treatment across sectors.

FQ30. Do you agree that we should carry out a review where an asset is transferred to a holding company and then subsequently sold to a third party?

3.232 We do not see any reason why this cannot be introduced. However further clarification will be required around the ownership of the assets in question for example have they been funded by the customer (UK consumer) or fully funded by the company.

FQ31. Do you agree with our proposal to apply one interest rate to revisions to PCFM inputs and charging errors, based on a short-term Cost of Debt?

3.233 Our position is we see no reason to change the established framework, which is equitable and consistent with investor expectations. Therefore:

- Under- and over-recoveries against the revenue cap should roll forward at a benchmark interest rate as they do in RIIO-1 and have done in previous price controls. We see no reason to change the established practise.
- Prior year adjustments relating to expenditure items should generally roll forward at the allowed cost of capital

3.234 The base rate plus a margin is a suitable interest/discount rate when a company can reasonably be expected to accommodate the movement of cashflows across years via a short-term bank facility (or equivalent), but that the cost of capital ought to be used when timing adjustments entail a more substantial investor commitment and/or take effect over a longer duration.

3.235 We have commissioned First Economics to produce a report on the subject which we have attached. The report details out the arguments around why we do not feel Ofgem proposal is appropriate.

3.236 In principle, Under- and over-recoveries against the revenue cap should roll forward at a base rate plus margin interest rate as they do in RIIO-1 and have done in previous price controls. This reflects the short-term nature and scale of these types of adjustments due to the nature of the true up required. However Prior year adjustments relating to expenditure items should roll forward at the allowed cost of capital as when a company is not permitted to recover revenues in relations to these costs, be that a timing difference, or a reopener, investors have to step in to finance the mismatch between costs and revenues. This is also true for the opposite scenario where financing requirements may not be required and scaled back due to lower investment requirements which rightly should be returned to the consumer.

3.237 Therefore, we believe the existing approach is equitable and regulated companies' capital requirements should be treated in a homogeneous way with adjustments for an advance / delayed return in line with the underlying applicable cost of capital for the regulated business.

FQ32. Do you agree with the margin-based approach, and the methodology used to calculate a margin of 110bps?

3.238 The calculation approach seems reasonable and consistent with the historic calculation.

FQ33. Do you have any reason why the marginal cost of capital for revisions to PCFM inputs and charging errors should remain distinct from each other, or why WACC may remain a more appropriate time value of money for a particular subset of prior year adjustments?

3.239 Fundamentally, it should be recognised that the expense incurred by a company in relation to investment changes comprise not just the investment cash outlays but also the cost of financing their activities. The current approach of using WACC for Totex true-ups results in companies being in the same position in value terms had the investment plans out turned exactly as forecast.

3.240 In practice when investment plans differ from those set at the beginning of a price control, companies need investors to finance any delay in revenues. Historically Ofgem has recognised that the capital requirements had a cost and judged that there was no reason to think that the cost was any different to the regulated company's cost of capital, as applied to investor capital that was held formally within the RAV. We see no reason as to why this assumption will not be the same during RIIO-2 and beyond.

3.241 Therefore, we believe Ofgem's proposed approach to time value of money adjustments for prior year true-ups is not appropriate.

3.242 Three key tests should be applied to determine the appropriate rate; the funding requirements (i.e. via bank facility or Investors), the period over which the adjustment is required, and the materiality of the adjustment in question. Therefore, under these tests managing the under- and over-recovery of revenues would be short term funded, low value and so continuing to use interest payable/receivable in years when corrections are required is reasonable. However, it is a very different proposition if companies are potentially being asked to deal with much bigger amounts of under- or over-remuneration and/or if balances are being carried forward for periods that extend beyond a year. These are not circumstances in which companies would typically look towards working capital. Rather, they constitute a call on the main investor to step in.

3.243 We therefore do not agree with a default assumption across all prior year adjustments. Please see First Economics' "RIIO-2: Prior Year Adjustments" report for further details[154]

FQ34. Do you agree with our proposal to include forecasts for most PCFM variable values for the purposes of the AIP?

3.244 Forecast PCFM variables will reduce the magnitude of true-ups and streamline reporting. Initiatives of this nature we support and in theory should reduce potential cash flow issues if actual expenditure is substantially higher than base allowances as historically this would take 2 years before the cashflows would be added to base revenues. However, this would also increase the variability of annual revenues and could potentially impact on the certainty required by energy suppliers in terms of impacts on customer bills. We believe that further clarification is required to see if this volatility can be absorbed into the current wider price regimes within the energy sectors. Also, further detail is required via the relevant license conditions and proposed Price Control Financial Model(PCFM) to ensure that these can be implemented appropriately.

FQ35. Considering re-openers as set out in these Draft Determinations, do you agree with our proposal to exclude them from any forecasting? If not, please submit specific examples or analysis of the potential materiality of actual spend versus initial allowances.

3.245 Historically reopeners have been excluded from forecasts/PCFM and added through the price control period especially in RIIO-1 with the longer price control period. However, given the "scale" of investment that may be required to be funded via reopeners during RIIO-2 and the reduction of the length of the period this may prove problematic due to the potential cash flow issues arising from unfunded spend early in the period.

3.246 Ofgem needs to reflect the potential scale of expenditure that may be required via reopeners, through its stress testing of financeability. The output from financeability stress testing needs to demonstrate the

[154] First Economics (August 2020), 'RIIO-2: Prior Year Adjustments', prepared for the Energy Networks Association

company can maintain a comfortable investment grade rating, after funding all reopeners, to continuously comply with its licence and facilitate the raising of additional funds as required.

3.247 Also, there is a risk that expenditure may not be funded at least initially, which may impact on the appetite of the companies to spend in these areas. However, moving to a new "live" forecasting AIP process may reduce the burden on companies as true-ups will be actioned faster. Again, further detail is required to ensure both license conditions and proposed PCFM can implement this approach appropriately.

FQ36. Do you agree that additional reporting on executive pay/remuneration and dividend policies will help to improve the legitimacy and transparency of a company's performance under the price control?

3.248 The Company Accounts (Disclosure of Directors' Emoluments) Regulations 1997 is the relevant legislation that guides the disclosure of Directors remuneration. The Statutory and Regulatory Accounts of SPEN are audited for compliance with these regulations and are publicly available. The prescribed disclosure requirements in the Companies Act were set following detailed consultation. In addition in accordance with their licences electricity networks publish an annual Statement on 'linkages between Directors' Pay and Standards of Performance' (https://www.scottishpower.com/userfiles/file/SPEN_Links_directors_pay_and_standards_of_performance_2019.pdf).

3.249 We conclude:

- Informed reviewers of financial statements believe the relevant information is available;
- We believe the format and setting of information for this area should be determined by the Companies Act;
- Different formats and unaudited additional information may lead to confusion and misinterpretation; and
- There is no evidence to suggest this has been requested by stakeholders.

3.250 In relation to the question on dividend policy it would be far more constructive for the electricity networks and Ofgem to work collaboratively to educate stakeholders to reduce the existing knowledge gap in stakeholders that have led to misinformed commentary. There are many factors that will influence a Company's dividend profiles like gearing, pension deficit payment structures and past payment profiles. Educating stakeholders will best address interpretation issues in this area rather than complex statements some stakeholders may not fully understand.

FQ37. Do you agree with the proposed definition of Base Revenue?

3.251 'Base Revenue' is similar to previous price control periods, with NIA revenues now added (circa £10m) across period. A further change will see incentive revenues now added to ensure that the tax treatment is aligned unlike in RIIO-1 which is welcome. This change is a result of the proposal to move to "Live" revenues and incorporate all Revenue items into a "Super PCFM". We have no major opposition of to the change in definition to accomplish this. However, this is contingent on the correct license conditions and modelling approach being applied in practice.

FQ38. Do you agree with the proposal to fix the values used for ODI caps and collars at final determinations?

3.252 Given the scale of uncertain Totex spend that may occur in RIIO-T2, we would not propose to fix these values ex ante as with previous price controls due to the level of Base revenue increases that may be seen during the price control. Given that incentives will now form part of base revenue as outlined by Ofgem, consideration will be required in how the calculation of incentives could work if these values are not fixed ex ante however this is achievable. Outwith this element we see no reason why incentives should be fixed upfront.

Chapter 4: RPEs and Ongoing Efficiency

Introduction

4.1 We have material concerns with Ofgem's use and interpretation of evidence in determining Real Price Effects (**RPEs**) and in setting the frontier shift for RIIO-T2 in the Draft Determination. Ofgem relies heavily on a report from its economic consultants CEPA.[155] Ofgem's approach represents a flawed assessment of the available economic evidence that hampers companies' ability to recover their efficient costs. Of significant concern, is that Ofgem proposes an additional efficiency stretch of 1.2% per year for CAPEX and 1.4% per year for OPEX, which translates to £62m based on the Draft Determination TOTEX value. This does not, however, take into account cost efficiencies which we have already embedded into our Business Plan submission. An efficiency stretch totalling £145m was applied to our baseline plan by SPT. This comprised known efficiencies delivered through our innovation in design, increased utilisation of existing assets and other productivity improvements delivered over the course of T1 (£110m). A further 2.5% (£35m) efficiency stretch was incorporated in the RIIO-T2 baseline plan of £1375m. There is therefore a double count.

4.2 We recommend that Ofgem adopts the approach outlined in our RIIO-T2 Business Plan, whereby Ofgem sets an ex ante productivity target and an ex ante RPE allowance that offset each other, in effect indexing the price control to CPIH inflation. The current outlook for RPEs is within the range of evidence on long-term productivity growth, which suggests this approach is reasonable and would be a practical solution in current climate, and one that would significantly simplify the regulatory process.

4.3 In developing our response to Ofgem's frontier shift proposals in the Draft Determination, we and National Grid have commissioned NERA to provide and independent assessment of Ofgem's proposals and to advise on a recommend approach for RIIO-T2.[156] Our response below reflects the evidence from this report, as well as evidence from First Economics' report which focusses on the approach to estimating frontier productivity growth i.e. ongoing efficiency.[157] **The aforementioned reports are included in Annex 5 of this Draft Determination response.**

Ongoing efficiency

4.4 Of most concern is how Ofgem has interpreted CEPA's evidence on long-term productivity growth when justifying Ofgem's ongoing efficiency challenge for network companies for RIIO-2, adopting an approach which is arbitrary and inconsistent with regulatory precedent. Ofgem has selected the upper bound of CEPA's range when setting the ongoing efficiency challenge for RIIO-2, resulting in productivity targets that are higher than previously applied in any recent comparable GB regulatory decisions. Put simply, Ofgem's overestimated productivity improvement targets cannot credibly be achieved by regulated network companies over the RIIO-T2 period.

4.5 Adjusting for the errors made in CEPA's assessment and taking a prudent and realistic view of the available data based on the evidence on declining productivity growth in the macroeconomy, as well as the likely effects of COVID-19 on productivity growth, NERA identify an alternative ongoing efficiency challenge of around 0.3% p.a., significantly lower than Ofgem's Draft Determination estimates of 1.2% for capex and 1.4% for opex, which lack any credibility and do not address the significant and persistent drop in productivity growth since 2008.

4.6 Ofgem's efficiency stretch does also not take into account cost efficiencies which we have already embedded into our Business Plan submission. An efficiency stretch totalling £145m was applied to our baseline plan. This comprised of known efficiencies delivered through our innovation in design, increased utilisation of existing assets and other productivity improvements delivered over the course of T1 (£110m). A

[155] CEPA (May 2020), RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper.
[156] NERA (September 2020), 'Frontier Shift at RIIO-T2 Draft Determinations'
[157] First Economics (August 2020), 'Frontier Productivity Growth', Frontier Productivity Growth, a report prepared for the Energy Networks Association.

further 2.5% (£35m) efficiency stretch was incorporated in the RIIO-T2 baseline plan of £1375m. In effect, Ofgem's proposed ongoing efficiency is a double count.

Real Price Effects, (RPEs)

4.7 On RPEs, in contrast to Ofgem's approach at RIIO-T1, which included fixed ex ante RPE allowances, companies' allowances will now be indexed to outturn levels of each index.

4.8 This new indexation approach introduces new risks for transmission companies, especially where the indices themselves do not perfectly track external pressures in input costs. Ofgem has not appropriately considered whether the selected indices do effectively track changes in the TOs' costs, having not considered any alternative indices beyond those included at RIIO-1, which we have consistently argued do not adequately reflect our specialised costs.

4.9 Ofgem's indexation approach to RPEs is inconsistent with that taken for Ongoing Efficiency, which has been set as a fixed ex ante percentage, ignoring the theoretical and evidenced relationship between productivity and input prices.[158] Ofgem's proposal therefore ignores the tendency for these two terms to offset each other, and thus places additional risk on networks and customers alike. For example, in the event of a significant recession (likely with the impacts from COVID-19 and Brexit) a fall in both wages and labour productivity would likely occur. With Ofgem's proposals companies would be expected to face lower levels of wages to employees while still expecting ever-increasing levels of labour productivity.

4.10 Additionally, NERA show that the indices are relatively stable over time, but some have shown a sharp downturn as a result of the COVID-19 pandemic, particularly due to widespread use of furlough arrangements in other sectors.[159] The indices selected by Ofgem are likely to be more susceptible to volatility caused by COVID-19-related disruptions to the economy, causing unnecessary fluctuations in cash flows to companies and charges to customers with the proposed indexation approach. These fluctuations do not reflect our actual costs as an essential business with invariant changes to our demand for inputs. With these wider consequences in mind, a higher standard of evidence should have – and needs to – be applied to determining the appropriate input price indices if used for indexation.

4.11 Ofgem's approach to setting the Ongoing Efficiency challenge for RIIO-T2 is arbitrary and inconsistent with regulatory precedent. Ofgem has failed to account for the evidence of declining productivity growth in the UK economy, as well as the likely effects of COVID-19 on productivity growth, which have resulted in a productivity target for RIIO-T2 that cannot credibly be achieved by companies. Ofgem's approach of RPE indexation will introduce new risks for transmission companies, especially where the indices themselves do not perfectly track external pressures in input costs. This will be exacerbated by the current macroeconomic climate and the fact that any shocks to RPEs will not be offset by changes in the ongoing efficiency challenge.

4.12 When assessed against the available data on productivity improvement and in light of the uncertain outlook for the cost indices, a prudent solution would be to assume that that RPEs and ongoing efficiency will offset each other across the price control period, and the price control should instead be solely indexed to CPIH. This position is consistent with that which we outlined in our RIIO-T2 Business Plan submission. Ofgem should adopt this pragmatic and simple approach for setting the frontier shift for RIIO-T2 given the current economic climate.

[158] NERA (September 2020), 'Frontier Shift at RIIO-T2 Draft Determinations', section 3.1.2
[159] NERA (September 2020), 'Frontier Shift at RIIO-T2 Draft Determinations', section 3.3.3

Responses to Consultation Questions – RPEs and Ongoing Efficiency

Core Questions

Q10. Do you agree with our proposed RPEs allowances? Please specifically consider our proposed cost structures, assessment of materiality, and choice of indices in your answer.

4.13 Our positions are supported and evidenced in more depth in Chapter 3 of NERA's report on Frontier Shift.

4.14 In contrast to Ofgem's approach at RIIO-T1, which included fixed ex ante RPE allowances, under Ofgem's RIIO-T2 proposals, companies' allowances will be indexed to outturn levels of each index. Companies' ex ante allowances will be based on the latest available forecasts and replaced with outturn levels during the true-up process that happens after the conclusion of each year. We do not agree with the proposed RPE approach as there are material errors in Ofgem and CEPA's selection of indices.

4.15 Even if the selected indices perfectly track companies' external cost structures, the indexation approach adds volatility to revenue allowances and, as a result, to customer bills. This volatility and unpredictability are not desirable from a financing perspective or from the perspective of customers who wish to have stability in their bills.

4.16 Additionally, input price inflation and productivity improvements are closely correlated – a large macroeconomic shock (e.g. due to COVID-19 or the effects of Brexit) is likely to have parallel effects on both terms. By indexing RPEs but not ongoing efficiency, Ofgem would implicitly expect companies to benefit from reduced input costs while still achieving high productivity gains that rarely occur during recessions. In effect, even if the RPE indices are defined perfectly, the fluctuations in companies' overall revenue allowances are unlikely to reflect actual fluctuations in efficient costs.

<u>Flawed RPE index selection process</u>

4.17 By linking companies' allowances to actual movements in actual indices, companies' allowances are exposed to the short-term nuances of how each index is defined. Therefore, the selection process needs to incorporate a higher standard of evidence. That standard of evidence has not been met in this case: CEPA only considers the series used at RIIO-T1 against a very limited set of pass-fail criteria, finding that all series pass all criteria but providing no explanation as to how any one series passes any criterion.[160] The process it undertakes is materially pared down from how it proposed to carry it out this selection process in its June 2019 report. CEPA does not consider any indices beyond those used at RIIO-T1/GD1, and importantly, it fails to assess whether these indices accurately reflect year-to-year movements in transmission costs.

4.18 The additional volatility and revenue fluctuations which are unreflective of costs (described above) worsen when the RPE indices are incorrectly defined. CEPA has failed to provide the required transparency over the selection process meaning we do not have any confidence that they are well defined.

<u>Unjustified materiality threshold</u>

4.19 Ofgem's proposed cost structures are based on actual company-specific cost structures and so are likely to be cost reflective, so long as RPEs are applied to the cost structure of the final revenue allowances rather than business plan cost structures. The same logic applies to the materiality threshold, which, if used at all, should be assessed after unit cost and/or volume disallowances have been applied to business plans.

4.20 CEPA selects the cost categories which are material enough to include an RPE index for a particular company, based on whether the cost area is at least 10% of the company's costs. This materiality threshold is arbitrary and unjustified. CEPA states that it uses a 10% threshold based on its proposed approach in its

[160] CEPA (May 2020), 'RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper', section 4.4.2

June 2019 report. However, its June 2019 report does not actually propose any materiality threshold, and instead indicates that there is no clear "hard-and-fast" rule to setting one. It is not clear when and why its position on the materiality threshold changed. We appreciate the desire for simplicity and proportionality in designing the RPE index, which can be achieved by reducing the number of cost areas subject to indexation, however the approach must result in indexation that is a sensible proxy for SPT's exposure to inflation. Ofgem are setting out a materiality threshold for plant and equipment without explaining how they have evidenced this, for example, Ofgem have applied an RPE for one cost area (Plant & Equipment) for one TO (SHET), while not applying it to others. In the remainder of the response to this question, we consider whether Ofgem's chosen indices and its proposed approaches to weighting them together are likely to reflect actual fluctuations in efficient input costs. We find that they are unlikely to do so.

<u>Labour RPE</u>

4.21 Ofgem bases the Labour RPE on five indices which it used at RIIO-T1, providing no explanation as to how they satisfy the assessment criteria and without assessing any alternatives. These five indices show substantially different long-term growth rates from each other, but Ofgem combines them into a single Labour RPE using an unweighted average, implying that each series represents 20% of our labour costs, but without specifically justifying that implication. Ofgem has therefore not undertaken a robust process when assessing whether or not the specific indices or the overall Labour RPE accurately reflect the changes in TOs' labour costs. This is a necessary assessment to undertake to assess the risk that the new indexation approach over or under compensates TOs for changes in the market cost of labour during the T2 control period.

4.22 More specifically, it is not clear how some of the indices satisfied the stated assessment criteria. For example, one such index is the ONS AWE Transport & Storage series. Trends in wages for transport/storage labour are, at best, equally important, or most likely, far less relevant to us as those in electrical engineering wages. More weight should be placed on indices related to the latter

4.23 Additionally, while the indices are relatively stable over time up to 2019, some have shown a sharp downturn as a result of the COVID-19 pandemic. In practice, these indices have declined because of a reduction in average weekly working hours, driven especially by furloughs. Transmission companies are essential businesses, we continued to need our staff and we are therefore not able to furlough our staff at the same rates that are reflected in the economy-wide data. There is no evidence that average hourly wages have declined.

4.24 For as long as the dip in economy-wide wage indices persists into (or returns during) RIIO-T2, transmission companies will be unduly penalised for labour cost reductions associated with the economy-wide furlough scheme that they themselves did not participate in. This penalty will be "erased" once wages return to where they would have been in the absence of the pandemic, i.e. because hours worked increase again, but it will cause unnecessary fluctuations in cash flows to companies and charges to customers.

<u>Materials RPE</u>

4.25 Ofgem bases the Materials RPE for SPT using two indices: The BCIS FOCOS index reflects opex materials and receives 35% weight; The BCIS PAFI Copper Pipes index reflects capex materials and receives 65% weight. The weightings have been derived from our reported cost structures, and so we do not raise concerns with them beyond stating that any weightings should reflect post cost-assessment cost structures.

4.26 However, it is not at all clear that the selected indices themselves are appropriate for indexation, especially since CEPA does not consider any alternatives and does not explain how each series matches each criterion. In particular, it is not possible to understand why our capex materials costs are indexed to the price of copper pipes, a material input which does not feature prominently in our capital expenditure. Several other BCIS PAFI indices appear to be more relevant to the nature of our work, such as those relating to electrical cables, electrical engineering materials, and electrical installations. We have limited confidence in Ofgem's approach knowing that CEPA did not appraise these indices. It points to the arbitrariness of CEPA's selection process.

4.27 The indices that Ofgem rely on are themselves composed of Producer Price Indices (PPI) produced by the ONS. PPIs are divided into Input PPIs (which measure the price of goods bought by UK manufacturers) and Output PPIs (which measure the prices of goods sold by UK manufacturers). It is not clear to what extent the selected indices are driven by Output rather than Input PPIs, but insofar as they are (i.e. Output PPIs), they capture the wider effects of productivity in the UK economy. This is a relevant fact to our response to Q11 below, in which we discuss the share of costs on which an ongoing efficiency challenge could be applied.

Other categories

4.28 With the exception of Plant & Equipment for SHET, Ofgem finds that all other cost categories are immaterial for all other companies.

4.29 As stated above, CEPA's materiality threshold is arbitrary, unjustified and unnecessary. If Ofgem is willing to carry out the additional work necessary to apply a Plant & Equipment RPE to SHET, it would add little if any complexity to apply it to all companies. Indeed, it would reduce complexity as Ofgem would no longer need to calculate separate RPE indices for all transmission companies. If Ofgem are to maintain their approach to assessing materiality, they should re-assess materiality based on allowed costs instead of business plan submissions, as this is the measure that will actually determines companies' totex over the RIIO-T2 period.

4.30 Additionally, for costs which do not have an RPE, Ofgem should have regard to the change in inflation indexation from RPI to CPIH. Ofgem estimates that the RPI-CPIH wedge is about 1.05%, of which CEPA estimates up to 0.7% is due to a "formula effect" in how the RPI average is calculated. Even if RPI is "wrong" due to the formula effect, there remains at least a 0.35% wedge between them which is otherwise unexplained. By indexing the price control to CPIH rather than RPI, Ofgem assumes that the remaining cost categories will grow at a slower rate than during RIIO-T1.

Conclusion

4.31 The introduction of an indexation approach to RPEs will introduce new risks to transmission companies' revenue allowances, which will ultimately harm customers. Our experience has shown that the relevant indices do not track the short-term movements in network companies' input costs, they are instead better used for observing the long-term input inflationary pressures that companies face. Ofgem has not carried out a rigorous assessment of the relevance of these indices, or, if it has, it has not provided more than a few high-level statements on its process. It is therefore impossible to be confident that Ofgem's selected indices for indexation actually track changes in companies' efficient input costs.

4.32 With a period of high macroeconomic uncertainty due to COVID-19 and Brexit, it is a near certainty that shocks to the selected indices will likely be higher than they have been in the past. According to Ofgem's proposal, network companies will now be exposed to these shocks for the first time. In practice, these macroeconomic shocks should have offsetting effects on input price pressure and productivity improvement, at least partially insulating companies from the full shock on either component individually. Ofgem's approach to indexing only RPEs and not ongoing efficiency will remove this offsetting effect.

4.33 Given the uncertain outlook for the cost indices due to the effects of COVID-19 and the possibility of a detrimental future trading arrangement with the EU, we strongly believe that could reduce revenue risks (and costs associated with those risks) by returning to its previous practice of setting an ex ante RPE allowance. When setting the frontier shift for RIIO-2, Ofgem should adopt a prudent approach whereby productivity and RPEs are assumed to offset each other across the price control period, and the price control should instead be solely indexed to CPIH. The approach would allow companies to hedge their risk exposure to changes in input costs and would avoid volatility in revenues and customer bills.

Q11. Do you agree with our proposed ongoing efficiency challenge and its scope?

4.1 We have material concerns with Ofgem's use and interpretation of evidence in this area, and as a result we do not agree with Ofgem's proposed ongoing efficiency challenge and its scope. Ofgem has selected the upper bound of CEPA's range when setting the ongoing efficiency challenge for RIIO-2, resulting in productivity targets that are higher than previously applied in any recent comparable GB regulatory decisions. Of significant concern, is that Ofgem proposes an additional efficiency stretch of 1.2% per year for CAPEX and 1.4% per year for OPEX, which translates to £62m based on the Draft Determination TOTEX value. This does not, however, take into account cost efficiencies which we have already embedded into our Business Plan submission. An efficiency stretch totalling £145m was applied to our baseline plan by SPT. This comprised known efficiencies delivered through our innovation in design, increased utilisation of existing assets and other productivity improvements delivered over the course of T1 (£110m). A further 2.5% (£35m) efficiency stretch was incorporated in the RIIO-T2 baseline plan of £1375m. There is therefore a double count.

4.2 This decision has been made based on Ofgem's incorrect assumption that the over decade-long period of near-zero productivity growth is but a temporary 'anomaly' and has not affected network companies. The evidence is clear that there has been a demonstrable step change in productivity growth across the UK economy since the global financial crisis in 2008, and the latest forward-looking forecasts suggest that the trend of low productivity growth is likely to continue.[161] Network companies are not immune to this slowdown in productivity growth, and as such the forward-looking estimate of productivity improvement set by Ofgem should consider this apparent structural change in productivity.

4.3 Ofgem have not addressed this "productivity puzzle" and its continuation into the RIIO-T2 period and beyond, further compounded from the economic disruption caused by COVID-19 and the subsequent recession, in its assessment. Put simply, Ofgem's overestimated productivity improvement targets cannot credibly be achieved by regulated network companies over the RIIO-T2 period. In any case, Ofgem has effectively created a double count of ongoing efficiencies by not recognising the efficiencies SPT has already embedded within its Business Plan.

<u>CEPA ignores shorter-term dynamics in productivity growth</u>

4.4 When analysing the 2019 EU KLEMS dataset, CEPA have erroneously observed data from 1997 to 2016 – the longest period possible that includes only complete business cycles. Using long-term average of these productivity indices represents the "best guess" when setting allowances, as it captures the long-run effects of technological progress and improved working practices. However, this approach is only appropriate if we believe that the forward-looking period is not fundamentally different from the historical period analysed. This however is clearly not the case. Ever since the Global Financial Crisis in 2008, the nature of the UK economy has changed such that expected productivity growth in the future is no longer consistent with long-term trends. This can be observed from the analysis by the OBR which shows that annual growth in output per worker (i.e. labour productivity) averaged around 0.3% per annum between 2008 and 2018, compared to 2.3% between 1990 and 2007 and markedly below the long-term average trend.

4.5 CEPA has not applied appropriate analytical judgement when selecting the 1997-2016 data window. It includes productivity statistics which are composite of the pre-2008 business cycle, 2008-10 recession/recovery and the subsequent post-crisis economy, with an obvious "structural break" in the middle. CEPA has attempted to argue that this "structural break" in the economy with a period of near stagnant productivity growth is an anomaly, and that productivity will revert back to its long-term average during the RIIO-2 period, citing recent forecasts from the OBR and the Bank of England (BoE) on labour productivity growth of 1.15% and 1.0% on average during the years of the RIIO-T2 control, respectively.

4.6 However, as NERA point out[162], the forecasts used by CEPA to corroborate their proposition are not reliable if they do not capture the existence of or reasons for a structural break in productivity growth. With the OBR, their approach is to set a "steady state" productivity level and a horizon over which productivity will return to that level. If the assumptions around this steady state level are not robust, then the OBR's forecasts

[161] First Economics (August 2020), 'Frontier Productivity Growth', a report prepared for the ENA, section 2
[162] NERA (September 2020), 'Frontier Shift at RIIO-T2 Draft Determinations', section 2.2.2

of productivity over the RIIO-T2 period are also not robust. Indeed, issues with OBR's historical forecasts are observable, as over the past few years the OBR has repeatedly revised its forecasts downwards to reflect the weak outturn productivity exhibited in the UK.

4.7 Even though the OBR and BoE forecasts have only recently been released, they are already outdated given that both publications pre-date the onset of the COVID-19 crisis and therefore have not factored in the unprecedented negative impact that this pandemic will have on the UK economy in the medium to long-term, with the economic disruption anticipated to constrain and reduce productivity growth, with long-lasting "scarring" to the economy as a result. The BoE published their August 2020 Monetary Policy Report, which includes updated – and lower – productivity forecasts than the ones published in the January 2020 edition which CEPA reference in their report. BoE now forecast a 0.75% growth in both 2021 and 2022 (and 0.75% on average during RIIO-T2). It appears now that the BoE no longer corroborate the 1.1% "reference value" that CEPA estimates. There is therefore a risk that regulatory decisions, based on pre-crisis assumptions, are 'baked in' to the RIIO-T2 price control framework, which do not take account of the fundamental impact of the crisis on the wider economy and society.

4.8 Additionally, both the OBR and BoE labour productivity measures are calculated as GDP or output divided by total hours worked, and do not hold capital constant. If the OBR and BoE assume that capital stock will grow in their short-term forecasts (as has been the case in every year since 2010), then some of the forecast gains will come from a growth in the amount of capital used per worker. These estimates will therefore be higher than those which hold capital constant, as CEPA does in its labour productivity estimate. The BoE estimate is therefore not directly comparable to the measure of productivity CEPA seeks to estimate, and in fact likely overstates it.

4.9 It is incorrect to think of the over decade-long period of near-zero productivity growth as a short-term issue or a temporary 'anomaly'. There is clear and incontrovertible evidence that there has been a demonstrable step change in productivity growth across the UK economy since the global financial crisis, and the latest forward-looking forecasts suggest that the trend of low productivity growth is likely to continue, with the structural break persisting into the RIIO-T2 period and beyond due to the implications of COVID-19 and the subsequent recession. Using a long-time series of TFP growth will likely overstate productivity growth. As such, the long-term productivity trend should only be estimated as of the structural break. CEPA should therefore place more weight on their shorter-term (2006-2016) averages. CEPA should also acknowledge the above hypothesis placing weight on the lower point estimate from their existing range.

CEPA misrepresents the choice between VA and GO productivity measures

4.10 CEPA analyses Total Factor Productivity (TFP) and labour productivity (LP) measures based on both Value Added (VA) definitions, which isolates the ease with which a firm is able to transform intermediate inputs into a finished product or service, and Gross Output (GO) definitions, tracks the way in which a final output is produced out of all controllable costs[163]. GO definitions are by definition lower than VA.

4.11 Although they state the choice between the two measures is not clear cut, CEPA presents its VA values as its central estimate and GO as its "downside" sensitivity. This choice is arbitrary and incorrect. While regulators have placed some weight on VA measures for practical purposes, past regulatory decisions[164] have consistently concluded that GO measures are the more appropriate to measuring potential for efficiency improvement for regulated companies based on economic theory, albeit with practical challenges to implementation. Ofgem should therefore acknowledge this tendency in the long-standing debate between the two measures and place favour on estimates from GO TFP measures rather than VA measures, or at the very least equal importance, when setting ongoing productivity targets.

4.12 CEPA's recommend use of VA to Ofgem results in them incorrectly challenging networks to deliver this rate of productivity growth across the whole of their totex. As stated by First Economics, if Ofgem wishes to use value-added productivity growth metrics it needs to isolate the value-added within energy network

[163] CEPA states that it is "good regulatory practice to consider the information provided by both methods when developing a range for ongoing efficiency estimates" see: CEPA (27 May 2020), RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper, p.12.
[164] See: NERA (September 2020), 'Frontier Shift at RIIO-T2 Draft Determinations', section 2.3.1

companies' expenditures and provide for future cost savings only in this portion of firms' costs.[165] They have not done so. Productivity growth in GO terms needs to be referenced if applying the efficiency challenge across the whole controllable totex.

CEPA presents only a selective "lower bound" view

4.13 In presenting their lower bound GO estimate of 0.5% for both TFP and LP, CEPA have arbitrarily only considered its "wide" definition of comparator sectors (weighted average of all sectors, excluding real estate, public administration, education, health and social services). For reasons not provided by CEPA, they exclude the "narrow" industry definition in their estimation of the lower bound GO value (construction; wholesale and retail trade; repair of motor vehicles and motorcycles; transportation and storage; financial and insurance activities). This decision is arbitrary and inconsistent with the approach taken when measuring VA measures where they deem the "narrow" definition to be a relevant consideration. Applying a consistent methodology to GO measures would produce productivity values of 0.3% for TFP and 0.4% for LP for CEPA's lower bound, lower than their original selective lower bound value.

There is no basis for an innovation funding adjustment

4.14 CEPA estimates an additional efficiency challenge of up to 0.2% to ensure that customers earn a reasonable return on upfront costs of the RIIO-T1 innovation funding.[166] However, this calculation does not seek to measure what an efficient company can actually achieve as a result of the RIIO-T1 innovation funding, which is what the frontier shift should do. CEPA's approach to determining the innovation funding adjustment has no basis in the additional cost reductions an efficient company could reasonably achieve during RIIO-T2. Instead, the target takes what CEPA deems to be a fair return to customers (4.2%), and "goal seeks" an arbitrary set of *input* assumptions that yield that result, including the cost reduction profile during RIIO-T2.

4.15 Innovation projects are not justified solely on grounds of anticipated cost reduction, it is but one objective of the projects funded through the RIIO-T1 innovation allowances. In fact, much of the funding is largely targeted towards other objectives, such as environmental outputs, safety quality of service and the energy transition[167]. Of the £88.5 million in NIC funding awarded to transmission companies during RIIO-T1, less than £10 million was directed to projects which were primarily focused on cost reductions that are remunerated via the TOs' price controls. A further £36.2 million was directed to projects where cost reductions are an ancillary benefit to the project. If such R&D investments were profitable enough purely from a cost perspective to earn a return throughout RIIO-T2 through cost savings, then they would have been made without the need for a separate innovation funding allowance. It is therefore unreasonable for CEPA to assume that customer-funded innovation should be as profitable in terms of the resulting cost savings as investor-funded innovation.

4.16 Although CEPA highlight the importance of identifying the level of innovation benefits already embedded in business plans, they have not done so in their assessment of the adjustment. This potential double count consideration was at issue in Northern Powergrid (NPg)'s successful appeal of RIIO-ED1 to the Competition and Markets Authority (CMA), where the CMA concluded that Ofgem had failed to establish that Smart Grid Benefits (SGBs) were not already accounted for through the general cost benchmarking exercise.[168] CEPA incorrectly assumes that "no additional ongoing efficiency driven by innovation funding in RIIO-T1 is already embedded in the baseline spending plans submitted by the companies" due to the absence of firm, quantitative evidence."[169] Although it may be difficult to precisely quantify the effects of RIIO-T1 innovation funding on business plan cost forecasts, it does not mean that no such relationship exists. It is difficult to separate whether cost reductions have resulted from Ofgem-funded innovation projects, improvements in technology that have occurred for other reasons, or from other improvements in

[165] First Economics (August 2020), 'Frontier Productivity Growth', section 3.1
[166] CEPA (May 2020), RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper, p.26
[167] See table 2.2 in NERA's report which lists all transmission projects which were awarded NIC funding during RIIO-1, along with a brief description of their stated objectives and an assessment of the extent to which those objectives related to reductions in costs covered by the RIIO revenue controls.
[168] CEPA (May 2020), RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper, p.28.
[169] CEPA (May 2020), RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper, p.26.

working practices achieved by the TOs. Indeed, within our RIIO-T2 Business Plan we set an embedded efficiency stretch on the basis of, 'innovation, value engineering & process changes'.

4.17 Additionally, R&D expenditure takes place in competitive markets, as competitive firms must innovate to remain competitive. These firms (and their R&D) contribute to the TFP growth measured in the EU KLEMS dataset. Regulated, non-competitive firms do not face the same pressure, with historical productivity improvements coming as a result of post-privatisation restructurings rather than R&D (effectively catch-up efficiency, with diminishing returns). Even with the dedicated RIIO-1 allowances, transmission companies' R&D budgets were smaller as a proportion of total expenditure than aggregate R&D is as a proportion of GDP. Simply put, by providing companies with innovation funding (through a competitive process), Ofgem simply brought companies more in line with their competitive counterparts, and separately accounting for cost savings due to innovation double counts the cost savings already embedded in the TFP estimates. There is therefore no reason to believe that transmission companies can achieve faster productivity growth than the economy as a whole simply because of their RIIO-T1 R&D allowances.

Ofgem's use of the CEPA Report

4.18 In relevant past regulatory decisions, UK regulators have tended to set ongoing efficiency challenges based on the approximate midpoint of the range of possible levels.[170] When presented with CEPA's estimate productivity range, along with their caveats and points for Ofgem to consider when setting their productivity target for RIIO-T2, Ofgem have departed from precedent, choosing to ignore the caveats outlined by CEPA[171] and set their ongoing efficiency challenge purely based on the upper bound of CEPA's range. In doing so, Ofgem have effectively placed all weight on estimates which have been derived from assumptions which are not justifiable for the reasons we have set out above (i.e. VA measures, time period analysed, wide industry definition and the full 0.2% innovation benefit).

4.19 Rather than take a robust and fair assessment of the available evidence presented to them, Ofgem's decision appears to reveal their objective of setting an unrealistic ongoing efficiency target for transmission companies, exaggerating the scope of productivity improvement that transmission companies are assumed to be able to achieve over the RIIO-T2 period. In line with regulatory precedent, we argue that Ofgem should take a more balanced assessment of the available evidence on productivity and select a productivity estimate from the middle of a more balanced and plausible range of estimates.

4.20 Ofgem also fails to account for the level of ongoing efficiency which is embedded into companies' business plans, and which drives components of the cost assessment process. As described by NERA, Ofgem has not adjusted for the embedded efficiency within companies' historic costs in its assessment of NOC and indirect cost allowances for RIIO-T2[172]. An efficiency stretch totalling £145m was applied to our baseline plan. This comprised of known efficiencies delivered through our innovation in design, increased utilisation of existing assets and other productivity improvements delivered over the course of T1 (£110m). A further 2.3% (£35m) efficiency stretch was incorporated in the RIIO-T2 baseline plan of £1375m. In order to maintain consistency between the cost assessment and frontier shift elements of the price control, Ofgem should strip out the embedded productivity *before* comparing RIIO-1 and RIIO-2 costs. Only after setting these allowances should Ofgem apply an ongoing efficiency adjustment, whether that is based on its own view or companies' views of the scope for ongoing efficiency.

[170] See: Ofgem (17 December 2012), RIIO-T1/GD1: Real price effects and ongoing efficiency appendix, para. 3.3 and Competition Commission (26 March 2014), Northern Ireland Electricity Limited price determination, para. 11.27

[171] For example, with respect to the use of GO or VA measures, CEPA *"suggest that Ofgem should focus on considering the case for […] giving some weight to GO measures in EU KLEMS. […]"*. Ofgem states that *"we believe that the practical difficulties in estimating GO limit the weight that can be reasonably placed on them (compared to VA measures). We therefore do not think it is appropriate to give any weight to GO measures."*[171] This ignores the fact that companies purchase intermediate inputs rather than just raw inputs, making a GO approach more appropriate.

On innovation benefits, CEPA state that *"deciding how this 0.2% figure should be reflected […] will be based on judgement on […] the importance of benefits to consumers other than cost savings – such as environmental benefits and quality of service."*[171]. Ofgem considers whether some benefits may relate to non-cost improvements, but *"believe[s] that there are sufficient levels of gains that are likely to come from lower costs that this should be accounted for, and this should result in them achieving at least 0.2% additional ongoing efficiency"*. Ofgem does not explain or justify this belief.

[172] NERA (September 2020), 'Frontier Shift at RIIO-T2 Draft Determinations', section 2.6.5

Conclusion

4.21 After correcting the methodological departures from regulatory precedent and economic theory outlined in the above text, NERA offer an alternative figure for productivity improvement that consider a more balanced range of methodological choices across these parameters, using only figures presented in the CEPA report i.e. place equal weight on VA and GO measures of productivity growth, and include both the "wide" and "narrow" industry definitions in calculating GO productivity growth; place equal weight on the longer data series (1997-2016) and the post-crisis series (2006-2016); assume that the cost-related benefits of RIIO-1 innovation funding (insofar as they exist) are already captured in the EU KLEMS dataset and companies' business plans, and do not apply an uplift for innovation funding; and take an unweighted average across all estimates, rather than selecting the upper bound.

4.22 NERA's recommended figures are presented in Table 6 below, which suggest an efficiency target of 0.3% for all cost categories - far below Ofgem's estimates. Using the same evidence but assessed in a different way leads to the opposite conclusion that Ofgem have taken.

Table 6 – NERA's Alternative Ongoing Efficiency Estimates

	TFP (Capex/Repex)		LP (Opex)	
	1997-2016	**2006-2016**	**1997-2016**	**2006-2016**
Narrow (GO)	0.3%	-0.1%	0.4%	-0.2%
Wide (GO)	0.5%	0.1%	0.5%	0.1%
Narrow (VA)	0.6%	-0.3%	1.0%	-0.6%
Wide (VA)	1.0%	0.2%	1.2%	-0.2%
Average by Window	0.6%	0.0%	0.8%	-0.2%
Average	**0.3%**		**0.3%**	

Source: CEPA Tables 2.2 and 2.3
Note: Narrow = Unweighted average of selected industries (exc. manufacturing); Wide = Weighted average all industries (exc. real estate, etc).

Source: NERA, 2020, 'Frontier Shift at RIIO-T2 Draft Determinations', Table 1

4.23 Additionally, as set out in our response to Q10 above, the Materials RPE indices appear to capture underlying trends in productivity. As we outsource much of our direct capex, there is little scope to improve our productivity in capex above and beyond the work we procure externally, whose productivity gains are already captured in the Materials RPE. Our ability to deliver efficiency improvements is considerably dependent on the ability of our contractors to deliver efficiencies. Ofgem cannot dismiss the wider macroeconomic "scarring" impact that COVID-19 and the recession will have on innovation and productivity growth throughout the industry supply chain. To the extent that these contractor firms are struggling with productivity, we will also find it more difficult to achieve productivity improvements at levels seen in the past.

4.24 When recommending an appropriate ongoing efficiency for RIIO-2, we note that the consideration needs to acknowledge the UK economy's failure to revert to pre-2008 rates of productivity growth, and likely continuation further exacerbated by the impacts from COVID-19 and the recession, as seen in the BoE forecasts. It is clear that the data on productivity growth points down rather than above the frontier productivity targets set by Ofgem.

4.25 When assessed against the available data on productivity improvement and in light of the uncertain outlook for the cost indices, a prudent solution would be to assume that that RPEs and ongoing efficiency will offset each other across the price control period, and the price control should instead be solely indexed to CPIH. This position is consistent with that which we outlined in our RIIO-T2 Business Plan submission. Ofgem should adopt this pragmatic and simple approach for setting the frontier shift for RIIO-T2 given the current economic climate.

4.26 Most importantly, Ofgem must address the issue of a double count as previously mentioned. A company cannot be expected to deliver an ongoing efficiency when it has already embedded these efficiencies within its Business Plan costs.

4.27 Our positions are supported in more depth in Chapter 2 of NERA's report on Frontier Shift.[173]

[173] NERA (September 2020), 'Frontier Shift at RIIO-T2 Draft Determinations'

Chapter 5: Uncertainty Mechanisms

Introduction

5.1 The GB electricity transmission network has a fundamental role to play in achieving the Scottish Government's objectives for Net Zero by 2045 and the UK Government's objectives for Net Zero by 2050. When the UK and Scottish governments announced their Net Zero legislation in 2019, development of our business plan was very advanced, with the first draft being completed but was well positioned to deliver this. SPT's RIIO-T2 Business Plan incorporated activity with a high confidence baseline and a robust suite of uncertainty mechanisms that provided the flexibility for the Business Plan to evolve as the wider energy landscape changes and government policies develop. This strategy aligned with the Scottish Government's evolving ambition and the wider work of the Committee on Climate Change on the pathway to Net Zero.

5.2 This strategy also aligned with our understanding that Ofgem would support the requisite steps to transition to Net Zero. Indeed, Ofgem explicitly stated in the Sector Specific Methodology Decision that *"One of the overriding objectives of the RIIO-ET2 framework is that network companies make a full contribution to the low carbon transition."*[174] Ofgem's statutory duties include the need to address the interests of present and future consumers in the reduction of electricity related emissions of greenhouse gas, and the need to contribute to sustainable development. However, Ofgem's Draft Determination does not deliver the ambition needed to achieve Net Zero and Ofgem's approach is inconsistent with its environment-related objectives and duties.

5.3 As we write this response, we are reflecting on the announced closure of Hunterston Nuclear Power Station and the implications for the wider aging fleet across our country that will require an ability for Electricity Transmission Networks to have the headroom to cope with large uncertainty and maintain high levels of security of supply. This only demonstrates the rapid changes that our electricity transmission network needs to respond to and the need for innovative solutions as outlined in our Business Plan such as Synchronous Compensation as well as conventional reinforcement of the system as a whole.

5.4 Business plans and uncertainty mechanisms need to account for the known and unknown uncertainties that lie ahead. To do this, they require: the flexibility to cater for a wide range of outcomes; the ability to be changed at a pace that matches customers' requirements; and adequate coverage over costs that companies would efficiently incur. SPT carefully and rigorously prepared a package of investments in our Totex plan, which was challenged extensively by stakeholders and justified with robust evidence. For projects with less certainty, we proposed a range of uncertainty mechanisms in our Business Plan, with detailed justifications, and extensive stakeholder support. Ofgem have rejected some of these proposals without giving clear reasons, substituting its own uncertainty mechanisms. These mechanisms are poorly designed and will likely materially delay projects that are critical to the achievement of Net Zero. As a result, the correct balance has not been struck in this area.

5.5 Ofgem acknowledges that price reviews need to become more agile. We agree with this – which is why we developed our Business Plan in the way described above with a focus on uncertainty mechanisms. The impact of Ofgem's approach on companies, and the financial uncertainties it creates, has not been adequately reflected in the finance package proposed. The potential investment requirements are likely to be substantially higher than the baseline plan. Companies also face uncertainty as to when this investment requirement will materialise, along with the higher risk that the activity will have a bearing on incentive performance. Ofgem's Draft Determination rejects two of SPT's Totex proposals that are of sufficient certainty to require delivery and places some other elements into poorly designed uncertainty mechanisms which will significantly delay and hamper the sector's ability to contribute to Net Zero, as detailed in the Totex chapter and this chapter.

5.6 We were disappointed that after positive engagement with Ofgem, Ofgem has, in its Draft Determination, proposed new mechanisms which are different than what we, or any TO, had submitted with their Business Plans with no real clarity or justification as to why the mechanisms submitted by the TOs have

[174] *"RIIO-2 Sector Specific Methodology Decision - Electricity Transmission"*, Ofgem, 24 May 2019, Paragraph 3.104

been discounted. There should be a clear methodology or process applied to compare TO proposals with Ofgem's and explain the change in approach.

5.7 Discussions on Ofgem's new proposals are therefore now at an early stage. We have concerns over the overall timescales for developing these so that they are workable and ready for licence drafting, which is currently ongoing, and the beginning of the RIIO-T2 period.

5.8 During the RIIO-T2 price control period, due to Ofgem's approach of requesting companies to provide a high confidence baseline, there will be substantially more work than ever before being funded via uncertainty mechanisms. The scope and nature of these projects remains largely unknown. Therefore, it is of paramount importance that any mechanism proposed is workable, efficient and unambiguous so as to provide SPT with the confidence to invest the necessary time and resource in developing schemes subject to these mechanisms.

5.9 We note a greater use by Ofgem of reopeners and ex-post adjustments proposed in the RIIO-T2 period. This is an approach that will likely slow down project development and hinder investment due to increased regulatory burden. This is of particular relevance to the many areas with a proposed January 2024 submission window such as outlier generation connection schemes and "externally driven works". This approach places unacceptable risk on SPT developing any scheme until this point and, combined with lower returns, does not provide companies with any incentive to progress with projects at risk until a regulatory decision is made.

5.10 In our Issues Log, a copy of which is enclosed in Annex 2, we have raised over 20 issues with Ofgem on areas relating to Uncertainty Mechanisms with recurring themes across several mechanisms including:

- Lack of clarity/methodology for Ofgem's proposals,
- Errors from Ofgem's Project Assessment Model impacting uncertainty mechanism areas, and
- Modelling Errors.

5.11 We require the issues detailed in our Issues Log to be resolved in order for these mechanisms to be fully developed before we can fully review the Final Determination.

5.12 Below is a review of uncertainty mechanisms proposed by Ofgem that are not be captured by any specific consultation question from the Draft Determination.

Generation and Demand Connections

5.13 As the TO for central and southern Scotland, SPT has a licence obligation to facilitate the connection of generation to the transmission network in our geographic area. Our system is crucial to the delivery of the UK and Scottish Government's renewable energy and Net Zero objectives due to its location in an area of outstanding renewable resource and our network providing an energy corridor within the GB transmission system. The current approach and remuneration of Ofgem's Generation and Demand Connections uncertainty mechanism is of major concern as it does not adequately address the costs that we would be required to incur for this activity. No questions in the Draft Determination consult on this aspect therefore we have set out our views below.

5.14 Over the RIIO-T2 price review period, we are contracted to connect over 5000MW of renewable generation, 4000MW more than our baseline plan, which would make an annual saving of more than 3 million tonnes of CO_2 per annum. Since the publication of our Business Plan in December 2019, we are now contracted to connect a further 1000MW of generation, illustrating how quickly the market can move.

5.15 We only included expenditure proposals in our Business Plan for projects which we had a high confidence would materialise in RIIO-T2. To ensure that currently less certain projects could progress without undue delay, we proposed several uncertainty mechanisms to provide allowances when such projects became more certain. This approach was supported by stakeholders and our User Group.

5.16 During the development of our Business Plan, we engaged with Ofgem on numerous occasions about the design of our proposed mechanisms. Despite this positive engagement, Ofgem has proposed different mechanisms with no clarity as to why our proposals were dismissed.

5.17 In the Draft Determination, Ofgem has proposed using a consistent approach across all TOs in the level of disaggregation that they have applied to the volume driver but providing rates for different activities specific to each company to reflect the different connections and network challenges that each TO has. Whilst, at a high level, this is a fair approach, there are major differences between what SPT, SHET and NGET proposed in December 2019 and Ofgem's Draft Determination and it remains unclear why the TOs' approaches were rejected and how Ofgem assessed the associated merits and drawbacks of each approach. A common approach still needs to account for the varied challenges facing each TO, reflecting cost drivers relating to the range of solutions that may be deployed. The deployment of a range of engineering solutions is in the best interests of, and represents best value for money to, existing and future consumers.

5.18 The over-simplification of such solutions through creation of a single unit rate is not justified and devalues what, otherwise, would be a workable and enduring volume driver. It is unclear how Ofgem assessed the merits and drawbacks of our proposals compared to their own. SPT will be underfunded by £90m if we are to connect the additional 4000MW of generation and associated reinforcement through the proposed mechanism as detailed in the Draft Determination.

5.19 The uncertainty mechanism (**UM**) model to inform the calculation of the volume driver allowance for this mechanism was not made available until the 27th of July 2020, three weeks after publication of the initial Draft Determination documents, leaving even more limited time to assess this very complex model. No methodology has been provided by Ofgem alongside the UM model. We have raised several issues with Ofgem in our Issues Log regarding the data used in modelling. An example of this is issue UM-019, which identified missing cost data for all uncertain schemes. Additionally, we have identified significant errors in the model which have clearly distorted results such as customer and infrastructure costs (as defined in the CUSC) combining for total cost analysis even though rates only fund infrastructure costs and are therefore materially different (UM-015). Ofgem provided an updated model on 17 August 2020; however, several data issues still remain. There also appears to have been limited assurance performed of the model data. The results appear not to have not been subjected to basic validation checks.

5.20 We acknowledge that the disaggregated approach can provide greater cost reflectivity, as our modelling showed in Annex 20, Uncertainty Mechanisms (submitted as part of SPT's December Business Plan). However, the output of the linear regression analysis that Ofgem has used to derive their "unit rates" for substation, overhead line and cable assets bears no resemblance to a "real world" cost for physical assets that we require to build. Fundamentally this is what it should seek to do. A volume driver should be efficient, cost reflective and statistically sound. It is our opinion that Ofgem's proposed volume driver achieves none of these criteria.

5.21 For example, as we connect greater amounts of generation on to the network, facilitating the push to reach UK and Scottish Government Net Zero Targets, there is a need to create more capacity on our overhead line circuits. The range of solutions could include re-conductoring which would have a unit rate of c.£210k per cct km or the construction of a completely new wood pole line c.£613k [per cct km] but will depend on each situation. The proposed rate of £53k does not align with any of these situations. It is significantly below the costs SPT would incur in meeting its legal obligations.

5.22 The data set that Ofgem have relied on is not statistically robust, and the assumptions are flawed. From the December Business Plan and supplementary questions, we have provided Ofgem with 60 schemes, each with associated costs and volumes that can be used to inform the statistical analysis and the volume driver rates. From the Ofgem UM model, populated with Ofgem's views of SPT's costs from their Project Assessment Model (PAM), it would appear that only a small subset of these schemes has been used to define any volume driver rates, which does not provide sufficient statistical relevance. Regression analysis cannot be adequately performed on such a small sample size. All relevant data, minus clear outliers, should be used in any analysis to ensure any volume driver is reflective of the schemes it will be used to fund. This is the approach SPT adopted to identify the proposed volume driver and associated rates. A larger sample size increases confidence that volume driver rates will be fit for purposes and able to efficiently fund the majority of schemes.

Analysis – Total project cost

5.23 We are currently contracted to connect close to 40 projects that are uncertain, i.e. we did not have sufficient confidence that these projects will go ahead to include them in our baseline. A good volume driver will accurately predict the total project cost, regardless of which combination of projects proceeds. We have used a Monte Carlo Analysis approach to assess the performance of our proposed volume driver against Ofgem's[175]. This analysis randomly picks combinations of projects that will go ahead, assuming that all projects are equally likely to proceed. We then calculate if the volume driver provides insufficient or excessive funding. This process is then repeated many times (5000 times, in this case) to assess the performance of the driver against a wide range of possible future outcomes.

5.24 The results are given in Figure 6. and show how often the mechanism provides insufficient (negative number) or additional funding (positive number) and how large the funding error is. The horizontal axis shows the funding error in £k. A very accurate volume driver would lead to all outcomes being clustered around zero, with very few cases with significant cost errors. A poor driver leads to a wider spread in the results, i.e. there is a high probability that the costs will be significantly under- or overestimated in most future outcomes.

5.25 In Figure 6. the results using the SPT proposed volume driver are shown in blue and the results using Ofgem's driver are shown in red. The SPT driver has a high probability of predicting the total cost accurately as shown by the large number of cases clustered around the zero-error point. There are few cases where the cost error is higher than £10m. By contrast, the Ofgem results are widely spread and significantly under-estimate the cost in almost all cases. As SPT would be almost certain to over-spend significantly, relative to the Ofgem cost driver, this presents an unacceptable risk and places SPT in a position where it is not adequately funded for an activity that it is obliged to carry out. Ofgem have disaggregated project variables (substation, overhead line and cable outputs) yet the wide spread of results suggests this has not led to the desired levels of accuracy. We believe that accuracy could be increased by moving to a greater level of disaggregation, such as a separate reconductoring rate for overhead lines, and have shown this in our analysis below. SPT has provided Ofgem with suitable data[176], to be able to split out these types of schemes within their model. This would allow any analysis to have greater detail and derive cost reflective rates.

5.26 The lack of accuracy in Ofgem's proposal can be illustrated further by considering the extreme case where all contracted projects go ahead. In that situation, the Ofgem driver would lead to SPT not being able to recover £90m in costs if we were to use Ofgem's original proposed volume driver rates.

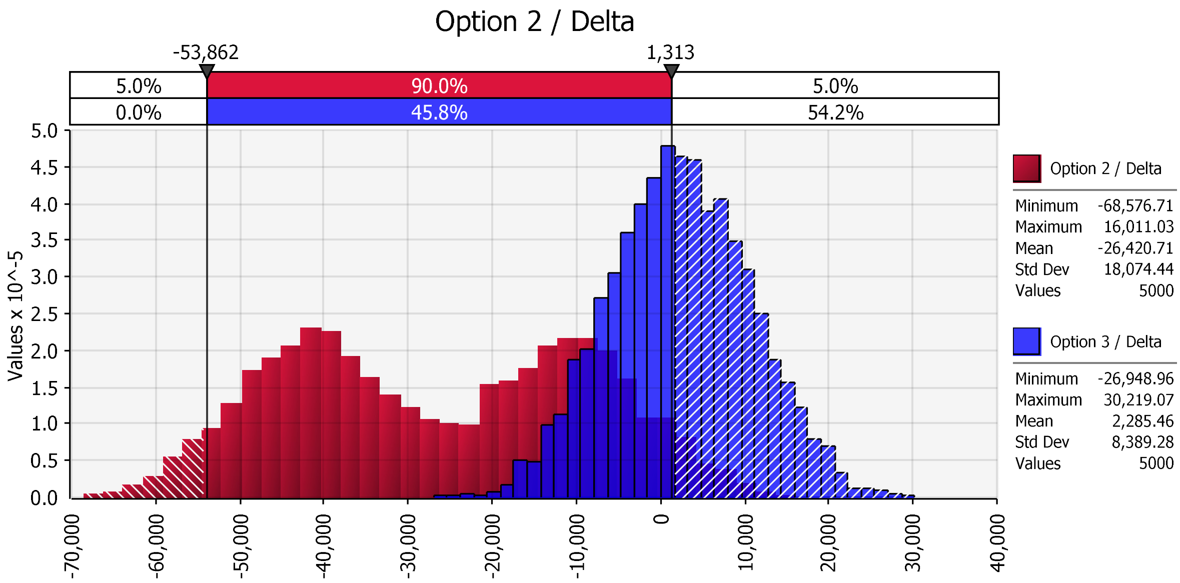


Figure 6: Volume Driver – Total Project Cost Analysis

175 Cable costs have been excluded from this analysis; see discussion on cable costs later in this section.
176 Baseline data provided in the Business Plan Data Tables provided in December. Additional data on uncertain schemes were provided via response t0 SPT Cost Assessment SQ47 in April.

5.27 On this evidence, more granular rates that reflect known cost drivers (such as a separate OHL reconductoring rate and OHL new build, and a separate rate for new build substations as well as one for modifying existing substations) would represent less risk to consumers and SPT and provide more efficient cost reflective allowances.

5.28 If Ofgem do not deem this acceptable then any Ofgem proposed rates need to be informed through more in-depth analysis of the specific areas. Ofgem have derived their volume driver rates using substation, overhead line and cable variables as a function of the Total Project cost. As we have shown above, the rates Ofgem have proposed with this approach would mean that we would not be able to recover anywhere near the efficient costs incurred by SPT. Therefore, any substation rate needs to be informed and analysed in isolation rather than as part of a wider regression analysis with the same process being applied to linear elements. This can be achieved through modifying the Ofgem model to have a total substation cost, total overhead line cost and total cable cost for each project (along with the associated civils and other (direct) costs for each element) and then a regression analysis can be applied to these individual cost areas rather than Total Project cost.

5.29 This is illustrated further when analysing the individual components.

Substations

5.30 Ofgem's proposed single rate for shared-use schemes leads to more risk since scopes of works can vary from one new 132kV line entry circuit breaker which would over fund such a project by £3.4m, compared to a brand-new substation with a new transformer, with one example being underfunded by £5.13m. Shared Use infrastructure schemes tend to be more expensive and therefore have a greater impact on any analysis showing funding performance.

5.31 This generic approach leads to higher risk for TOs and consumers than is necessary with results purely dependent on which combination of projects materialise during the period. As we have shown in our analysis here and in Annex 20 to our December Business Plan, having different volume drivers for different types of projects will ultimately lead to greater cost accuracy. It is understood there needs to be a trade-off between complexity and accuracy in order to ensure as little regulatory burden as possible. However, if volume drivers can be tied to project outputs such as a transformers or new substation land purchase, then it can be clearly reported.

Overhead Lines

5.32 SPT proposed several overhead line rates as costs can vary between reconductoring projects, new wood pole construction and new steel tower builds. Ofgem has proposed a single rate of £53k per circuit kilometre for all overhead line works.

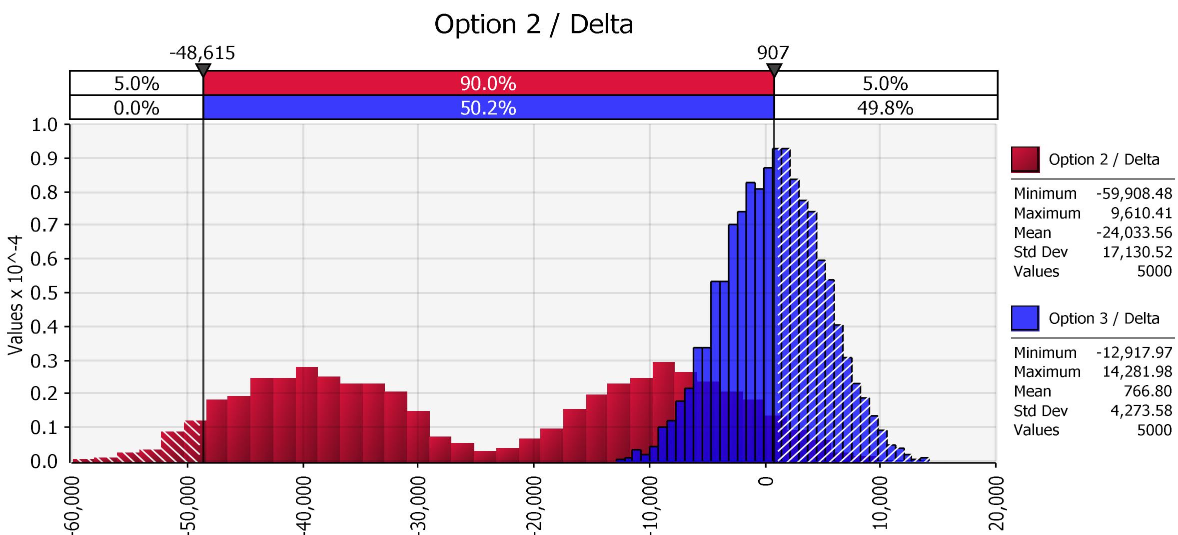


Figure 7: Volume Driver – Overhead Line Analysis

5.33 Figure 7 shows the results of a further Monte Carlo analysis to compare the performance of the SPT proposal for overhead lines (in blue) to the Ofgem proposal (shown in red). Ofgem's proposal would result in SPT being under-funded severely in almost every scheme. Further, the mean funding error for Ofgem's proposed rate is -£24m, compared to a mean in SPT's proposed approach of £0.77m. Note that the Ofgem cost difference is widely spread, with combinations of projects that require new overhead line build particularly disadvantaged. This analysis examined only the overhead line component of projects. This is where using a regression analysis does not translate into actual project costs. Most of our new connection schemes are in areas with little infrastructure and therefore new overhead lines will be required and cannot be delivered for £53k per circuit kilometre. The Ofgem regression model has not split out overhead lines into reconductoring and new build schemes. Also, volumes for different voltages of conductor have been grouped together, which will lead to distortion in the results. For a more accurate analysis of overhead line costs, this split is essential. This is also true for cable circuits. As discussed previously, this can be achieved through modifying the Ofgem model to allow for this type of analysis and using this method rates of £613k per cct km (new build wood pole overhead line) and £210k per cct km (reconductoring) would be derived.

5.34 A single overhead line rate is not in the best interest of consumers as it leads to a poorly performing cost driver. SPT had proposed separate rates for reconductoring, new build wood pole and new build tower to ensure, where appropriate, the lowest cost solution could always be utilised. It is important to have this level of flexibility in what solutions can be offered to customers and also to ensure that the most technically effective as well as efficient solution is implemented.

Cable

5.35 Similar to overhead lines, Ofgem's proposed cable rate is extremely low for the types of work forecast for RIIO-T2. The rate does not take into account size, material or number of cables per phase. As discussed in our analysis of Ofgem's cost assessment model in Chapter 2, Expenditure and Outputs, Ofgem have not taken these considerations into account as part of their asset unit cost assessment for cables. Further, the data set that has been used is very small and is not statistically relevant for this purpose.

5.36 These variables change from project to project to ensure that the most economic and efficient design is proposed and there is rarely a standard cable solution. This is why we believe that a schedule of cable rates is more appropriate. A schedule of rates would allow efficient funding for individual cable sizes, ensuring the most appropriate cable size can be utilised for each project and preventing any long-term inefficient cost if the wrong size is selected.

5.37 It is evident that each individual variable (substation, overhead line and cable) needs to be subject to its own analysis to ensure any proposed volume driver rates is efficient for that specific project component. This will also allow analysis to be cognisant of the different project scopes within each component such as new build vs reconductoring.

5.38 For the various reasons outlined above the SPT approach, utilising a disaggregated volume driver (£/MW and £/MVA for substation works with shared use split up into three separate areas and £/cct km for linear assets split by voltage and work type), represents a more cost reflective proposal with rates derived with deeper insight into actual project cost drivers.

5.39 Finally, we see no proposal from Ofgem on how cross-price control outputs will be funded regarding this mechanism and others. This was an issue raised as part of our December Business Plan Submission in our uncertainty mechanism Annex and we seek further discussion with Ofgem on this.

Shunt Reactor

5.40 In our Business Plan - Annex 20: Managing Uncertainty, SPT had proposed a unit cost allowance as part of our "Net Zero - Operability" Mechanism to fund additional reactors and therefore we welcome this new proposal included in Ofgem's Draft Determination.

5.41 SPT's approach involved a unit cost allowance of £2.395m for additional 60 MVA shunt reactors which would be triggered by the ESO submitting an STC planning request or non-compliance with the relevant engineering standards. This is not too dissimilar from Ofgem's proposal and we would suggest a unit cost allowance for different sizes of reactors as the basis of the mechanism.

5.42 We look forward to engaging with Ofgem to further define this area.

Opex Escalator

5.43 An Operational expenditure (Opex) adjustment mechanism has been proposed by Ofgem to increase operating and indirect costs relative to an increase in Capital expenditure (Capex) above the annual baseline expenditure. The Opex Escalator is proposed to operate on both Closely Adjusted Indirects (CAIs) and Network Operating Costs (NOCs) on a similar basis with different rates applied – 0.5% and 0.754% per annum, respectively. Whilst we welcome Ofgem's agreement, in ET Annex 4.64, to *"…the principle of costs arising from new assets being installed onto the network is sound…"* we do not agree to the approach and proposed rates stated in the Draft Determination.

5.44 As discussed in Chapter 2, Expenditure and Outputs and SPTQ14 we disagree with Ofgem's approach to assessing networks' Opex requirements and therefore also disagree with how % uplifts have been derived for this mechanism. See the relevant Opex section within Totex Chapter for our additional arguments on this subject.

5.45 As part of our Business Plan submission SPT proposed a 1% (of total capex cost) Opex adjustment which was in line with the RIIO-T1 approach to increasing operating costs associated with any increased in capital expenditure. This worked well in RIIO-T1 and it is our opinion that this should be maintained for the RIIO-T2 period. Ofgem's proposed rates would not cover our increased operational requirements as our asset base continues to grow.

5.46 We have highlighted our concerns with the indirect costs modelling approach in the Totex Chapter. Further details on this are provided in our response to SPTQ15 (included within Chapter 2), NERA's report concludes that Ofgem's statistical models are not sufficiently reliable to support its conclusions on the efficient levels of Indirect costs that SPT requires over the RIIO-T2 control period. A consequence of this is that it would be premature to agree to a CAI uplift rate until the baseline allowances are better understood. We look forward to continued negotiation with Ofgem to determine a mutually agreeable position.

Responses to Consultation Questions – Uncertainty Mechanisms

Core Document

Q12. Do you agree with our proposed common approach for re-openers?

5.47 For all re-opener categories, we feel there needs to be a more nuanced approach with more frequent application windows. With Ofgem indicating a greater use of uncertainty mechanisms in T2, it is expected, as more of the current unknowns become known that TOs will be using these mechanisms extensively. One of the main benefits of different reopener windows would be a reduction in the regulatory burden on TOs and Ofgem as work is spread across different years rather than one single large submission. SPT, therefore, propose an annual reopener window across all areas reducing overall risk and preventing any unnecessary delays.

5.48 From our experience of previous re-openers in RIIO-T1 and RIIO-ED1, such as the 'Accelerated Electric Vehicle Investment' project, Ofgem must clearly set out the expectations of the justification that companies need to provide to Ofgem. It would be beneficial for all parties to have a defined minimum information requirement or a proposal template provided by Ofgem, forming part of the licence conditions, to ensure that Ofgem has access to the key information they need and that TOs can focus their efforts on gathering this information. We expect the requirements to be comparable to the Engineering Justification, CBA and stakeholder support that is provided with individual projects submitted as part of the RIIO-T2 Business Plan as the likely value is comparable.

5.49 As part of this definition a clear timetable for an Ofgem determination outcome needs to be specified, particularly where customer projects could potentially be impacted. Many of these will relate to Net Zero and customers may be dependent on them for future connections for generation or demand, therefore any delays in the process will come at a cost to customers. SPT has concerns over the timing of some of the proposed re-opener windows. For example: the MSIP re-opener is proposed for January 2024 alongside an end of period true up. We feel this is too late and increases the risk that projects do not achieve the required criteria and therefore experience delays in commencing. Business plans will have been submitted 15 months before RIIO-T2 starts - a more effective approach would be to have an annual reopener linked to the outcome of the NOA process would be a more efficient approach and would also cater for eligible connection projects that may arise at any point in time. This approach is also supported by stakeholders who recognise that without such an approach, connection projects may be jeopardized.

5.50 We see little advantage in placing the reopener window in January. If efficient expenditure has already been incurred (or is still being incurred) the regulatory year will not have ended. If the spend is in respect of the previous regulatory year, the window will be 10 months after the end of that year and the earliest expenditure could be recovered would be a further 15 months down the line i.e. 12 months to include it in published tariffs and a further three months to the beginning of the next regulatory year to actually start expenditure recovery. A May window, for example, would allow already incurred expenditure in the most recent regulatory year to be included in the tariffs come January.

5.51 Ofgem cannot have the discretion to apply re-openers to adjust outputs or allowances at any point (paragraph 7.16 of the Core Document) or against any category whilst TOs are required to provide a clear definition of re-openers that they may need to trigger. We consider this to be double standards. An Ofgem reopener would undermine the whole principle regulatory certainty of the price review process and represents a material departure from the objectives of the RIIO model.[177] Furthermore, such an approach would be likely to damage investor trust and confidence. Mechanisms are in place such as PCDs to hold a company to account and if outputs are not delivered then there are in-built true up mechanisms reducing any risk to consumers.

[177] See, for example *"Handbook for implementing the RIIO model"* Ofgem, 4 October 2010: "*5.6. Network company decisions will be influenced by their perceptions of the credibility of the regulatory framework. The RIIO model is designed to provide certainty and transparency about how the framework will work in the future. As part of this, we will seek to avoid any retrospective/ex post adjustments to the package agreed in final proposals and licence modifications as this could undermine regulatory commitment."*

5.52 We support the aggregation of some re-openers in the context of materiality threshold, but it needs to be clear which mechanisms are subject to this aggregation. An example of this is Ofgem's proposal that schemes associated with network operability issues such as intertrips and harmonic filters fall under an element of the reopener that needs to be "aggregated" to trigger the process. Whilst we agree that such items should be subject to a reopener, it is our opinion that these should not form part of the "aggregated" reopeners and should be treated separately. Operability schemes are triggered by the ESO, outside the control of SPT. These are generally relatively low value and provide a very cost-effective solution to managing network constraints and providing access to the network. Due to this low value and the relative benefits we feel this area should not be subject to aggregation or a materiality threshold.

5.53 As outlined below in our MSIP section and illustrated in the example below, we don't propose that a 1% materiality threshold should be standard for reopeners. This does not reflect the costs relative to each area and each case needs to be reviewed to understand cost requirements, we have illustrated this further in our response to ETQ13. We will seek further discussions with Ofgem on this point. We also do not agree that any re-opener materiality threshold should be based on costs that have been subjected to the TIM incentive rate. The need for a re-opener should not be based on Ofgem's confidence of baseline costs and we wish to see the removal of this.

Q13. Do you agree with our proposals on a materiality threshold, a financial incentive, a 'foreseeable' criterion, and who should trigger and make the application?

5.54 SPT has been involved in several Co-ordinated Adjustment Mechanism (CAM) workshops alongside TOs, DNOs and the gas companies in early 2020 and have seen our feedback incorporated into the design of this mechanism. We agree with the proposals put forward by Ofgem on the co-ordinated adjustment mechanism.

Q14. Do you consider that two application windows, or annual application windows, are more appropriate, and should these be in January or May?

5.55 For the Co-ordinated Adjustment Mechanism, SPT would favour an annual application window to prevent any project delays as they may be associated with a customer connection. As stated in the Draft Determination[178] any delays could be detrimental to the overall benefits that collaboration between parties could bring. Again, annual / other windows for specific elements on uncertainty mechanisms would assist Ofgem with resourcing and regulatory burden.

5.56 A May window would be preferable to align with the RIIO-ED2 planning process. Again, a clear and concise framework for proposals needs to be identified by Ofgem to ensure the quality of information provided is at the desired level and decision timescales by Ofgem also need to be specified.

Q15. Do you consider that the RIIO-1 electricity distribution licences should be amended to include the CAM, or wait until in 2023 at the start of their next price control?

5.57 With the RIIO-ED1 price control period entering its final years and the CAM not being incorporated into the Transmission Licences until April 2021 there is reduced scope for distribution companies to use this mechanism between themselves.

5.58 Option a) in Section 7.57 in the Draft Determination Core Document ensures that as long as one party has the licence condition an application can be made. Since this mechanism is for transferring baseline funding and RIIO-T2 plans have been created with engagement from distribution companies then we feel an immediate amendment to the RIIO-1 electricity distribution licenses is not required. We therefore submit option a) is the most appropriate.

[178] Draft Determination – Core Document: Paragraph 7.52

Q16. Do you agree with our proposed re-opener windows for cyber resilience OT and IT, and our proposal to require all licensees to provide an updated Cyber Resilience OT and IT Plan at the beginning of RIIO-2?

5.59 We broadly welcome the re-opener windows, however the baseline Totex value is insufficient to enable efficient progress towards the objectives set out in the RIIO-T2 Cyber Resilience plan. The required certainty to make the necessary progress necessitates a very short turnaround by Ofgem between the first re-opener submission and decision if the proposed baseline funding is not increased.

5.60 We also note that there is a measure in the "Use or Lose it" allowance aspect that considers milestones achieved. As Ofgem acknowledge in paragraph 7.67 of the Draft Determination Core Document, this is a new area and the experience we have to date in this area shows considerable uncertainty in the full delivery timelines. The solutions employed in this area need extensive adaption which causes a degree of uncertainty that can be incompatible with the concept of delivery milestones. This gives rise to some concern and we hope that this is recognised by the pragmatic definition of these milestones.

Q17. What are your views on including the delivery of outputs such as: CAF outcome improvement; risk reduction; and cyber maturity improvement, along with projects-specific outputs??

5.61 We agree in principle for these types of outputs to be included. SPT are measuring the cyber maturity at present and are looking for improvements over the course of the different plans. However, the specific measures would need to be agreed so that they are quantifiable. In addition, there may be factors outside of the control of SPT that would influence this. For example, if the wider threats increase, then this would need to be considered in the assessment of risk reduction.

5.62 As Ofgem have only provided seed funding to SPT as part of the Draft Determination and have not quantified the time between submission of the revised plan in March to the outcome of this assessment, this would also need to be considered in the assessment. This decision has consequentially increased the risk being faced by SPT as the projects cannot progress as there is a risk that they will not be funded. The impact of this delay will need to be included in the assessment of the outputs that can be measured.

Q18. Do you agree with our proposal for the Non-operational IT and Telecoms capex re-opener?

5.63 We broadly welcome a re-opener mechanism to deal with uncertainty in this area. We agree the provision of an application window very early in RIIO-T2 (April 2021), as suggested by Ofgem on page 74 of the Draft Determination Core Document, is necessary to ensure that we can deliver on commitments set out in our Business Plan.

5.64 This does, however, require clear and unambiguous guidance from Ofgem on both the information to be submitted by TOs and the approach to be taken by Ofgem to assess each submission. The provision of multiple re-opener submissions in the same time period is a concern and further clarity is required on the allocation of resources by Ofgem to undertake such assessments on bespoke, complex and specialist projects. It requires a very short turnaround by Ofgem between the first re-opener submission and regulatory decision for such schemes.

5.65 Ofgem's rationale for the timing of the second re-opener window (January 2023) compared to alternative dates is less clear. On the assumption that the second date is driven more by statutory/ regulatory requirements, as stated in the Draft Determination, which are beyond the reasonable control of TOs, we consider that greater flexibility may be necessary on the timing of this window.

Q19. Do you agree with our approach to using a re-opener mechanism for changes to government physical security policy?

5.66 We agree that changes to the necessary expenditure associated with government physical security policy are outside SPT's control so welcome the provision of a re-opener mechanism. However, the materiality threshold is set so high that the costs of the entire RIIO-T1 programme for this activity would not have triggered the mechanism. As stated in the section relating to MSIP below, further consideration on the threshold and timing of re-opener windows is necessary.

Q20. Do you agree with our approach regarding legislation, policy and standards?

5.67 SPT had proposed several re-opener areas under a "Legislative, policy and standards Re-opener" in Annex 20: Managing Uncertainty in our Business Plan. Several of these are now covered under Ofgem's proposed MSIP Re-opener. However as outlined in the Core Document there are several areas where Ofgem state that further justification is required. These include:

- Brexit
- Environmental Enhancements
- Non-Rechargeable Diversions
- Wayleave Review Adjustment
- Environment and Climate Change uncertainty

5.68 We feel there is suitable justification for the reinstatement of these re-opener areas. For example, SPT will not be able to achieve all the objectives of our Environmental Action Plan that Ofgem has **approved** without an environmental reopener. No allowance forecast can be made for these areas or else they would be included as part of baseline allowances. As such it is difficult to set out in our justification the overall financial impact of why these reopeners will be required. However, we know these areas will directly have an impact on SPT in the RIIO-T2 period and a re-opener is required to ensure sufficient funding is available particularly for activities relating to the environment which will take on a greater importance as we push to achieve Net Zero. We have designed each reopener to be as concise as possible, yet it must be noted that as these are unknown areas and some degree of flexibility is required to ensure SPT can adapt to future challenges.

5.69 We set out below our views on the justification for each re-opener area:

<u>Brexit</u>

5.70 The timing and impact of the UK leaving the European Union continues to be unknown, (although the timing is now more certain). As a result of the process of leaving the European Union, additional costs may be incurred due to changes in import tariffs affecting the costs we incur. In general, the vast majority of SPT's assets will be procured from international markets. With the size of the expected increase in our asset base over the RIIO-T2 period we will be sensitive to any increase in import tariffs. Given the lack of clarity relating to when the UK's Brexit negotiations will conclude, this may lead to additional costs. We propose to use this mechanism only in the event that a material change to efficient costs is experienced resulting from increased import tariffs.

5.71 Furthermore, as we have seen a dramatic reduction in allowances associated with "Risk and Contingency" for every project, there is no provision to cover any additional charges within the total project costs. This places even greater importance on the need for this re-opener.

5.72 Whilst Ofgem has proposed an adjustment to reflect RPEs, the associated indices will not have a direct correlation to Brexit impact on these such as new/increased trade tariffs.

Environmental enhancements

5.73 We have included a number of commitments as part of our Business Plan (in the chapter 'An Environmentally Sustainable Network' on pages 35-47) in relation to the steps we will take to reduce the environmental impact of the network. These were accepted by Ofgem in the Draft Determination and this reopener is vital to ensuring funding for any activity. The commitments we made include:

- We will target zero environmental regulatory interventions and notifiable breaches of legislation.
- We will implement a programme to identify, risk assess and address high risk legacy land contamination.
- We will work collaboratively with our stakeholders, including the other TOs, throughout RIIO-T2 to develop and pilot a common approach and robust methodologies for delivering Biodiversity Net Gain alongside Natural Capital assessment and enhancement.
- We will pilot these biodiversity and natural capital assessment methodologies and associated tools on selected RIIO-T2 projects.
- We will embed these biodiversity and natural capital assessment methodologies and associated tools in our business decision making processes for projects and the management of existing sites.
- We will identify, and subsequently monitor and annually report, metrics to baseline and track the levels of biodiversity and value of natural capital on our sites and the achievement of our targets.
- We will work with our local communities, landowners and other stakeholders to deliver 'no net loss' in biodiversity and identify options for delivering 'net gain'. (We have proposed a bespoke discretionary financial Operator Defined Incentive that includes a reward for delivery of biodiversity net gain as one of three components. Cost recovery is not part of this ODI.)

5.74 We will work with our local communities, landowners and other stakeholders to deliver a net positive impact in natural capital across our existing sites.

5.75 In respect of biodiversity, a means of measuring levels of biodiversity and any improvements is still being developed by the Scottish Government and Scottish Natural Heritage and will not be completed prior to the start of RIIO-T2. We expect this will require all construction projects to have no net adverse biodiversity impact as a minimum, moving to a net gain target, potentially during the RIIO-T2 price control period (as is happening in England). Even once a metric and target are identified, the associated costs of the work required to deliver the targeted improvement will be very site specific. Various environmental upgrades will be required to our network on a site by site basis, relating to ecological impacts, legacy land contamination or other environmental impacts that require resolution or improvement.

5.76 The full range of activities, and any associated expenditure, required to deliver these commitments and reduce our impacts cannot be identified at this time. Therefore, the costs associated with the necessary biodiversity and land improvement works are not included in our baseline costs. This is due to:

- Lack of maturity of consideration and management of the issue (e.g. lack of data, metrics, management processes and/or Government policy)
- Site or project specific nature of the required activities; and
- Potential legacy issues at some sites that are not recorded in current systems.

5.77 We do not believe it is in the best interests of the consumer to forecast such costs on an ex-ante basis as the associated targets and means of achieving the targets are not yet defined. Therefore, a mechanism is required to fund these steps efficiently.

5.78 We will be establishing a baseline for our existing sites before and into the first year of RIIO-T2, and thereby identifying a metric against which to measure improvements and target delivery. Each RIIO-T2 project will also have such a baseline established as part of site survey works. Along with further guidance for Scotland, this will enable us to provide a more accurate and comprehensive cost forecast as part of the reopener.

5.79 We estimate the total expenditure on this to be between £13-15m. These solutions are in the interests of wider society as opposed to being related to the operation of the network itself or of benefit to SPT, therefore we consider these to be relevant for funding.

Non-rechargeable diversions

5.80 Non-rechargeable diversions or compensation payments are triggered by landowners or developers as a result of the ownership of land being transferred or where no current valid land rights exist due to historical land-rights no longer being valid. Whilst in some cases this can be resolved by securing new land rights, the valuation principle for securing those rights is based on the associated loss. This must be balanced against the economic value in retaining the asset and in some cases, the associated loss results in a requirement to re-site the infrastructure. We have experienced an increase in the number of these claims as a result of land ownership being transferred, particularly for new housing developments. The associated loss that can arise can be substantial which may lead to the assets requiring diversion.

5.81 The loss of land rights is out of our control as we cannot influence the transactions that landowners make nor the future plans for the use of such land. We proactively pursue the management of our land rights in such situations but not every transaction is visible to us.

5.82 An example of this in RIIO-T1 was on an overhead line over land in Glasgow. This span formed a critical route of the transmission network which was previously held by wayleave from the previous landowner before the land was sold to another party. The land on which the overhead line is located was identified for future development. SPT was served a removal notice in 2014 to remove its line and towers.

5.83 In parallel to the ongoing Necessary Wayleave process, SPT engaged in a voluntary negotiation to agree a compensation figure based on the perceived loss of developable land and the impact on house value sales due to the existence of the SPT's OHL. The negotiated compensation figure was analysed by SPT to consider the potential diversion costs of the overhead line and in both cases, diversion was deemed to be significantly higher than the compensation agreed to retain the line and obtain permanent servitude rights. Examples such as this are becoming more prevalent. The trigger for a reopener would be the third-party serving notice for such a diversion.

Wayleave review adjustment

5.84 [redacted].

5.85 [redacted].

5.86 [redacted]

[redacted].

5.87 [redacted].

Environment and Climate Change uncertainty

5.88 It is currently unknown what Government Policy will be implemented over the RIIO-T2 period to accommodate legislative amendments as a result of the Committee on Climate Change's (CCC) recent recommendations and other policy developments in respect of Net Zero. The Scottish Government have passed legislation relating to Scotland achieving net zero GHG emissions by 2045 as well as an interim objective of 75% reduction by 2030.

5.89 These could affect any part of our business operations with various levels of impact. An example of this is the recent experience with the introduction of Regulation 2019/1021 (which repealed and recast Regulation (EC) No 850/2004) on persistent organic pollutants which reinforces the urgency of SPT having access to funding to ensure we remain compliant to any upcoming legislative amendments. This change relates to the use of polychlorinated biphenyls (PCBs), which have been linked to reproductive and immunotoxic effects in wildlife and their use has been effectively banned in the recent legislative revision. Due to this change to legislation, our draft business plan from October was revised to include this new legislative requirement in our December Business Plan. This is an example of legislative change which can emerge in a short timescale and result in additional, material costs.

5.90 Another example of legislation that will potentially impact SPT in this area is The Clean Energy Package. The Clean Energy Package is due to be transposed into UK law on the 31st December 2020. BEIS are currently consulting on the drafting of the relevant Statutory Instruments, with Ministerial sign off expected to take place on the 12th October 2020. Whilst we are not currently aware of any direct impacts the CEP may have on our RIIO-T2 business plan, the consequences of the required activities on our Transmission Network such as the new requirement for network companies to develop Network Development Plans are unknown.

5.91 Furthermore, SPT use a range of technical solutions and materials across our networks which may be subject to future legislative restrictions. One example of this is Sulphur Hexafluoride (SF_6) which is a gas used extensively in electricity transmission and distribution as an insulator and arc-quenching medium in high voltage equipment such as circuit breakers, gas insulated switchgear (GIS) and gas insulated busbars (GIB). SF_6 is, however, a fluorinated gas (F-gas) and a potent greenhouse gas with a Global Warming Potential (GWP) 23,900 times that of CO_2. Given the newly established Net Zero target, which also relates to the use of SF_6, the likelihood of further legislative amendments aimed at reducing the use of this gas is perceived to be relatively high.

Q21. Do you agree with our overall approach to meeting Net Zero at lowest cost to consumers? Specifically, do you agree with our approach to fund known and justified Net Zero investment needs in the baseline, and to use uncertainty mechanisms to provide funding in-period for Net Zero investment when the need becomes clearer?

5.92 We agree that there must be a focus on meeting Net Zero efficiently and at the lowest overall cost to consumers, but this must be assessed over an appropriate time period. This was a material factor in the preparation of our Business Plan. We also agree that the regulatory framework requires flexibility to cater for the inherent uncertainty in the delivery of projects for Net Zero. However, we do not believe Ofgem has struck the right balance. The RIIO-2 Draft Determination seeks to reduce costs to consumers in the short term, but this is to the detriment of future consumers and will increase overall costs in the longer term. Projects already identified by SPT, which have been transferred into uncertainty mechanisms or are subject to unjustified efficiency challenges, will result in delays for customers' connections due to companies being unable to commit to investment without greater certainty. These delays in connections will increase costs in the long-term. Additionally, the efficiency adjustments that are being made will require non-core elements of the work to be re-scoped to ensure that sufficient allowance is available.

5.93 Ofgem have previously set out their expectation for networks in the letter from Akshay Kaul on the 8th August 2019 ('RIIO-2 response to Committee on Climate Change's Net Zero Report'[179]). In this letter, reference is made to the Committee on Climate Change expectation that:

> "*the approach to grid capacity augmentation should be somewhat 'future proof', meaning that where upgrades occur, they should be to a size sufficient to ensure no future augmentation at the relevant site would be required prior to 2050*."

5.94 Ofgem are encouraging companies to future proof their networks and invest in the future but this requirement has not been reflected in Ofgem's Draft Determination. The cuts that have been made, in particular to benchmarking and ongoing efficiency, will require a significant revision on the scope and ambition of our activities. Ofgem's inconsistent messages make it very difficult to plan how we are to approach the energy transition.

5.95 For example, the cost adjustments that have been made to aspects of the SPT plan will limit our ability to invest in creating long term benefit, such as the incremental cost for alternatives to SF6. These alternatives come at a higher cost, but the approach taken to the cost assessment of such initiatives does not provide us with sufficient allowance for these environmentally beneficial alternatives, as detailed in our Totex and Environment chapters of our response. This is counterproductive; we expect that these assets will operate on the network until at least 2065 and in that period, it is reasonably expected that legislation may require the removal of SF6 due to its known impact on the environment. Ofgem's Draft Determination does not account for the fact that these alternative approaches have a higher capital cost. This is not compatible with Net Zero ambitions, nor in the interests of consumers.

5.96 There are further risks stifling the investment required for Net Zero. The current portfolio of uncertainty mechanisms pass an unacceptable level of risk on to companies with the proposed rates of return. For example, the MSIP proposes to only provide companies the opportunity for a re-opener application in 2024. We expect a Contracts for Difference (CfD) auction will take place in the next 12-18 months which will attract bids from generation connections in the period 2023-25. If this does take place, the current MSIP proposals will not provide Transmission Owners with any allowance certainty until the project is well progressed, or even completed. Network operators cannot be expected to commit to projects with no certainty of the costs being covered.

[179] https://www.ofgem.gov.uk/system/files/docs/2019/08/letter_to_networks_on_achieving_net_zero.pdf

Q22. Do you think the package of cross sector and sector-specific UMs provides the appropriate balance to ensure there is sufficient flexibility and coverage to facilitate the potential need for additional Net Zero funding during RIIO-2?

5.97 No, we explain this in more detail in our response to specific uncertainty mechanisms in the rest of this Chapter. A broad package of uncertainty mechanisms is critical to the operation of RIIO-T2 in light of the approach that has been taken of a low cost, high confidence baseline plan. The range of uncertainties that may emerge over the RIIO-T2 period also make this critical. This includes uncertain volumes of new generation connecting, changes to electricity consumptions from the electrification of transport and heat, and other policy developments that may be made by government that could directly or indirectly change the requirements of the electricity network.

5.98 There are a number of significant concerns about the proposed uncertainty mechanisms, as described in the rest of this Chapter, in particular the response to questions: Core Document Q12-20, ET Q10-13, Most notably, there are a concerning level of errors and inconsistencies in the calculation of the volume driver for new connections. Additionally, we do not consider that the approach that has been taken is fair nor cost reflective. A full analysis of this is provided above.

Q23. Do you have any views on our proposed approach to a Net Zero re-opener?

5.99 We are concerned that the proposed Net Zero re-opener is triggered at Ofgem's discretion. This point is one of many that we flagged in our response, dated 22 May 2020, to Ofgem's open letter on the Net Zero Re-opener. It is the TOs, not Ofgem, that closely manage and have visibility of developments on their networks. For example, TOs gain early insights from regular discussions with stakeholders. Ongoing engagement by Ofgem (such as through calls for evidence) is necessary to ensure that the views of network operators are reflected through this process to inform the need for any further re-opener. Required projects need to be progressed quickly, with appropriate Ofgem oversight. Naturally, it is important to ensure that Ofgem will have necessary resources to facilitate this. Given the approach Ofgem have taken in creating a very high threshold for "certainty", and the creation of PCDs which should allow for a natural adjustment of any spend that is not required, the likelihood of a re-opener being required to reduce a company's allowance seems highly unlikely.

<u>Electricity Transmission Annex</u>

ETQ10. Do you agree with our proposed eligibility criteria for the LOTI re-opener and do you agree with the assessment stages, and their associated timings?

5.100 Since last year, SPT has been heavily involved in the Large Onshore Transmission Investment (LOTI) working group with Ofgem and the other Transmission Operators. This will be an important mechanism to fund large boundary investment, increasing capacity across the GB network in the RIIO-T2 price control period. We have been encouraged by the positive discussions at this working group, in particular the clear timelines proposed for the LOTI process that still allows for flexibility, being cognisant of the complex nature of these schemes.

5.101 The LOTI mechanism is an evolution of the current Strategic Wider Works process and we welcome the further work to refine the mechanism with Ofgem and the remaining TOs. We agree with the first two bullet points in Paragraph 4.25 of the ET Annex. We do not agree with the third bullet point that will bring non-load projects into the LOTI mechanism. This had previously been discussed at an early working group meeting[180] and it was decided that LOTI would not be used for any non-load related projects. The new decision was not discussed at the working groups or licence drafting working groups since then. It follows that this new category of LOTI projects has not been the subject of consultation to date, and the practical implications of this have not been considered. This criterion should therefore be removed.

[180] Large Onshore Transmission Investment Workshop held on October 1st 2019

5.102 LOTI projects may be subject to competition (and our comments on competition are set out in the Competition Chapter). Non-load projects will not fulfil the criteria as “separable” and so we do not see how they could be subject to competition, and therefore fit within LOTI schemes. It is also noted that the NARM mechanism is intended to be used for this type of investment. Ofgem has not demonstrated how the linkages between these mechanisms will operate and the proposals for NARM are silent on LOTI.

5.103 Overall, we are reasonably comfortable with the assessment stages and associated timings proposed by Ofgem and we note that TOs will be able to outline alternative timings for the process in exceptional circumstances. We would however raise the following issues.

- For the Initial Needs Case and Project Assessment a range of 6-12 months for assessment feels too wide in our opinion and this should be narrowed down to 6-9 months to give greater confidence over the decision timescales and allow for further development of schemes. These are important projects with huge impacts on the UK Network with substantial costs so there needs to be confidence in these schemes in order for them to be progressed. Any delay to decisions can have major implications on project timescales, which necessitates a smaller more defined decision window.

- Ofgem propose the “Project assessment” stage occurs when the majority of procurement is finalised. This could imply that the TO is required to have in place its contracts for the project. The description should make it clear than in respect of contracts, this should be when contract negotiations are in their final stage.

5.104 Lastly, paragraph 4.31 of the ET Annex refers to Ofgem setting out additional detail on LOTI in a separate Guidance document. TOs have still not been issued with the associated LOTI guidance documentation. This guidance is of key importance to understand how (and if) the LOTI mechanism will operate in practice and we need to receive this guidance as soon as possible. In particular, we need to see any guidance documents before the licence drafting consultation expected in September. We need complete clarity on which aspects of the process will be set out in the licence and which in the guidance. For example, it would not be appropriate for the LOTI criteria to be included in the Guidance only, given the ability of Ofgem to modify guidance without the same protections we have for licence modifications.

ETQ11. Do you agree with our proposed definition of PCF for RIIO-2, and the areas of work that we intend that definition to cover?

5.105 We do not agree with Ofgem’s definition of PCF for RIIO-T2. The definition of pre-construction works was an area that we (TOs) clearly defined to Ofgem during development workshops held during 2018 and 2019. Firstly, the definition should not be linked to the LOTI mechanism. Secondly, the purpose of ‘pre-construction’ works is not simply there to meet basic ‘permission’ type obligations (e.g. consents as proposed in this mechanism); rather it is a necessary part of best practice project management and must be available until the ‘construction’ stage to support effective risk management and cost control. Whilst this does make it more suited to large/ complex and uncertain schemes (e.g. SWW/LOTI) it is not an exclusive relationship, hence, Ofgem’s arguments (ET Annex paragraphs 4.34 -4.36) are not tenable, e.g. ‘consents’ are not obtained for a project; rather they are obtained for the physical solutions (assets) that constitute the project.

5.106 Due to this SPT submit that PCF should be defined as expenditure up to the point of construction. We propose a definition of pre-construction activities as the initial activities undertaken by the licensee to develop the technical design plans and obtain the necessary planning or development consents in preparation for constructing prospective projects on the National Electricity Transmission System. Such pre-construction activities would include:

- routing, siting and optioneering studies – detailed route assessment studies carried out to identify preferred routes and sites for transmission infrastructure.

- environmental assessments – including desktop studies to inform routing study process, initial environmental walkover surveys and detailed environmental studies and impact assessments.

- project design studies and selection – technical system studies/reports, CBA and cost assessment and review of high-level options taking account of environmental, technical and cost factors.

- technical specifications for cost tenders.
- planning and/or development consents.

5.107 This is not an exhaustive list and there may be other items required not outlined above but it provides a high-level summary of “typical” activities undertaken in the initial development of projects.

5.108 SPT propose that any PCF, in relation to LOTI schemes, should be linked to the Initial and Final Needs Case submissions. Due to the nature of the LOTI process any project development activities, outputs and appropriate allowances could be provided at these stages and then trued up upon final Ofgem assessment.

ETQ12. Do you agree with our proposal to assess PCF costs as part of RIIO-2 Closeout, following the principles set out in Chapter 4?

5.109 The SPT baseline pre-construction allowance, proposed as a use-it-or-lose-it fund with named schemes, have been greatly reduced by Ofgem as part of the Draft Determination with no real justification from Ofgem. It is unclear what further information is required by Ofgem for these schemes to be included by Ofgem in the Final Determination. We would welcome further engagement with Ofgem to understand both Ofgem’s justification for the reduction and what further information we can provide to facilitate an increase in the allowances.

5.110 We believe a use-it-or-lose-it allowance is a relatively low-risk approach to providing PCF in the RIIO-T2 period. If the named scheme is no longer required, then the allowance is simply recovered. Likewise, if the scheme changes in scope or is replaced, then an application can be made to Ofgem to transfer allowances to a new output as per the RIIO-T1 process. Furthermore, a baseline allowance prevents any delays in project development whilst allowing for timing flexibility within period.

5.111 There are several schemes as part of the RIIO-T2 baseline PCF funding that are not subject to the LOTI process (NOA, Generation closures, etc) that will have access to no funding now that the associated baseline allowance has been reduced. These schemes are likely to be required in the RIIO-T2 period and we have provided additional evidence outlining why these should be reinstated in our updated EJP_SPT_SPT200136 provided to Ofgem separate to this response.

5.112 If pre-construction funding is to be tied to LOTI projects, then it would be better placed to fit inside the LOTI process with pre-construction being reviewed at the Initial and Final Needs Case Stage and appropriate efficient allowances being provided subject to Ofgem assessment at these stages. This would avoid the need for an ex-post adjustment at the end of period.

5.113 SPT consider that 2.5% of total anticipated project cost cannot be considered as a standard for defining efficient pre-construction funding. The SPT delivery model, where we carry out in house design in advance of tendering, as opposed to design within contract EPC, would lead to higher pre-construction costs above this 2.5% value and we have outlined the overall benefits of this approach in our ‘Totex’ Chapter. PCF varies depending on the type of scheme (for example an offshore scheme will have different PCF requirements than an onshore scheme) and therefore having a standard % will not reflect the nature of different schemes. Furthermore, there will be differences in planning requirements between the Scottish TOs and NGET. Subsequently, for these reasons, a comparative PCF percentage cannot be applied. This would further back up the proposal that any PCF be linked to the Initial and Final Needs Case submissions for any LOTI scheme rather than at the end of period.

ETQ13. Do you agree with our proposed scope of, associated eligibility criteria for, and timing of the submission window under the MSIP re-opener?

5.114 With a push for a green post-COVID-19 recovery and increasing Net Zero targets we agree there is a clear need for this mechanism to cover important projects that would not be included under LOTI or funded via any volume driver. Similar mechanisms were proposed by all TOs in the December Business Plan submissions.

5.115 That being said, there is still a risk that any NOA project, identified and agreed through the annual NOA process, would not have any access to funding if the total project cost was below £25m. Additionally it is still unclear how funding for developing NOA projects will be granted if, for example, one year a “PROCEED” signal is given and then a “HOLD” the next. In our view a materiality threshold for NOA schemes should be removed considering these schemes are already reviewed via the NOA process. A minimum threshold consistent with other re-openers should be used for consistency. This approach would also support the use of this this mechanism for accommodating outlier generation connection projects.

5.116 Further to this, the “externally driven works” (as referred to in paragraphs 4.39 and 4.57 of the ET Annex) are all individually subject to a 1% (of annual average revenue) materiality threshold or a 3% aggregated threshold. Both of these are post-TIM. A blanket 1% is not appropriate for all reopener items. For example, an operational intertrip scheme will generally cost less than £1m and if a low number of intertrips are required then the materiality threshold will never be met. These schemes are directed by the ESO and required for network compliance yet will have no access to funding unless a sufficient volume is met. We propose that a set materiality threshold be derived for individual items and to discuss this further at a working group level. The materiality threshold should not be subject to the Totex Incentive Mechanism. With TOs being set different thresholds it would be unfair and discriminatory to apply the same threshold for the same reopener areas. As proposed in our Business Plan, the materiality threshold could be amended to 2% pre-Sharing Factor to ensure consistency.

5.117 A 2024 reopener window with an end of period ex-post adjustment places a high degree of risk on the TOs when developing projects until this point. TOs will have submitted business plans 15 months prior to the beginning of RIIO-T2 and as witnessed through the COVID-19 pandemic, a lot can change in that timeframe. We propose an annual reopener window to reduce overall risk to consumers and TOs and we believe this a more efficient alternative.

5.118 An example of this would be Branxton 400kV GIS which formed part of our December Business Plan Submission. Ofgem indicated in the Draft Determination that Branxton 400kV GIS could potentially be moved to this mechanism because, whilst there is sufficient justification, there are concerns over timing uncertainty. Branxton will be a 23-bay double busbar gas insulated substation with a project value of c£96m.This is a large high-value project that has a significant impact on the network. The substation will be required to provide six transmission interface points for the Firth of Forth offshore transmission system. Additionally, Branxton will provide two connection points for the proposed Eastern HVDC Link, between SPT and northern England in the NGET area. This link, proposed to be 2 GW in size, has been identified as a key enabler for the future connection of renewable generation in Scotland. The position of the substation as a strong node on the existing 400 kV system, whilst being in close proximity to the coast, minimises the level of additional onshore reinforcement required for the connection of an HVDC link.

5.119 At the time of submitting the Business Plan in December, the project was contracted to connect in June 2027. Due to recent developments, this has since been revised to September 2026. Due to this project having multiple drivers interacting and increasing the overall complexity of developing this project efficiently, we agree with Ofgem decision that Branxton would be better suited to the MSIP reopener rather than in the SPT baseline.

5.120 However, as described, this is a high-value and important project and waiting until 2024 to review this scheme is not in the best interest of consumers. It also places too much risk on SPT in developing this scheme and potentially impacts delivery timescales. This will be the case for any connection project that will be subject to this mechanism and Branxton provides a real-world illustration of this issue. A more efficient approach would be an annual reopener window, as outlined previously, to reduced overall risk and allow projects to move forward with no delay. If Ofgem do not permit an earlier reopener window for MSIP projects, then we will require a bespoke UM for this project.

5.121 Furthermore, for NOA projects an annual reopener window tied to the annual NOA process would allow projects to be developed in line with each individual year's outcomes and prevent any delays to these vital projects and would deal with any year-to-year NOA changes.

5.122 The announcement by EDF, on 27 August 2020, that Hunterston B Nuclear Power Station will be closing two years earlier than planned, further highlights the need for a flexible mechanism to deal with uncertainty in a rapidly evolving energy landscape. Our business plan, including our proposed Net Zero reopener to deal with network operability challenges, has been developed to deal with events like the early closure of large synchronous generation plant. It is vital that we have the ability to react and invest in response to such events or evolving network risks, in a timely and efficient manner. By ensuring that e.g. synchronous compensation equipment is installed at the right time and in an optimal location, we will limit the impact of various emerging operability challenges on consumers. While we note Ofgem's concerns regarding competition in the delivery of synchronous compensation in particular (table 39, SPT Annex), delivery delays or the installation of sub-optimal equipment will lead to much higher network management costs and risks than any savings that might be realised in a competitive process.

5.123 For these reasons described above, this mechanism requires a more nuanced approach rather than a single window for all. We expect this mechanism to be used extensively by all TOs and have concerns over the level of resources required from Ofgem to review each individual submission and provide detailed responses within the agreed timescales if all projects are submitted at the one time. By allowing different windows for different components, TOs and Ofgem can focus on the projects being submitted that year which will minimise any regulatory burden and ensure overall quality of submissions and responses can be maintained.

5.124 Again, as discussed in our response to Q12 of the Draft Determination – Core Document we see little advantage to placing the reopener window in January and see more benefits in a later window. See our response to Q12 for more detail on this topic.

5.125 Prior to submission of any scheme there needs to be a clear minimum information standard to ensure a decision can be made as soon as possible. This is of particular importance for connection schemes that do not have as clear a signal as NOA schemes for justification. These schemes will be of high value and can relate to more than one connection customer therefore it is imperative that a decision is reached quickly to allow the scheme to progress. Clear submission requirements need be outlined as part of the determination process for this mechanism and the other reopeners proposed for T2 and we seek further discussion with Ofgem on this issue.

<u>SPT Annex</u>

SPTQ17. Do you agree with our proposals for a re-opener covering these six non-load related projects?

5.126 We are pleased that Ofgem has recognised that our proposal protects consumers from risks associated with the uncertainties related to these projects. However, a single re-opener window late in the period is unnecessarily restrictive and places undue risk on the company as significant expenditure will be committed before Ofgem make a decision. Ofgem has accepted the need case and have full visibility of the solutions as they were foreseen at the time of the Business Plan submission. Therefore, the re-opener assessment will be limited to a review of costs and the solution only if they have changed since the Business Plan submission. This means that there will not be an excessive regulatory burden if more frequent re-opener windows are provided. We propose annual windows with a requirement for the company to notify Ofgem of its intent to submit a proposal 3 months in advance. This will provide sufficient time for Ofgem to plan its resources.

Chapter 6: Business Plan Incentive and Sharing Factor

Introduction

6.1 Despite the positive feedback on the quality of the Business Plan received from both SPT's independent User Group and the RIIO2 Challenge Group, Ofgem has imposed a penalty of £15m. The contrast between the range of rewards and penalties in the electricity transmission and gas distribution sectors (see Ofgem Draft Determination Core Document Table 15 page 123) calls into question the suitability of the BPI mechanism and in particular for the electricity transmission sector. Ofgem acknowledge (ET Annex paragraph 3.11) that the assessment of transmission costs is difficult and that there is a limited availability of useful data sets for comparison. It is therefore unsurprising that Ofgem have been unable to set their own benchmarks for a significant proportion of the asset costs in SPT's Business Plan which has in turn has resulted in BPI stage 3 penalties being applied. A mechanism relying on the availability of reliable comparators in a sector where Ofgem themselves state that there are few is therefore fundamentally flawed and has resulted in SPT being unfairly penalised.

6.2 In Ofgem's Business Plan Guidance ("BPG"), published on 31st October 2019, Ofgem state that they will "take into account the views of the Ofgem RIIO-2 Challenge Group and companies' CEGs and UGs in its assessment of Business Plans". There are no references to this in the Draft Determination and Ofgem have not published any details to communicate how they have taken these views into account. SPT's £15m penalty is not consistent with the views of the RIIO-2 Challenge Group or SPT's independent User Group.

High & Lower Confidence Costs

6.3 The influence of lower confidence costs on the Stage 3 penalty and stage 4 rewards is so significant that it calls into question whether when designing the mechanism, Ofgem anticipated such a high proportion of costs to be classified as lower confidence. On the assumption that there would be a natural range of outcomes for such a mechanism, we urge Ofgem to review the methodology such that high quality plans are fairly treated.

6.4 Ofgem state in the SPT Annex paragraphs 3.49 and 3.67 that SPT had not provided suitable independent cost information and that Ofgem do not have a suitable benchmark, which meant that costs were classified as lower confidence. In addition to the information provided in the responses to SPTL_SQ_CA_25 and SPTL_SQ_CA_42, Ofgem appear not to have accepted the provision (in Annex 23 of SPT's Business Plan) of the independent cost assessment report provided by Arcadis, a specialist consultant with extensive experience in this field. We note that the review undertaken for the exercise by SPT's specialist consultant was significantly more detailed and granular than the assessment Ofgem appear to have carried out, yet Ofgem have failed to take this report into account. In the BPG, Ofgem fail to define how they would assess costs as high or lower confidence. Despite the extensive evidence presented by SPT, had Ofgem transparently defined its cost classification criteria, SPT would have been able to present its evidence in a manner which was consistent with the criteria.

6.5 We welcome Ofgem's view that the majority of civil and non-unit costs are classified as high confidence. However, the reason why the remainder of costs in this category are not similarly classified has not been communicated. In bilateral meetings with Ofgem since the Draft Determination was published, we understand that Ofgem considered these costs to be sufficiently independently justified because we supplied our full, detailed Manual of Standard Costs in response to two of the Supplementary Questions (SQs) raised by Ofgem (SPTL_SQ_CA_25 and SPTL_SQ_CA_42). All other asset costs were similarly justified but Ofgem has not provided explanations for certain asset costs being classified as lower confidence.

6.6 Ofgem's lack of independent benchmarks results in a large proportion of asset costs being classified as lower confidence. We understand the lack of benchmarks in these asset categories to be the result of wide cost ranges in the assessment of asset unit costs. This is entirely due to the design of the Business Plan Data Tables ("BPDTs") and the definition of the unit costs in the Transmission Glossary v1.3 published by

Ofgem on 20 September 2019 (the "Glossary"). Some examples of this are set out below and we comment on this in more detail in Chapter 2 Expenditure & Outputs.

- When Ofgem engaged with network companies on the design of the BPDTs prior to the first draft submission of the Business Plan in July 2019, we highlighted in the issues log transmitted between SPT and Ofgem that the table designs were inadequate as they 'mixed' replacement and refurbishment costs. However, Ofgem appears not to have taken that feedback into consideration as the relevant parts of the table designs remained unchanged (please also refer to our response to question SPTQ12 in Chapter 2, Expenditure and Outputs).

- We also provided a scheme-by-scheme breakdown of the refurbishment elements of projects that had the potential to distort unit cost calculations in the commentary that was submitted alongside the BPDT (the "BPDTC"). Again, it is not clear whether Ofgem took account of any of SPT's feedback on this point.

- The Glossary does not sufficiently distinguish between materially different activities falling within the same unit cost definition. A good example of this is the asset category OHL (Tower Line) Conductor. The Glossary has a single entry per voltage but this asset can comprise single, twin, triple or quad configurations meaning costs can differ more than four times between schemes. This is before the capacity of the individual conductors, a further distorting factor, is considered.

6.7 Therefore, the inability of Ofgem to achieve a unit cost in many of the key categories is a direct result of their own decisions on BPDT design and Glossary definitions. This results in significant costs being classified as lower confidence. This is demonstrably irrational and unfairly penalises SPT at stage 3, impacts its ability to earn a reward at Stage 4 of the BPI, and unfairly supresses the sharing factor.

6.8 A further consideration in the requirement for costs to have historical comparators to be classified as high confidence is that innovative approaches or solutions being implemented as business as usual activities are penalised.

BPI Outcome

6.9 The table below summarises the components making up SPT's Stage 3 penalty.

Table 7: SPT's Stage 3 Penalty Components

BPI Penalty Element	BPI Penalty Value
Capex Modelling Errors & Inconsistencies	£6.18m
Projects Requiring Additional Justification	£4.77m
Risk & Contingency Reductions	£4.3m
Pre-Construction Funding Reductions	£1.39m
Total	**£16.64m**

6.10 The Stage 3 penalty contains elements that we have identified as erroneous. We have identified £100m of Capex modelling errors and inconsistencies in the Draft Determination (on which we provide further comments in the Chapter 2, Expenditure and Outputs section). Of this £100m, £61.8m contributes to the Stage 3 penalty, resulting in £6.18m of the penalty being applied erroneously. We have provided Ofgem with details of our calculation of capex modelling errors in the issues log in Appendix 2.

6.11 Risk and Contingency costs have been categorised as lower confidence and so are exposed to the BPI Stage 3 penalty mechanism. However, where Ofgem has established a benchmark, costs should be categorised as high confidence. Ofgem have cost assessed and effectively benchmarked Risk and Contingency costs and made reductions, as with asset unit costs. Therefore, these costs should be categorised as high confidence, removing £4.3m from the penalty. We note that Ofgem have acknowledged this issue and they have advised us via the issues log (Annex 2 of this response).

6.12 We also note Ofgem's Pre-Construction Funding proposal in the ET Sector document (also see our response to ETQ11) and that pre-construction funding may be sought via an alternative mechanism such as MSIP, as outlined in paragraph 4.55 of the ET Sector document (also see our response to ETQ11). In our view, the reduction in pre-construction funding has an erroneous impact on the BPI (£1.39m penalty), given that the cost has effectively been moved from the baseline to a UM, where costs can be assessed when projects and the scope of pre-construction activities are less uncertain. Therefore, pre-construction funding associated with NOA projects, or e.g. synchronous compensation projects (via our Net-Zero Operability UM proposal), that can be progressed via a UM, should be BPI exempt.

6.13 The remainder of the penalty relates to costs that have not yet been approved. As detailed in the Chapter 2, Expenditure and Outputs, additional evidence has been supplied to Ofgem in support of the approval of these costs. We remain of the view that these projects and their costs are justified, and this would result in the removal of the remaining £4.77m from the penalty.

6.14 Ofgem's erroneous approach to cost assessment results in SPT's Stage 2 reward of £1.6m being netted off, with an overall business plan penalty of £15m.

TIM Sharing Factor

6.15 As explained in the foregoing sections, SPT have submitted detailed evidence to support the categorisation of costs as high confidence which Ofgem have incorrectly categorised as lower confidence. This leads to a lower sharing factor (39.1%, Draft Determination Core Document paragraph 10.5) than would have been the case had Ofgem taken this evidence into account.

6.16 As noted in the Chapter 2, Expenditure and Outputs, SPT have submitted further evidence to support the approval of costs that Ofgem have rejected or not yet approved. Because of the erroneous categorisation of costs as lower confidence, the restoration of these costs will have the effect of further reducing the sharing factor; it is manifestly unfair that a greater proportion of costs being approved results in the weakening of the incentive.

Responses to Consultation Questions – BPI and Sharing Factor

Core Questions

Q34. Do you agree with our view that SHET, SPT, SGN and WWU passed all of the Minimum Requirements, and as such are considered to have passed Stage 1 of the BPI?

6.17 We consider that our business plan was high quality, well-structured and contained all necessary information to not only meet the minimum requirements but to transparently communicate all aspects of the plan to Ofgem and our stakeholders, a view supported by the RIIO-2 Challenge Group and SPT's independent User Group (please also refer to Chapter 10, Stakeholder Engagement). We therefore welcome Ofgem's decision that our plan passes Stage 1 but we have still been penalised by £15m.

Q35. Do you agree with our rationale for why NGET and NGGT should be considered to have failed Stage 1 of the BPI?

6.18 No response to this question.

Q36. Do you agree with our rationale for why Cadent and NGN are considered to have passed Stage 1 of the BPI?

6.19 No response to this question.

Q37. Do you agree with our overall approach regarding treatment of CVP proposals?

6.20 We do not support Ofgem's treatment of companies' CVP proposals. Ofgem did not set out how the CVPs proposed by companies would be considered and calculated until the September version of the Business Plan Guidance Document, less than one month before companies had to submit the second draft of their plans to the User Group and Challenge Group. As part of this, very little guidance was provided to companies as to how best to construe CVP proposals. SPT utilised a tool called a "Social Return on Investment" to present many of its CVPs. Ofwat has emphasised a shift to 'social value', a term Ofwat considers is equivalent to 'added value' as outlined in Ofwat's strategy. In addition, this tool has been supported by industry experts, however, we have been advised by Ofgem that this tool was not the best option for presenting CVPs.

6.21 Of importance is also the fact that 123 CVPs were proposed across the industry and the given that only 6 were accepted, this would further indicate that the expectations behind CVPs was not clear across all network operators.

6.22 Therefore, it is clear that Ofgem proposed an incentive for companies which could not fairly be achieved, as the goal posts were not set out transparently in advance of our submission.

Q38. Do you agree with our proposed clawback mechanism to treat received CVP rewards?

6.23 We agree with the principle that companies should not receive rewards for areas of non-delivery. However, for this to be fair and transparent, very clear rules will need to be established to ensure that companies are not unfairly penalised towards the end of the price control for discovering an alternative route for delivering a particular CVP. As CVPs themselves are not mechanistic, and no clear guidance has been provided for these, clear KPIs must be established and agreed with companies before Final Determinations. Companies cannot be expected to deliver something when no guidance or expectations have been established.

SPT Annex

SPTQ9. Do you agree with our proposals on the CVPs? If not, please outline why.

6.24 We believe Ofgem should re-assess our CVPs based on the evidence we provide below. This is due to the fact that since our Business Plan submission, we have received constructive feedback from Ofgem that our "Social Return on Investment" tool which was used for evaluating our CVPs was not deemed to be appropriate for evaluating our CVPs. As there was limited guidance provided on CVPs, and Ofgem only provided non-exhaustive high level guidance as to how CVP proposals would be assessed in September 2019 (3 months in advance of our December Business Plan submission), there was not sufficient opportunity for TOs to discuss the development of CVPs or to test these via workshops etc.

Revised CVPs

Net Zero Fund

6.25 As detailed within our Environmental Action Plan (Annex 7 of our Business Plan) on pages 109-112, our Net Zero Fund has been supported by a wide range of stakeholders and will deliver wider societal benefits of £3 for every £1 invested. Our £20m fund proposal does not include any associated SPT related works, such as engagement activities with stakeholders to determine key projects, or the funding of associated resources. Therefore, we had proposed a CVP for our fund. In our Business Plan we stated that consumers will realise £60m of benefits. We must clarify within this response that the £60m was not our proposed reward for this CVP. We strongly support our consumer benefits value of £60m, but in relation to any reward SPT would receive for delivering this consumer benefit, we consider it appropriate to recognise the additional costs to SPT of delivering this fund as a minimum. We propose that this value is 10% of the £60m benefits value with the TIM subsequently applied in order to ensure SPT is able to recover its costs associated with managing this fund.

6.26 As Ofgem did not recognise our Social Return On Investment (SROI) value of £3 for every £1 invested, we have presented the potential benefits from the fund below. We must recognise that as the fund is open to a wide selection of projects, we cannot accurately forecast the benefits in any case. However, we are confident that the fund will deliver a significant amount of wider societal and consumer benefit well above our CVP financial proposal which we can evidence as projects complete.

Table 8: Net Zero Fund CVP Benefits

	Description	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Cost	Cost of fund	£ 4,000,000.00	£ 4,000,000.00	£ 4,000,000.00	£ 4,000,000.00	£ 4,000,000.00	£ 20,000,000.00
Social benefits	Increase in human wellbeing from 1µg/m3 lower air pollution (NO2)	£ 2,769,060.00	£ 2,769,060.00	£ 2,769,060.00	£ 2,769,060.00	£ 2,769,060.00	£ 13,845,300.00
	Comfortable and warm homes reduces amount of illness cases	£ 3,500,940.00	£ 3,500,940.00	£ 3,500,940.00	£ 3,500,940.00	£ 3,500,940.00	£ 17,504,700.00
	Develop initiatives to reduce the environmental impact of Network company activities.	£ 304,000.00	£ 304,000.00	£ 304,000.00	£ 304,000.00	£ 304,000.00	£ 1,520,000.00
	Deliver a range of initiatives to attract young people to apply to work in the energy sector and develop the new workforce skills required to deliver smart networks.	£ 145,249.30	£ 145,249.30	£ 145,249.30	£ 145,249.30	£ 145,249.30	£ 726,246.50
	Have the network ready to accommodate Evs.	£ 580,422.45	£ 580,422.45	£ 580,422.45	£ 580,422.45	£ 580,422.45	£ 2,902,112.25
	Help fuel poor customers by providing efficiency and switching advice	£ 1,040,820.00	£ 1,040,820.00	£ 1,040,820.00	£ 1,040,820.00	£ 1,040,820.00	£ 5,204,100.00
	Engage with a range of community energy schemes looking to connect localised, small-scale renewable energy onto the electricity network.	£ 245.10	£ 245.10	£ 245.10	£ 245.10	£ 245.10	£ 1,225.50
	Increase in quality of life of customers	£ 3,394,110.60	£ 3,394,110.60	£ 3,394,110.60	£ 3,394,110.60	£ 3,394,110.60	£ 16,970,553.00
	Provide support to vulnerable customers who are also impacted by fuel poverty through a range of outreach support and advice services.	£ 875,235.00	£ 875,235.00	£ 875,235.00	£ 875,235.00	£ 875,235.00	£ 4,376,175.00
Total Benefit		£ 12,610,082.45	£ 12,610,082.45	£ 12,610,082.45	£ 12,610,082.45	£ 12,610,082.45	£ 63,050,412.25
Total Net Benefit		£ 8,610,082.45	£ 8,610,082.45	£ 8,610,082.45	£ 8,610,082.45	£ 8,610,082.45	£ 43,050,412.25

6.27 To demonstrate the consumer value which will be delivered from this fund, we have also created a dashboard of benefits to date from our existing Green Economy Fund in the figure below:

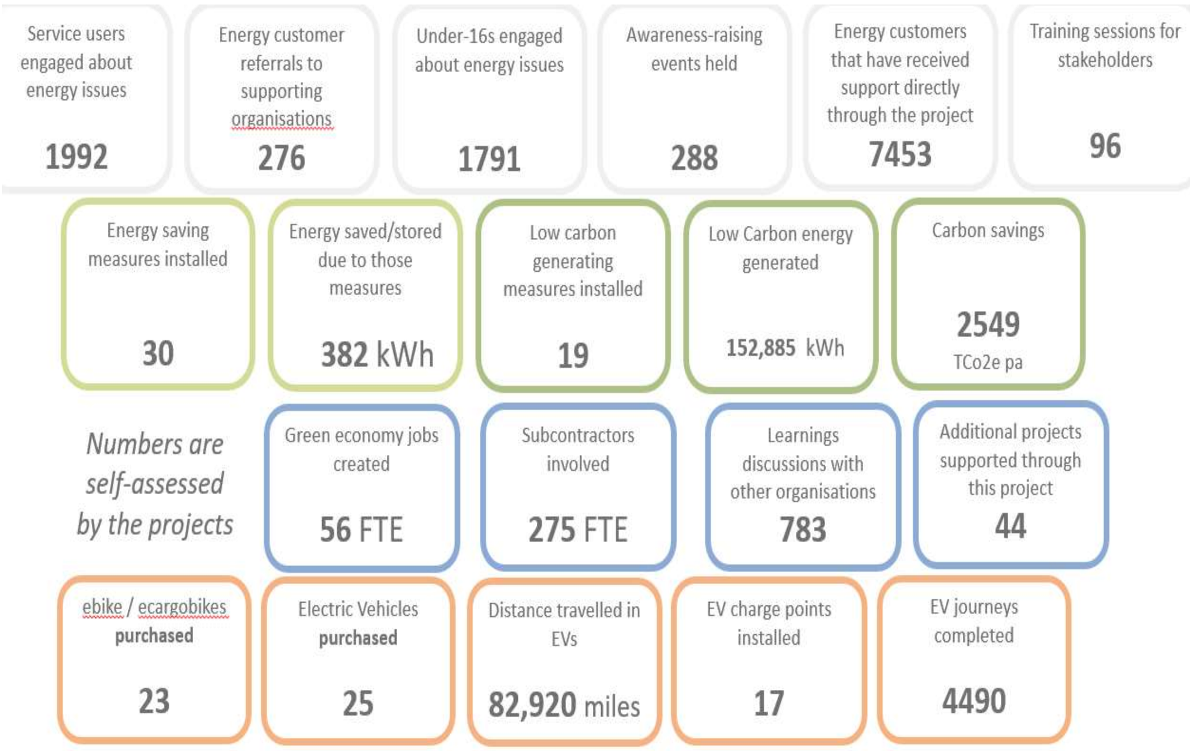


Figure 8: SPT's Green Economy Fund Benefits to Date

ENS Use it or Lose it Fund

6.28 In our Business Plan we proposed a bespoke Price Control Deliverable (PCD) for a "use it or lose it" fund to target reliability improvements for our distribution connected customers who are particularly exposed to network outages (sub-section 4.6.4 & 5 of Annex 12 of our Business Plan). This funding mechanism was supported by a reputational ODI to report Customer Minutes Lost (CML) and Customer Interruptions (CI) and test this approach as an alternative and workable approach to resolve the complex issue of embedded generation in the ENS calculation. This proposal is supported by extensive additional information and examples in Appendix 3 of Annex 12 of our Business Plan of how we have delivered ENS mitigation as a transmission business in RIIO-T1 for distribution customers.

6.29 Ofgem rejected this proposal (DD SPT Annex para 2.46-2.50) and we have addressed their concerns in our response to ETQ8. Following discussions in respect of the Use it or Lose it fund on 11th August 2020, Ofgem suggested that they recognised the merits of this proposal but did not consider it met the requirements for a PCD, so an alternative mechanism might be worth developing. Accordingly, we propose to develop a CVP proposal in respect of this fund and will submit this to Ofgem imminently for consideration within their Final Determinations.

SPTQ10. Do you agree with our consultation position to accept the maximise benefit from non-operational land CVP?

6.30 Yes, we welcome Ofgem's acceptance of this CVP as we agree it goes beyond BAU and will provide demonstrable consumer benefit. We will report progress in our Annual Environmental Report.

6.31 We would like to clarify some aspects of this project. Our commitment is to facilitate the access to land by local communities for environmental sustainability improvements. This could be for a variety of different types of land use such as the construction of community renewable energy projects or for biodiversity improvements (or both if possible) with the aim of maximising the environmental benefit from this land.

6.32 Our CVP proposal considered the provision of up to 20 of our sites. Taking the example of solar power, we calculated that such projects could deliver up to 4MW of renewable generation (based on the limit on MW capacity permitted for local community energy projects to be eligible for the associated funding mechanism). However, we are not prescribing this type of project. We will not have any control over:

- whether local communities choose to develop projects
- the MW capacity of any projects, which will be dictated by the local conditions, type of project and rules of the funding mechanism
- whether these projects receive the funding required to allow them to go ahead
- the timing of projects, including their funding, construction and commissioning timetables.

6.33 Our role will be to make sites available, to communicate this as widely as possible and thereby to provide a solution to the barrier frequently encountered by local community energy projects of a lack of access to suitable land at an affordable cost (in this case, no cost).

6.34 We therefore propose that, upon further consideration, a more appropriate metric of delivery of the aspects within our control (being access to the land) would be how many of the 20 proposed sites we have successfully granted access to local communities. The formula becoming: Return (£) = [no. of access agreements granted / 20] * CVP Reward(£).

Chapter 7: Incentives (ODIs)

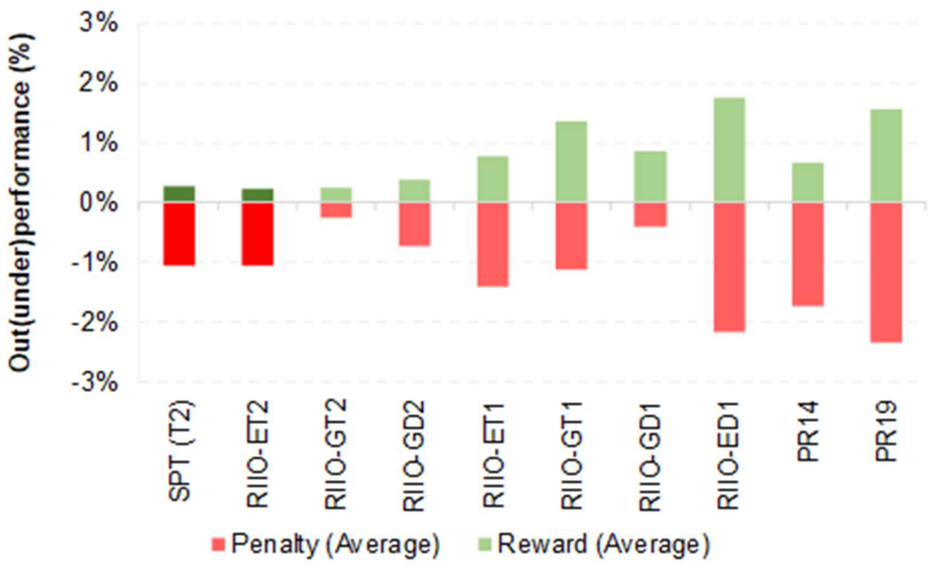
Introduction

7.1 The proposals Ofgem has set out in their Draft Determination for Electricity Transmission effectively remove incentives from its regulatory tool kit. As a strategic approach this reverses GB regulation in electricity transmission to rate of return regulation. In so doing, progress and improvement in network reliability, customer connections and service, innovation and environmental impacts driven by the output incentives of RIIO-T1 will slow down or go into reverse. **We have commissioned a report by NERA to compare Ofgem's proposed incentives package to other regulatory regimes; this report can be found within Annex 7 of this Draft Determination response.**

7.2 **SPT (and RIIO-ET2) incentives are downwardly biased, due to a negative skew towards penalties and a greater magnitude of the negative skew relative to other decisions.**

7.3 Ofgem proposes penalties 4 and 4.5 times higher than rewards for SPT and ET2 respectively, which is considerably greater than penalties for energy networks in RIIO-1 (penalties 1.1 times higher than rewards, i.e. almost symmetrical on average) or water companies at PR14 (penalties 2.6 times higher than rewards) and PR19 (penalties 1.5 times higher than rewards).

Figure 9: Ofgem's Proposed Asymmetry of Incentive Package for SPT/RIIO-ET2 Is Unprecedented Relative for UK Regulated Networks



7.4 For RIIO-GD2, Ofgem's Draft Determination also proposes an incentive package which is downward skewed, but the magnitude of the skew is less than half compared to Ofgem's proposals for SPT/ET (RIIO-GD2 includes penalties of up to 0.7 per cent, compared to rewards up to 0.4 per cent of RoRE on a common 55 per cent gearing basis, i.e. penalties around two times higher than rewards compared to around 4 times for SPT/ET2).

7.5 In contrast, Ofgem proposes a symmetrical calibration of incentives for RIIO-GT2, with rewards and penalties up to 0.25 per cent of RoRE (on a common 55 per cent gearing basis). Ofgem's proposals for SPT/ET2 are therefore downward biased both compared to RIIO-GD2 (negative skew more than 2 times greater for SPT/ET2) and RIIO-GT2 (symmetrical package).

Table 9: Ofgem's SPT and ET2 Draft Determination Proposals Are Disproportionally Biased Towards Penalties

	Penalty (Average)	Reward (Average)	Penalty-to-Reward
SPT	**-1.1%**	**0.3%**	**4x**
RIIO-ET2	**-1.1%**	**0.2%**	**4.5x**
RIIO-GD2	-0.7%	0.4%	2x
RIIO-GT2	-0.2%	0.2%	1x
RIIO-ET1	-1.4%	0.8%	1.8x
RIIO-GT1	-1.1%	1.4%	0.8x
RIIO-GD1	-0.4%	0.9%	0.5x
RIIO-ED1	-2.2%	1.8%	1.2x
PR14	-1.7%	0.7%	2.6x
PR19	-2.3%	1.6%	1.5x

Source: NERA analysis

7.6 The following table shows that Ofgem's approach is markedly different from European energy regulators where incentive regimes are more symmetrical:

Table 10: European Incentives for Energy Networks

Country (Sector)	Incentive Type	Penalty / Reward	Penalty-to-reward
Austria (GT)	Customer satisfaction	+5% of opex	Reward only
Spain (ET)	Availability	-3.5/+2.5% of opex	1.4x
Spain (ED)	Grid losses	-2/+1% of revenue	
	Supply quality	-3/+2% of revenue	
	Total	-5/+3% of revenue	1.7x
Finland (ET)	Quality	-3/+3% of return	1x
Finland (ED)	Quality	-15/+15% of return	1x
Finland (GT)	Quality	-2/+2% of return	1x
Ireland (ET)	System performance	-1/+0.5% of opex	
	Investment planning and delivery	-2/+2% of opex	
	Stakeholder	+1% of opex	
	Connection (ECP-1)	-0.5/+0.5% of opex	
	Strategic	Max EUR 2.5M, or +2.7% of opex*	
	Total	-3.5/+6.6% of opex	0.5x
Ireland (ED)	Worst-served customer	-0.3/+0.3% of revenue	
	Customer satisfaction	-1.6/+0.3% of revenue	
	Customer satisfaction survey	-0.3/+0.3% of revenue	
	Stakeholder	+0.1% of revenue	
	Connection (ECP-1)	-0.1/+0.1% of revenue	
	Interruption duration	-1.9/+2.1% of revenue	
	Interruption frequency	-1.9/+2.1% of revenue	
	Total	-6/+5.4% of revenue	1.1x
Ireland (GD)	Customer	-0.3/+0.3% of revenue	
	Growth (connection)	-0.5/+0.5% of revenue	
	Total	-0.8/+0.8% of revenue	1x
Portugal (ED)	Quality of service**	Max EUR 5M, or +0.6% of RoRE (common gearing)***	reward only

Source: CEER *(January 2020), Report on Regulatory Frameworks for European Energy Networks 2019 – Incentive regulation and benchmarking workstream, Annex 3 – Chapter 7; NERA analysis of regulatory decisions*

7.7 Output incentives are an integral element of the RIIO framework introduced by Ofgem in 2010 to build on the RPI-X focused regulation and drive improved customer service and the low carbon transition. This framework and the output incentives element in particular has achieved a step-up through the RIIO-T1 period achieving, for example, a 75% reduction Energy Not Supplied (ENS), 15% increase in Customer satisfaction and 99% success rate in Timely Connection offers as demonstrated within our annual reporting data to Ofgem.

7.8 Despite this track record of success, at the cusp of a decade where government, society and industry need to accelerate progress if the 2050 Net Zero ambitions are to be achieved, and a Green Recovery post COVID-19 supported, Ofgem has put the brakes on the transition to a decarbonised economy. Their Draft Determination has errors and flaws in its calculations, methodologies and policy perspective. For example:

- Ofgem has failed to recognise or understand, from the experience of RIIO-T1, that having the right incentives in place, in the right areas, delivers the best outcomes for consumers. They are wrong to assume existing output incentives that deliver improvement in one price control should necessarily become business as usual, baseline funded outputs in a subsequent price control.
- Ofgem is wrong in its view that new output incentives can only be justified when they are supported by historic evidence and that it is possible to set appropriate baseline targets.
- Ofgem is wrong in its view that incentives are only a reward or bonus for regulated companies delivering beyond minimum standards. Rather, it is our experience that they act as the driver to deliver this performance and effectively provide a funding mechanism to justify cost expenditure.

7.9 The overall performance seen in the RIIO-T1 output incentives demonstrates that in some areas (customer satisfaction for example), output incentives encourage network companies to prioritise and focus their organisational structure. They will seek to maximise their potential revenue available from the output incentive in return for delivering high levels of performance. Moving these areas from an output incentive to an efficiency incentive negatively changes the behavioural response of transmission operators (TOs) away from maximising its performance to reducing its expenditure. Even though the activities driving good performance have become business as usual, without proper output incentives the focus and priority will inevitably change and affect the outcome for consumers.

7.10 We have also seen in RIIO-T1 that areas of low maturity but high importance benefit from an output incentive to develop procedures, processes and associated metrics. For example, output incentives enable important low carbon areas like environmental sustainability, which may have little to no track record of activity or have significant uncertainty as to the future scope and potential to become established. These areas present opportunities for output incentives to drive development and progress towards being able to set prescriptive targets. Adopting an approach to output incentives that depends on a “SMART” methodology will lead to these areas being neglected for a full price control period. By doing this Ofgem is taking a step back rather than facilitating an acceleration in the low carbon transition compared to RIIO-T1.

7.11 Where there is inevitable uncertainty on the scope; frequency of incidence; level of expenditure in total (which varies on a case by case basis), an output incentive can be an effective and enduring funding approach instead of baseline funding. The reliability incentive targeting ENS and the bespoke output ODI for optimising network availability that we have proposed are good examples of this. The outputs we can deliver in these areas are subject to multiple variable factors throughout the price control period such as network configuration, site conditions, background system generation levels, etc. Funding them through ODIs provides a regulatory mandate to pursue and prioritise activities that will benefit customer and consumers but are difficult to forecast in terms of cost and volume. Effective ODI mechanisms can control the risk of unnecessary or inefficient revenues being recovered ensuring consumer value is protected.

Ofgem Has Effectively Removed ODIs from the RIIO-T2 Framework

7.12 Ofgem has not yet specified the full range of the output incentive package for the RIIO-T2 period, but from the available ODI information, we forecast (bottom up) that the output incentive range has a downside risk of £12.3m and a maximum upside opportunity of £2.3m per annum. This is compared to a downside of £12.7m and upside of £12.9m for the RIIO-T1 period. This asymmetric risk imposes an unreasonable liability on TOs. The extent of this asymmetric outcome is unprecedented in GB regulation and across international comparators[181] as we have explained above and presents a risk that will undermine investor confidence. Ofgem themselves[182] indicate the proposed range could be at 105bps downside and 27bps upside of RORE which translate to circa +£15.6m to -£61.8m over the price control.

7.13 The outperformance opportunity to achieve up to £2.3m is limited to the common ODIs of ENS, the Quality of Connections Survey (QofCS) and the Interrupting and Insulating gases (IIG) incentives. However, outperformance is severely limited because:

- the ENS incentive which drives network reliability has had its baseline reduced by over 60% compared to RIIO-T1, effectively reducing the allowance to invest in ENS mitigation by the same value.
- the QofCS is to be switched off for the full first year of the RIIO-T2 period and the baseline is yet to be determined but is likely to be higher than the RIIO-T1 level; and
- The IIG baseline for RIIO-T2 sets a disproportionate target, which will reward performance only when this exceeds manufacturers design specifications, which is beyond any network company's capability or responsibility to achieve.

7.14 Ofgem's own Impact Assessment[183] supporting their Draft Determination confirms this position and forecasts (paragraph 2.97) that, across all sectors, companies will achieve a zero reward/penalty outcome from output incentives over the RIIO-T2 period.

7.15 Furthermore, there are errors in the detail and approach that Ofgem has made in the methodologies and calculations it is proposing to use to set baselines in each of the common ODI proposals that remove almost all.

The Draft Determination is a Missed Opportunity

7.16 This Draft Determination proposals indicate Ofgem's approach to output delivery incentivisation has become confused and ineffective. We are disappointed that, as a result of this approach, Ofgem has rejected our ambitious output incentive proposals set out in Annex 12 of our Business Plan submission[184]. These proposals would deliver new areas of stakeholder engagement for a Net Zero system, reduce our carbon impacts, improve our customer connections and increase network reliability.

7.17 Ofgem are missing the opportunity our bespoke ODI proposals offer which is to introduce flexibility into transmission network operation and introduce a mechanism for measuring and improving reliability for generation connections.

7.18 Ofgem are also forfeiting the opportunity offered by the joint ESO/TO Constraint Mitigation proposal, put forward by all three onshore TOs and supported by the ESO (see paragraph 2.26 of the SPT Annex), which was presented to reduce the risk of high constraint costs associated with balancing services by millions of pounds for consumers. This is particularly surprising given the recent announcement of Ofgem's

[181] Ofgem RIIO-T2 Draft Determination - Incentives Calibration NERA Consulting August 2020
[182] https://www.ofgem.gov.uk/system/files/docs/2020/07/draft_determinations_-_finance.pdf
[183] https://www.ofgem.gov.uk/system/files/docs/2020/07/draft_determinations_-_impact_assessment.pdf
[184] https://www.spenergynetworks.co.uk/userfiles/file/RIIO-T2_Annex_12_Output_Delivery_Incentives.pdf

investigation into the ESO following an increase in constraint costs of £718 million 39% higher than expected, in March to July 2020[185]. We struggle to understand why Ofgem wouldn't use every potential tool available to them across the industry to look to reduce ever increasing constraint costs.

7.19 We are disappointed with the extent to which Ofgem has failed to justify their reasoning for dismissing each of the above-mentioned incentive proposals. None of the reasons Ofgem have put forward looks substantial, and they lack substance and supporting analysis.

7.20 We find the level of detail and weakness of argument frustrating given that the evidence we have submitted in our RIIO-T2 Business Plan to demonstrate that all ODI proposals fulfil the criteria set out in Ofgem's September 2019 RIIO-2 Business Plan Guidance[186]. In addition, in the ODI Annex 12 of SPT's Business Plan submission, we have demonstrated the positive NPV and consumer value proposition (CVP) that each of our financial ODIs brings. Importantly, each ODI is supported by, and intended to deliver on, the consumer, customer and stakeholder feedback we have received and used as the basis for our ODI proposals. This is laid out in more detail in Annex 12 of the SPT Business Plan and specifically in Appendix B: CONSUMER, NETWORK CUSTOMER & WIDER STAKEHOLDER FEEDBACK and Appendix C: OUR ODI COMMITMENTS.

7.21 Ofgem rejected 83% of the ODI proposals submitted across all ET, GT and GD submissions. This makes clear that either the guidance Ofgem set out to define ODIs, and the purpose and criteria ODIs were intended to address, was unclear or there is a broader policy issue regarding the value of incentive regulation for network companies. Either conclusion represents a fundamental failure by Ofgem to a failure to consider the price review as a package and the overall risk and return that it offers companies.

7.22 We are therefore deeply concerned that, if the Ofgem proposals to reject our bespoke financial ODIs are not reversed at Final Determination, a huge opportunity to drive forward network reliability, customer service and the low carbon transition will be lost for an entire price control period. We therefore ask Ofgem to reconsider their position in light of the evidence we provide in this response, work with us to overcome their concerns and identify appropriate mechanisms that can deliver the benefits these ODIs represent that they can include in their Final Determinations.

7.23 We would also ask Ofgem to review the baseline targets and methodologies they have proposed for the common ODIs and work with us to determine appropriate targets to include in their Final Determinations.

7.24 We must also make it clear that the proposed commitments set out in our Business Plan alongside each ODI are dependent on the ODI being awarded in RIIO-T2. It is our view that it is better value to consumers to reward companies through incentives as opposed to baseline funding which is why we have not included the relevant baseline funding to deliver these initiatives within our Business Plan. If the relevant ODIs are not accepted, SPT cannot deliver the associated commitments made within our Business Plan.

[185] https://www.ofgem.gov.uk/system/files/docs/2020/08/open_letter_spring_summer_review.pdf
[186] https://www.ofgem.gov.uk/system/files/docs/2019/09/riio-2_business_plans_guidance_september_2019_-_published_0.pdf

Responses to Consultation Questions – Incentives (ODIs)

ET SECTOR QUESTIONS

ETQ1. Do you agree with our proposals to switch off the incentive in year one of RIIO-ET2 in order to pilot the Quality of Connections survey and develop the baseline targets?

7.25 No, we do not agree with this proposal as it unnecessarily removes the primary customer focused incentive that supports the delivery of new low carbon connections and their ongoing operation for a full year of a five-year price control.

7.26 The connection of new low carbon renewable generation is fundamental to achieving low carbon targets and Ofgem's proposal strikes at the heart of this ambition. This decision will inevitably slow down progress of our ambitious customer commitments that we have set out in Table 7 of the ODI Annex 12, of our Business Plan. Each commitment in Table 7 is developed in direct response to customer feedback presented in that table. Ofgem's proposal to switch off the incentive for one year of a five-year price control does not reflect the importance this incentive has for customers and value it will bring to consumers.

7.27 Ofgem's proposal to switch off the incentive to run a pilot is not justified by their explanation in paragraph 2.32 of the Draft Determination Electricity Transmission Annex ("ET Annex"):

> "*the RIIO-ET1 baseline framework would not be representative of the survey scope that this incentive is intending to capture, and it is therefore not appropriate to use this data to calibrate the baselines for this incentive".*

7.28 This statement is flawed as it is only the survey mechanism that is changing, not the survey scope. The same connection customers surveyed in the RIIO-T1 period will be surveyed again and the same service provision – connection offer, delivery and outage management – will be assessed.

7.29 We therefore do not believe that it is necessary to conduct a pilot to establish a new baseline and believe this is not in customers or consumers best interests. We explain below our reasoning for this and a proposal to allow the pilot to be avoided and the incentive switched on in year 1, whilst resolving Ofgem's concerns.

Switching off the incentive for year one is contrary to Ofgem's decision set out in their RIIO-T2 SSMD published in May 2019, which states that:

> *"2.100 At this stage we are not making a final decision on the survey incentive strength or baselines (for the quality of connections survey) or survey design. We will continue to engage with stakeholders in the run up to Draft and Final Determinations ahead of reaching a final decision."*
>
> *"2.104 We will attach a financial reward and penalty to the connections component of the survey only. We will determine the financial weighting at Draft and Final Determinations."*
>
> *"2.115 We will reach a final decision on setting the survey baselines at Draft and Final Determinations."*

7.30 This proposal reduces the strength of the incentive for the price control period and removes it entirely for a full year. This will delay progress of the customer commitments we have set out in our Business Plan which respond to clear stakeholder feedback and priorities.

A pilot will not capture robust data to set a new and accurate survey baseline

7.31 We agree with Ofgem that running a pilot during the final year of T1 is not practical, but we do not agree a pilot is necessary or beneficial. A pilot would struggle to successfully capture statistically significant, robust data to set new baselines due to the time constraints and limited number of responses that could realistically be captured. Ofgem has indicated that the maximum consultation period for the pilot would be from April 1st, 2021 to the end of November 2021. Therefore, the number of opportunities to conduct surveys at all the proposed milestones will be severely limited.

7.32 For example, Milestone D: Project Delivery (as laid out in Appendix 2 of Ofgem's ET Annex) requires commissioning of a transmission connection project. Over the first six years of the RIIO-T1 period we connected 19 projects, which is an average of only 3 per year.

7.33 Over the same period, the total number of stakeholder satisfaction surveys received from customers of connection or connected projects (the same scope as the proposed quality of connections survey) was 112, an average of only 18 per year.

7.34 Given these low volumes and as Ofgem's proposed mechanism for the Quality of Connection Surveys are only triggered by a milestone being completed, there is significant risk of receiving insufficient data to set a robust in the pilot period.

7.35 In contrast, the baseline for RIIO-T1 was set after three years of evidence from across the three TOs[187]in August 2016. In this determination Ofgem recognised that this was a poor outcome:

"...we acknowledge that it is not ideal to set the incentive baseline value in year 3 of the price control. We've not been able to make a decision earlier in the price control because of a significant risk that it wouldn't be reliable or robust, which might lead to a poor outcome for consumers." (page 5)

7.36 Ofgem must not risk repeating this same outcome.

7.37 In the RIIO-T2 gas sector and ESO draft determinations, Ofgem has been able to set clear baselines and establish the incentive strength for the customer survey incentives. This is despite the fact in gas transmission Ofgem has also narrowed the scope of the incentive in a similar manner to electricity transmission yet have been prepared to use performance evidence from the RIIO-T1 period as explained in their SSMD of May 2019[188].

"We have decided to narrow the scope of the incentive, focusing only on NGGT's direct customers rather than customers and wider stakeholders. For this reason, we are minded reducing the strength of the incentive from 1 per cent of base revenue to 0.5 per cent of base revenue." Paragraph 2.46

"When this incentive was introduced in RIIO-GT1 very little data was available from which to benchmark appropriate performance targets. For RIIO-GT2, we expect to use actual performance data from RIIO-GT1 as the basis for setting performance targets." Paragraph 2.45

7.38 This leads to a better outcome for consumers and customers and a defined baseline and incentive strength should therefore also be set for the RIIO-T2 period and included in the Final Determination for electricity transmission. We have been collaborating with the other TOs and are engaging with Ofgem to identify a potential solution that resolves Ofgem's concerns and removes the need for a pilot, as we set out later in this section.

[187] https://www.ofgem.gov.uk/system/files/docs/2016/08/ss_output_decision_final_to_publish_4_aug_2016.pdf
[188] https://www.ofgem.gov.uk/system/files/docs/2019/05/riio-2_sector_specific_methodology_decision_-_gt.pdf

There is no methodology agreed with Ofgem to set the baseline or incentive strength

7.39 In their 2019 May SSMD Ofgem confirmed the Quality of Connections Survey incentive would be a common incentive, across all the three onshore TOs. Since then we have collaborated with the other TOs to develop a methodology (see appendix 2 of Ofgem's ET Annex) to develop a joint approach in line with Ofgem's proposals in their SSMD to establish a survey specifically focussed on the Connections process.

7.40 However, we still await engagement from Ofgem as to how the baseline and incentive strength will be calculated. It is therefore not clear how Ofgem will use the pilot survey to inform their decision on setting the baseline and the incentive strength (paragraphs 2.36 of the ET Annex).

7.41 Ofgem refer to (paragraph 2.37 of the ET Annex) the customer satisfaction surveys in the RIIO-GD2 and RIIO-GT2 as an example of the approach taken in other sectors. However, these are not supported by a documented methodology that could shed light on the approach Ofgem intend to take in electricity transmission. Of further concern, the value of the incentive strength for those surveys is set at 0.5% of allowed revenue. This is also the value Ofgem has applied in their licence model annex to the Draft Determination for our incentive. If it is indeed Ofgem's intention to move to 0.5% with respect to electricity transmission, this needs to be explained and justified by Ofgem.

7.42 In the absence of a clear methodology to determine the incentive strength and to set the baselines, and given the difficulties in achieving robust and statistically significant data volumes using a pilot survey, the proposal to switch off the incentive in year one and carry out a pilot is not justified and presents a risk that it is not in the best interests of consumers or customers.

The proposal does not reflect stakeholder feedback

7.43 This proposal to switch off the incentive for the first year of RIIO-T1 to undertake a pilot study was not consulted on in the December 2018 Sector Specific Methodology Consultation (SSMC). The stakeholder feedback informing the overall structure of this incentive was considered on the clear assumption this incentive would be in place for the full RIIO-T2 period. For example, Ofgem's May 2019 SSMD states:

"2*.152 We received 11 responses to our proposals in this area. There was broad agreement in response to these questions that there would be a benefit to capturing and incentivising improvements to the quality of the connection process though a stakeholder engagement survey."*

7.44 With the subsequent introduction of a one-year delay to the incentive in RIIO-T2 to accommodate a pilot, the basis of this stakeholder feedback provided is undermined.

7.45 Our own stakeholder engagement confirms strong support for this incentive. Appendix B of Annex 12 of our RIIO-T2 submission documents extensive, detailed feedback to support the importance of this incentive. For example, one wind farm developer states:

"Network companies have traditionally focussed on maintaining energy supply for end consumers. Current financial output incentives strengthen that focus. That is the right thing to do but what you've correctly identified is that are no incentives which drive network companies to proactively explore options to keep low carbon generation (which may be on single circuits by choice) on the network instead of interrupting the generator's export when the network is constrained."

7.46 Our User Group also support this incentive and in their final report state:

"The wording regarding "Quality of Connections Survey" has improved dramatically. The User Group has discussed and challenged the need to improve the quality of Connection Offers and to aim to get them right-first-time."

7.47 The Willingness to Pay (WtP) studies that we conducted throughout 2019 (see section 3.2.1 of Annex 12 of our Business Plan) identified the attribute "*Investing in infrastructure to connect renewable generation*" as a priority of 3 out of 9 for consumers. However, the proposal to switch off the incentive in the pilot year undermines the customer and consumer support to deliver improvements in renewable generation connectivity and risks slowing down the implementation of the commitments we have set out in our Business Plans for this area.

7.48 It is important for Ofgem to recognise that we have a set of clear commitments in our Business Plan that reflect customer feedback to be delivered under this incentive mechanism. A strong incentive, available at the start of the price control, will enable us to deliver these as quickly and effectively as possible for our connection customers. Without an incentive we will not be able to deliver these commitments.

7.49 We have calculated that this ODI, with its associated commitments, will support a net positive cost benefit analysis of £14.2m and consumer value proposition of £9.5m per annum[189]. For these reasons, we do not consider Ofgem's proposal to be in the best interests of customers or consumers and should be removed.

7.50 Instead we propose the following approach set out below for setting a baseline and confirming the incentive strength.

Our Proposal for setting the strength and baseline

7.51 Ofgem has proposed that it will consult on and set the incentive strength following the outcome of the proposed pilot survey. It is not clear what new information in the pilot, other than the changing baseline, will inform this decision. The focus of this incentive is to encourage improved service and satisfaction for connected parties. This is at the heart of the low carbon transition and the value of the incentive should reflect the importance and consumer benefits that this will provide for customers and consumers. The customer commitments we have made are significant and include:

- to build on our existing pre-application meetings and develop a range of pre-application connection engagement;
- to develop a digitised online connection portal to facilitate early stage analysis by customers, pre-application connection engagement, online application and ongoing project management from pre-application to post commissioning; and
- to provide earlier planned outage information, supplementing the formal processes provided to customers via the NGESO.

7.52 A strong incentive will allow us to invest time and cost into these new areas of development that will improve customer service levels for customers connecting and connected to our network. This contributes to the benefits consumers of up to £9.6m per annum as calculated through our CVP 7.1 (Annex 30 of our Business Plan) supporting this incentive.

7.53 A strong incentive will give a further clear signal for TOs to drive forward on Net-Zero ambitions to support the connection of low carbon renewable generation and retains the common baseline across the onshore TOs. It will also drive forward the connection of new low carbon renewable generation and support the operation of existing connections. Having the incentive in place from the beginning of the RIIO-T2 period will avoid the risk of delay to delivering our customer commitments and the risk of lower customer service.

7.54 Our proposal is that we will continue with a common baseline from RIIO-T1 in year 1. We will implement the new Quality of Connections Survey as presented in the Draft Determinations from April 1st, 2021. The incentive mechanism will be switched on from this date and reward will be based on the survey scores that we achieve over the year as normal.

[189] (See Table 5 of Annex 12 and CVP 7.1 of Annex 30 of our Business Plan submission).

7.55 However, we will agree a methodology with Ofgem that could adjust the baseline for the remaining years of RIIO-T2 based on the actual survey scores we achieve in year 1. Should the average performance across the TOs be above or below certain values, the baseline could be adjusted up or down accordingly.

7.56 For example, if the average score across all TOs is between 6.9 to 7.9 in year 1 there would be no adjustment to the baseline. If we score 8.1 then the baseline would adjust upwards by 50% of the difference between our score and the threshold (i.e. 50% x (8.1-7.9) = 0.1) so the baseline goes up to 7.5. This would preserve the incentive for year 1 and allow for an adjustment to our baseline by effectively running a live trial instead of a pilot.

7.57 We believe this will address the concerns Ofgem have presented in their Draft Determinations and avoid the risk to customer and consumers that switching off the incentive present.

7.58 We therefore recommend the incentive should be implemented from the start of RIIO-T2 and the incentive strength confirmed in the Final Determination and should be consistent with the values in RIIO-T1, i.e. incentive strength of 1% of annual revenue.

ETQ2. Do you have views on the common milestones, target audience and question of overall satisfaction for the Quality of Connections survey incentive provided in Appendix 2?

7.59 In general, we welcome the move to a focused survey of customers who are connecting or connected to the transmission network or are otherwise affected by transmission works. As detailed above, we have developed a common set of milestones (Appendix 2 of Ofgem's ET Annex) with the other TOs that provides for a common approach and the proposal for the target audience.

7.60 There could be challenges identifying embedded generation customers. Therefore, the survey must be limited to those customers we are able to proactively engage with. For example, it would be impossible to conduct surveys of all embedded generation customers, particularly as this would also overlap with current distribution network operator surveys.

ETQ3. Do you think there are any additional KPIs that have not been included in the final NAP which would support monitoring of performance in adherence to the NAP and/or add transparency of the outage planning, management and implementation process for relevant stakeholders?

7.61 The development of the KPIs was jointly achieved through close collaboration across the TOs and the ESO. The set of 11 KPIs introduced into the finalised version of the NAP reflects the activities and services TOs provide for customers in conjunction with the ESO. We believe they are a robust set of measures that will demonstrate the performance delivered by TOs to efficiently, effectively and economically coordinate planned outages on the transmission network and mitigate the impact of network faults that occur. We further consider that they are a comprehensive set of measures and additional KPIs are not required at this time.

7.62 On a broader policy point with respect to the NAP, we suggest there is an opportunity for Ofgem to align this key area of shared responsibility across the TO and ESO regulatory regimes. When comparing the detailed narrative and number of KPIs that the NAP provides to explain and measure TO performance in respect of outage management, it is surprising that the ESO has only one performance measure - "Short notice changes to planned outages" - to report in its framework as shown in Table 15 of the ESO Draft Determination Annex. This is measured by:

"*Number of short notice outages cancellations per 1,000 outages, due to ESO process failure*"

7.63 This highlights a lack of breadth in the accountability on the ESO in respect of their important role in operating the transmission system, which is also reflected in their licence, which only requires them to have a supporting obligation in respect of the NAP. This is a lesser responsibility compared to the extent of the TO licence obligation. A similar document to the NAP, with corresponding KPIs and service level commitments, should be mandated in the ESO regulatory framework commencing in RIIO-T2. We would suggest in the longer term that there should be a joint TO/ESO version of the NAP.

ETQ4. Do you agree with our proposed LPD mechanisms and do you agree with the criterion that we are proposing to use for our LPD mechanisms?

7.64 We do not support the Large Project Delivery mechanism in principle as we do not believe this to be in either companies' or consumers' interests for the following reasons:

7.65 The industry accepted approach for allocation of risk in project delivery and the contracts that govern these, is that the risk is allocated to the party best suited to manage it. In simple terms, this means that the main risk items related to projects which can be generally categorised as impacting time and cost, are agreed between the employer and the contractor. It is important to note that the allocation of risk in a commercial sense, neither comes for free nor is it underwritten by project margin/profit. This risk will be quantified by the party who agrees to take that risk as an additional overhead and will include this assessment in the contract price. In summary, the employer (i.e. the licensee) will pay for the transfer of this risk to the contractor.

7.66 The costs of the risks being borne by a contractor will be included as an overhead and ultimately in the contract price. No sensible contracting party will underwrite the cost of risk from their project profit margin or at a corporate level i.e. putting their balance sheet on the line. It follows that the employer, in this case SPT as funded by and on behalf of the UK consumer, will require to pay for the transfer of risk, irrespective of whether the risk crystallises or not. On specifics such as costs of delay, which are generally governed by liquidated damages as a percentage of the overall contract price, these again will be included in the contract price that is accepted via the tender process. These costs are not absorbed by the contractor, therefore the larger the risk transfer and more aggressive the liability regime, the higher the contract price. It is clear that a balance must be struck on this as if the risk is not capped or an alternative outcome cannot be provided, then the contractor market will simply be artificially inflated, and costs will rise. A comparison could be made with the obtainment of insurance – how much risk can be sensibly managed and how much should be transferred to be covered. The more that is transferred the more that it costs.

7.67 It remains unclear as to the basis for the delay charges that Ofgem proposes to place on the TOs. This must relate to a genuine pre-estimate of loss considered likely to be incurred by a party should the delay materialise. It must therefore be quantified upfront. If Ofgem, however, consider that that this risk should be passed ultimately to the party who can best manage this (i.e. the contractor) then it becomes a potentially high value item that will increase contract prices. In turn, this cost would be borne by the UK consumer.

7.68 Ofgem will require to provide a framework of risks that it believes are within the grasp and ability of the TOs to manage. Certain delays cannot be passed on, irrespective of the delay, since the delay is due to events outwith the TOs/ contractors' control – for example, force majeure events, ground conditions, extreme weather conditions and industry-wide standard contracts typically carve these out of contractors' responsibility – therefore Ofgem will need to take cognisance of this. Ofgem's framework would also need to take account of the standard approach in construction contracts to (and the wider approach to liability in relation to) delays, concurrent delays and consequential delays. Equally, consideration needs to be given to when a delay results in no financial harm to any party – how will Ofgem make that assessment and what mechanism/procedure will be used to confirm up front the costs of delay and will this methodology be subject to external review.

ETQ5. What are your views on applying our LPD mechanisms to some or all of the projects identified at paragraph 2.74?

7.69 It is our view that the Late Project Delivery mechanism should not be applied to any projects for the reasons provided within ETQ4.

ETQ8. Do you have any views on our outputs that have not been covered through any of the specific consultation questions set out elsewhere in this chapter? If so, please set them out, making clear which output you are referring to.

7.70 We do have views on a number of the other outputs as follows:

Energy Not Supplied (ENS)

7.71 Ofgem's approach to incentivising reliability has evolved since the early 1990s. The RIIO-T1 incentive is a strong broad-brush mechanism that has delivered high levels of reliability for customers and consumers compared to previous price control periods. However, this incentive is experiencing difficulties in keeping up with the rapidly evolving nature of the transmission system and must evolve for the RIIO-T2 period. We are disappointed that Ofgem has not taken the opportunity, to introduce the range of proposals we have set out in section 4.6 of Annex 12 of our Business Plan submission. These proposals build on the success of the incentive in RIIO-T1 and improve the incentive mechanism to deliver consistent or better levels of reliability for consumers and resolve issues arising out of the low carbon transition.

7.72 Specifically, our proposals would:

i. Maintain a strong incentive to drive our long-term system design and asset management to achieve equal or better reliability to our customers and consumers even as the transmission system evolves and becomes more complex to deliver Net Zero goals.

ii. Deliver a more targeted approach to mitigate the risk of ENS for our distribution customers and consumers and to reflect the changing nature of the electricity system. It would also trial a methodology that resolves the issue of embedded generation that is undermining confidence in the value of ENS as a measure of transmission network reliability.

iii. Broaden the incentive to encompass generation connected customers as well as demand connected customers. This would provide an incentive to improve service for generation customers whilst increasing the volume of low carbon energy coming onto our network than would otherwise be the case.

7.73 Ofgem has rejected our bespoke ODIs which would have made the ENS incentive mechanism more inclusive by introducing a reliability measure for connected generation by targeting distribution connected customers, not just transmission connected customers, and by trialling alternative metrics that could resolve the impact of embedded generation on the ENS metric.

7.74 In addition, Ofgem proposes to reduce our annual ENS baseline target from 225MWh to 86MWh. This effectively reduces the level of investment in mitigating actions we can make to reduce the risk of ENS compared to our RIIO-T1 position by over 60%. The methodology and data Ofgem to calculate this baseline is flawed and needs to be corrected. We believe our target should be 133MWh if the appropriate ENS data is applied.

7.75 Ofgem's decision to reduce our target by over 60% from RIIO-T1, effectively reduces the level of investment that we are able make in mitigation of ENS events by the same level. We forecast this would amount to a reduction by almost £2million per annum. This seriously puts at risk the level of reliability that consumers and customers expect and that we were able to deliver of the RIIO-T1 period.

7.76 We therefore call on Ofgem to work with the TOs to identify a fair and appropriate baseline and resolve the objections they have made to our bespoke ODI proposals, in order to bring the benefits and value these proposals offer to customers and consumers.

7.77 We explain our position on ENS in more detail as follows:

Our comprehensive approach to ENS

7.78 In our Business Plan submission, we proposed a lower overall baseline of 178MWh (from our previous RIIO-T1 baseline of 225MWh) supported by a collar of 1.9% (down from 3% in RIIO-T1) which would hold us to account for the impact of no supply events whilst driving our long term design and asset management to deliver a complaint network (sub-section 4.6.3 of Annex 12 of our Business Plan).

7.79 We proposed a bespoke ODI to Optimise Network Availability for Connected Generators which would have broadened the ENS incentive to include generation connections for the first time. ENS is currently only measuring performance in reliability for demand connections not generation connections. This ODI proposal would have improved and broadened the ENS scope to introduce Network Availability as a measure of reliability for generation connections. This better reflects the low carbon electricity system as it exists now with multiple disaggregated generation compared to the few very large generation connections that provided energy in the past. This proposal moves ENS incentive forward for the Net Zero system of the future.

7.80 We also included a proposal for a bespoke Price Control Deliverable (PCD) for a “use it or lose it” fund to target improvement reliability for our distribution connected customers who are particularly exposed to network outages (sub-section 4.6.4 & 5 of Annex 12 of our Business Plan). This funding mechanism was supported by a reputational ODI to report Customer Minutes Lost (CML) and Customer Interruptions (CI) and test this approach as an alternative and workable approach to resolve the complex issue of embedded generation in the ENS calculation. This proposal is supported by extensive additional information and examples in Appendix 3 of Annex 12 of our Business Plan of how we have delivered ENS mitigation as a transmission business in RIIO-T1 for distribution customers.

7.81 These proposals are supported by an NPV of £11.8m and Consumer Value Proposition of up to £6.5m per annum (sub-section 4.6.8 of Annex 12). Our proposed baseline of 178 MWh presents a limited reduction in the incentive strength which will change the risk-based weighting to a level that reflect the efficiencies we have embedded within our ENS process throughout RIIO-T1.

Ofgem's limited response

7.82 We are not convinced that that Ofgem has considered our comprehensive approach to enhancing and improving the reliability incentive. Their response to this comprehensive approach addresses each of our bespoke proposals individually and does not consider them as a whole and the interactions that exist between them.

7.83 We have also identified other shortcomings in Ofgem’s response to our ENS proposals as we explain below.

Ofgem has not used appropriate values of ENS to calculate our baseline

7.84 Paragraph 2.10 of the SPT Draft Determination Annex explains that Ofgem has used a weighted average methodology to set baseline targets for RIIO-T2.

7.85 Ofgem has not used appropriate values of ENS to calculate our baseline of 86MWh and have therefore made an error. The values of ENS which Ofgem have used are taken from the Regulatory Reporting Pack (RRP) we submit on an annual basis. However, for the period of 2005/06 to 2012/13 we were required to report two sets of values for ENS in table 4.3 of our RRP. The first set of values included all events where unsupplied energy occurred. The second set of values excludes events involving fewer than three customers.

7.86 The current ENS methodology and incentive rules, which will apply in RIIO T2, would include ENS events with three or less customers and this rule should be applied to the calculation of the baseline. We therefore propose that our baseline for RIIO-T2 should be recalculated with the ENS associated with three or less customers included. This would set our baseline for RIIO-T2 at 133MWh using the weighted average methodology Ofgem average propose.

7.87 The impact on our ENS target against our RIIO-T2 baseline is a 62% reduction compared with a 53% reduction for NGET and a 15% reduction for SHE transmission. We strongly believe this methodology leads to an unjustified and unequal outcome compared to the others TOs and effectively penalises SPT for our good performance in RIIO-T1. While the supporting annex that Ofgem provides includes helpful analysis, Ofgem do not provide any justification that the weighting used by Ofgem provides an appropriate baseline for each company which will support the high levels of reliability that customer and consumers expect.

7.88 Ofgem's methodology only takes into account historic performance and this does not consider the future network which is evolving rapidly. Therefore, achieving the same levels of ENS performance will involve different challenges and risks including the increasing loss of inertia, disaggregated generation and an ever-increasing volume of work requiring planned outages. Historic performance is therefore not necessarily reflective of future performance.

ENS use it or lose it fund

7.89 We explained that our proposal for a "Use it or Lose It" fund (section 4.6.4 & 5 of Annex 12 of our Business Plan) is intended to drive our short term ENS mitigation actions associated with our essential planned outages. This complements the main ENS incentive and provides a more targeted and accountable approach to develop the RIIO-T1 ENS mechanism. This is because it provides a dedicated funding mechanism to support distribution customers who are particularly exposed to ENS risk from our transmission outages, supported by appropriate metrics and annual reporting.

7.90 Ofgem argues in the SPT Draft Determination Annex that this Use it or Lose it fund (Energy Not Supplied (ENS) Ring Fenced UIOLI Funding, Table 11) is not *"an appropriate, efficient, or proportionate policy solution to address the difference in design characteristics of the Scottish transmission network."* This limited explanation indicates Ofgem has not recognised the reasoning we have presented in our Business Plan (as detailed above) which led to the development of this proposal.

7.91 In paragraph 2.47 of the SPT Annex, Ofgem attempts to justify its rejection of this proposal by suggesting that the risk of loss of supply events for distribution customers is limited to the 132kV network. This is inaccurate as our network also consists of 400kV and 275kV grid supply points (GSPs) supporting major centres of distribution demand. Ofgem then goes on to state that we can continue our good practices of RIIO-T1 without additional funding. However, this position is clearly inconsistent with the established regulatory framework which obligates Ofgem to fund licensees to enable them to fulfil their licence obligations.

7.92 In paragraph 2.48, Ofgem claims we have failed to provide robust evidence to support our ENS proposals in terms of whether ENS is increasing for distribution customers, whether the £1.5m funding pot is appropriate and if our proposal is supported by customers and stakeholders. We would like to take this opportunity to highlight key elements of our Business Plan submission, where we provide robust evidence to justify our proposals. In paragraph 4.6.4 of Annex 12 of our Business Plan, we explained that as a result of the volume of essential planned work we have undertaken on our transmission network throughout RIIO-T1, up to 500,000 distribution customers could be at single circuit risk every week. Up to April 2018 our ENS performance achieved an average of 15MWh from 21 transmission loss of supply events. Of these incidents, 16 affected the distribution network with over 300,000 customers suffering a loss of supply. The average CMLs associated with these events was 64 minutes per year.

7.93 In Appendix 3 of Annex 12 of our Business Plan submission entitled "ENS Methodology and Risk Mitigation Examples" we provided examples of three RIIO-T1 projects which provide details of the types of mitigation actions we have invested in during RIIO-T1 to limit the impact on distribution customers and deliver this level of performance.

7.94 We believe these examples are sufficient to clearly demonstrate the extent of the exposure distribution customers have in respect of outages on the transmission network. As we highlighted above, the future network risk is increasing as we deliver the Net Zero network. The outages we will require in RIIO-T2 will be unique and involve different network configurations and customer impact. Each outage will be assessed on a case by case basis. The cost of mitigation is uncertain and not necessarily reflective of historic costs. This is why we have proposed a Use it or Lose it fund with a capped value that would provide a level of investment equivalent to level provided under the RIIO-T1 incentive, in conjunction with the proposed baseline value of 178Mwh. This value was on average a maximum of £3.6m per annum.

7.95 Our "Use It or Lose It" fund proposal would provide a targeted mechanism to maintain and improve network reliability for up to 2 million distribution connected customers. This would also act as a trial to establish reporting procedures and business processes to enable a more informed target to be set for RIIO-T3. It would also provide a test of an alternative approach to the inclusion of embedded generation into the ENS calculation by using CML and CI as an alternative or additional measure. Ofgem rejected this proposal (DD SPT Annex para 2.46-2.50) and we have addressed their concerns in our response to ETQ8. Following discussions in respect of the Use it or Lose it fund on 11th August 2020, Ofgem suggested that they recognised the merits of this proposal but did not consider it met the requirements for a PCD, so an alternative mechanism might be worth developing. Accordingly, we propose to develop a CVP proposal in respect of this fund and will submit this to Ofgem imminently for consideration within their Final Determinations.

7.96 The third element of our ENS proposals was a bespoke ODI for "Optimising Network Availability for Connected Generation." This is laid out in paragraph 4.6.6 of Annex 12 of our Business Plan. Ofgem have rejected this proposal and the explanation is limited to that set out in Table 10 of the SPT Annex. We address this in our response to question SPTQ1 below.

Value of Lost Load (VoLL)

7.97 We agree with Ofgem's current position (paragraph 2.15 of the ET Annex) that there is no significant evidence to propose a change to the value of lost load (VoLL) at this time, other than to amend its price base to 2018/19 prices.

7.98 However, Ofgem proposes (at paragraph 2.16 of the ET Annex) to include in the ENS Licence condition a mechanism for the VoLL value to be amended during the RIIO-2 period.

7.99 We fundamentally disagree with the proposal that VoLL should be amended during a price control period as it re-opens the financial package causing uncertainty for consumers and investors alike as well as the network companies. Any change to VoLL should be consulted on as part of the Draft and Final Determinations and set for the full price control period.

Financial collar on penalties

7.100 Ofgem proposes to retain 3% of Base Revenue as the financial collar for penalties (paragraph 2.21 of the ET Annex). Annex 12 section 4.6.3 of our Business Plan submission includes a proposal and justification for amending the collar to 1.9% to reflect the reduction in the price control period from 8 to 5 years. Our proposal is in line with the rationale that Ofgem used in their initial decision to apply a 3% value for RIIO-T1 that considered the ability for the TO to recover from a large-scale event through the period.

7.101 Ofgem's proposal presents an asymmetric risk with a significant downside that presents an unreasonable liability for TOs.

Taking account of embedded generation in the calculation of the ENS metric

7.102 Ofgem proposes to establish an industry working group (paragraph 2.25 of the ET Annex) to develop a way to include embedded generation in the calculation of the ENS metric for RIIO-ET3. We refer to Section 4.6 of Annex 12 of our Business Plan that explains our views on the challenges of incorporating embedded generation in the ENS calculation. We propose using CML and CI as alternative measures to ENS. Our Use it or Lose it fund described above, includes a proposal to measure and report on CML and CI and a baseline from RIIO-T1 period for these metrics.

7.103 The proposed working group should therefore not be limited to incorporating values embedded into ENS generation as the only solution to provide an effective measure of reliability but should also consider our proposals to measure and report on CML and CI.

Updating ENS incentive methodology statements

7.104 Ofgem proposes that we update our ENS incentive methodology statement by the 31st December 2020 and incorporate milestones and key deliverables (paragraphs 2.26 and 2.27 of the ET Annex) to develop and implement a methodology in RIIO-T3 that takes account of embedded generation in the ENS metric.

7.105 This proposal is not realistic. We would highlight this is a joint methodology shared by the three TOs. Therefore, co-ordination and collaboration would be required to update this methodology statement and maintain it as a joint document. Such a document should also reflect the licence conditions that will be in force during the RIIO-T2 period.

7.106 Further, the level of granularity required to give effect to the milestones and key deliverables proposed by Ofgem is both unreasonable in terms of timescale and impractical given that the relevant licence conditions for RIIO-T2 will not be in force by the 31st December 2020. The existing ENS methodology makes significant references to the existing licence and we expect the revision to be informed by the ENS licence condition for RIIO-T2. The ENS methodology should therefore only be amended after the introduction of the new licence condition coming into force.

7.107 We recommend that Ofgem revises this timeline accordingly and proposes a date of three months after the ENS licence comes into force.

Conclusions on the ENS incentive

7.108 The level of performance the ENS Incentive achieved in RIIO-T1 was to reduce average ENS to approximately 19MWh (see section 4.6.1 of Annex 12 of our Business Plan). In our Business Plan, we provided clear evidence of customer and stakeholder support in addition to evidence of willingness to pay by consumers supportive of continuing this impressive level of reliability. We must also note that today's performance is not reflective of future performance due to the evolution of the electricity system, which has more non-synchronous generation connecting etc, making the system more challenging to manage than ever before.

7.109 We provided in Annex 12 of our RIIO-T2 Business Plan a significant amount of evidence to Ofgem to explain how we can improve on the ENS incentive to deliver equal or improved levels of reliability for customers and consumers, whilst continuing to deliver good value for consumers through the inclusion of a 'use it or lose it' fund.

7.110 Ofgem's proposals for the ENS mechanism for RIIO-T2, as they stand, present a significant risk that reliability for customers will be reduced for the RIIO-T2 period and should be amended in line with the proposals we have set out in our Business Plan.

Insulation and Interruption Gas (IIG) leakage incentive

7.111 Ofgem confirms in paragraph 2.102 of the ET Annex that SPT's commitment to procuring assets with a leakage rate that is half that of typical manufacturers' guaranteed leakage rate (i.e. 0.25% instead of 0.5%) sets a new benchmark for best practice.

7.112 Yet their decision to set the IIG leakage incentive baseline target using the average leakage rate from 2013-20, with a 15% improvement factor applied (paragraph 2.126 of the ET Annex), is an unreasonable target and is likely to result in a penalty over the RIIO-T2 period, even if we deliver performance in line with manufacturers design specifications.

Ofgem's methodology and approach for setting our baseline is flawed

7.113 Ofgem has not consulted on this and has deviated from the three options they proposed for setting the IIG baseline in their May 2019 SSMD. We would urge Ofgem to clearly set out the methodology and justify how a 15% improvement factor for all TOs has been appropriately calibrated, and how this is reasonable and in consumer interests.

7.114 Ofgem's proposed methodology to use the actual average performance over the RIIO-T1 period to set our starting baseline for RIIO-T2 is not appropriate. This approach does not allow for the two key factors that affect our leakage rates. These factors are:

i. The threefold increase in our Sf_6 asset inventory over the RIIO-T1 period which has risen from 55349 kg in 2013/14 to 113545 kg in 2019/20[190]

ii. The actual leakage rate of 1.45% of our pre-RIIO-T1 assets

7.115 These factors have a significant bearing on our future leakage rates. The SF_6 assets added during RIIO-T1 do not require top up during the early years of their life and therefore do not contribute to our actual average emissions in this period. But they do contribute to the leakage rate leading to an unrealistic measure of average leakage over the period. In future years they may require top up whilst still leaking within their design specification. This would result in the baseline value set by Ofgem using average actual leakage as unrepresentative for future emissions performance.

7.116 The actual leakage of our pre-T1 assets exceeds that of our RIIO-T1 baseline of 1.22%. This reflects the range of assets introduced over a number of years, with higher design specification (typically 3%) which are ageing and now requiring top ups in line with their design specification. SPT are committed to taking mitigation measures to reduce these emissions where these are technically and economically feasible, but by their approach to setting the baseline based on actual leakage Ofgem miss this factor and undermine the accuracy and appropriateness of the baseline.

7.117 By calculating our T2 baseline on an actual average leakage as Ofgem have proposed and by adding a 15% improvement factor, Ofgem have failed to take account of the factors described above and are setting an unrealistic baseline, which could lead to penalties for emissions that are in line with manufacturers design standards in the RIIO-T2 period and beyond. This undermines the purpose of the IIG mechanism, which is to incentivise network companies to reduce leakage of IIGs from their networks and not penalise them for achieving minimum design standards.

7.118 We do not believe this is Ofgem's intention and they should revise this proposal. The use of actual performance data to set the baseline does not take account of the increase in SF_6 inventory. It is not clear how the adoption of a 15% improvement factor, as an overlay to actual performance has been determined as appropriate or justifiable. We would also highlight this proposal has been arrived at with no input from manufacturers, network operators or other stakeholders to test its merits.

7.119 The use of a symmetrical target for the incentive, when based on actual performance, is not reasonable. We are committed to delivering the tightest SF_6 leakage specification and we believe we have demonstrated this by investing for the Green Economy during RIIO-T1, by supporting the high growth in renewable generation and by procuring the best technical and most economic solutions that are available from the market. A reward for performing better than this is reasonable. However, a penalty for performing worse than target must take account of the technical capabilities of equipment. and the original design specification for the leakage rate. As a result, any penalty should only apply when the actual leakage exceeds the design performance of the appropriately installed switchgear. In light of this it would be pragmatic, reasonable and fair to both consumers and TOs, to adopt an alternative approach as we outline below.

Our proposal for setting the baseline

7.120 The RIIO-T1 baseline set at 1.22% presents a proxy for the average manufacturers design specification for those assets. It is a challenging but realistic target. The manufacturers design specifications of 0.5% for indoor and 1% for outdoor have been applied to the assets added during the RIIO-T1 period to adjust the year on year baseline target. These again set an appropriate baseline for that period. For RIIO-T2 we propose that the international standard for SF_6 of 0.5% and 1%[191] for all other IIGs is the appropriate value to set a baseline for all IIG assets added in this period. Future periods should continue to align with

[190] Ref Table 6.5 RRP 2019/20
[191] IEC 62271-1 High-voltage switchgear and control gear – Part 1: Common specifications for alternating current switchgear and Control gear

international standards as they evolve. This approach incentivises network companies to drive manufacturers to achieve higher standards of emissions as we have been doing.

7.121 We recognise that Ofgem has not yet been able to include the 2019/20 SF_6 values from our most recent regulatory reporting submission in July 2020 due to the timing of their Draft Determination publication. We would ask that these values now be incorporated into its baseline calculations.

Impact of the global warming potential of IIG on the incentive

7.122 There are currently 7 dielectric gases, including SF6, available for use within high voltage apparatus. They all have varying levels of Global Warming Potential (GWP) from 0 to 23500. Three have GWP of less than 1 the others have values of 300 and above.

7.123 The market for modern SF_6 free equipment is relatively immature at 132kV and above and is currently dominated by three large manufacturers. It is likely that other manufacturers will begin to produce SF_6 Free equipment either developing their own gases or adopting one of the already established solutions. It has been SPT's experience, so far, that as the new gases are applied to different applications, performance issues are identified which requires the gaseous combinations to be modified. It is probable that as higher voltage applications are developed different gas combinations will be required.

7.124 SPT is committed to installing SF_6 Free equipment where this is viable. We have been early adopters of SF_6 free equipment, and as such will manage a combination of gases going forward. It is the view of SPT that gases with a GWP greater than 0 (zero) should continue to be recorded as part of our gaseous inventory, however, we question the validity of gases with a GWP less than or equal to 1 (one) being included in the IIG incentive.

7.125 It is the duty of SPT as a responsible TO to ensure our equipment continues to be in a serviceable condition which includes keeping gas levels at operational levels and repairing leaking equipment. The IIG incentive is designed to drive continuous improvement in gas tightness from the TOs to reduce the global warming impact of their activities. This continuous improvement is critical in the strive to Net Zero particularly when considering the high GWP values of some dielectric gases.

7.126 The SPT RIIO-T2 Business Plan defers the addition of 9700 kg of SF_6 from equipment by utilising SF_6 free alternatives. When reviewing the IIG incentive we have considered the implication of leakage of gases with a GWP less than or equal to 1. We have calculated that if all our SF_6-free equipment in RIIO-T2 had a GWP of 1, had a design leakage rate in line with international standards of 1% and had an actual leakage rate of 5%, our penalty in any year would be £18.00 (eighteen pounds). We also calculated using the same criteria but with an inventory of 100,000kg the resultant penalty which would be £192.00 (one hundred and ninety-two pounds).

7.127 It is the view of SPT that due to the minimal penalty or reward that can be gained from gases with a GWP less than or equal to 1 they should be excluded from the IIG incentive, as the costs associated with administrating the associated Ofgem reporting would outweigh any benefits. We will record these gases in our inventory and repair leaks as and when they occur. This approach is complementary to the condition regarding exceptional events, where these can only be claimed by the TOs, if they can demonstrate the cost of administration of the claim is less than the associated penalty of the gas lost.

7.128 There has also been some confusion as to the GWP for SF_6 that should be used. The ET Annex (paragraph 2.123) quotes a GWP for SF_6 as 23,900 times stronger than CO2. This value was also required in our Business Plan Submission (Table A6.5) and the RIIO-T1 SF_6 licence condition. In contrast, the Business Carbon Footprint (BCF) RIGs require a value of 22,800. We propose that a value of 23,500 is now in line with latest accepted standards[192] and should be used for all regulatory reporting.

[192] AR5 -the fifth Assessment Report (AR5) of the United Nations Intergovernmental Panel on Climate Change (IPCC) finalised in 2014

Conclusions

7.129 On this basis Ofgem should:

i. Engage urgently with network operators to review the methodology they have used to arrive at the RIIO-T2 baselines and justification for improvement factor of 15%.

ii. Incorporate the 2019/20 IIG leakage data, which Ofgem should now have available in their calculation, with the performance factor amended accordingly.

iii. Review the Draft Determination methodology to take into account assets installed in RIIO-T1 leaking in line with their agreed design leakage rate. This equipment by design would not have been topped up in RIIO-T1 but may need replenished in RIIO-T2 and in future periods. We strongly recommend instead that the manufacturers' design leakage rate based on international standards should be used to set our baseline targets, as we have laid out above.

iv. Recognise that leakage targets need to be increased as the SF_6 and IIG inventory grow and clarify how they propose to calculate the increase - confirm if this will be based on design leakage rates and if so, will this be using company or international standards as we propose.

v. Review the Global Worming Potential (GWP) value of 23,900 for SF_6 proposed in the Draft Determination and confirm that 23,500 should be used. This will ensure a consistent value for the GWP of SF_6 is used across all RIIO-T2 reporting.

vi. Redefine the scope of the IIG incentive to include gases only with a GWP greater than 1. There are currently up to seven IIG gases, including SF_6, either available in the market or in development. Three of these will have a GWP less than or equal to 1. All gases with a GWP less than or equal to 1 should be excluded from the IIG incentive.

SPT QUESTIONS

SPTQ1. Do you agree with our proposals on the bespoke ODIs? If you disagree, please outline why.

7.130 We fundamentally disagree with Ofgem's proposals that rejected all but one (a reputational one) of our bespoke ODI proposals. The overall incentive package is still unclear, but our current forecast is that the output incentive range incorporating common and bespoke ODI is a downside of £12.3m and a maximum upside of £2.3m per annum. This is compared to a downside of £12.7m and upside of £12.9m for the RIIO-T1 period.

7.131 Ofgem has reached this unacceptable position despite the extensive evidence we submitted to Ofgem (see Appendix A: BESPOKE FINANCIAL ODI CHECKLIST of Annex 12 of our December 2019 Business Plan) to demonstrate all of our ODI proposals fulfilled the criteria set out in Ofgem's September 2019 RIIO-2 Business Plan Guidance[16]. Additionally, in Annex 12, we demonstrated the positive NPV and CVP that each of our financial ODIs would deliver. Most significantly each of our proposed ODIs are supported by, and intended to deliver on, the consumer, customer and stakeholder feedback we have received and used as the basis for our ODI proposals. This is also laid in Annex 12 and specifically in Appendix B: CONSUMER, NETWORK CUSTOMER & WIDER STAKEHOLDER FEEDBACK and Appendix C: OUR ODI COMMITMENTS. Worryingly, this is consistent with Ofgem's broad approach which appears to ignore our customer and stakeholder feedback in a variety of areas in its Draft Determination.

7.132 We note that across the ET, GT and GD submissions, Ofgem rejected 83% of the ODI proposals submitted. A figure of this magnitude leads us, and others across industry, to the conclusion that the explanations Ofgem set out to define ODIs, as well as the purpose and criteria Ofgem wanted ODIs to address, were either unclear, or that a broader policy decision has been taken by Ofgem on the value of incentive regulation for network companies. Whatever the conclusion, the approach taken by Ofgem in assessing and dismissing the vast majority of incentives proposed is a fundamental failure by the regulator. We address below the ODIs listed in Table 10 of the SPT Annex that are erroneously not covered by specific questions in the consultation.

Stakeholder engagement plus

7.133 This financial ODI builds on our detailed and extensive plans to deliver stakeholder engagement as a business as usual activity (see our main Business Plan Chapter "Continuing to Engage with our Stakeholders"). Ofgem states, in Table 10 of the SPT Annex, the reason for rejecting this proposal is that all stakeholder engagement should be considered as business as usual activity. We disagree with this policy position. The three initiatives we identified within this proposal are all developing areas of immaturity yet are important to support the low carbon transition going beyond our core business activities. We have not factored in these activities into our baseline funding for stakeholder engagement as these are emerging areas with uncertain costs and levels of activity dependent on the volume of uptake in stakeholder the communities that may come forward. We believe an output incentive is a more appropriate mechanism to encourage an appropriate level of investment, which will protect consumers from the cost uncertainty and only reward outcomes where they have been delivered. Customers have demonstrated their support for these proposals as we have documented within Section 4.5 of Annex 12 of our Business Plan.

7.134 Ofgem claims in Table 10 of the SPT Annex that we have provided insufficient justification and evidence of consumer value, despite the positive NVP and consumer value proposition we present. We are disappointed that Ofgem did not submit any supplementary questions (SQ's) to us following submission of our Business Plan as part of the formal SQ process to allow us the opportunity to supplement or clarify the evidence provided. Ofgem provide no additional explanation other than the summary table in the Draft Determination which cannot be viewed as being an acceptable level of feedback.

Optimising network availability for connected generation

7.135 In rejecting this bespoke ODI, Ofgem provided an unacceptably low level of detail to support their position, limiting this to just four sentences in Table 10 of the SPT Annex. No additional explanation was provided by Ofgem on this proposal nor were any supplementary questions related to this proposal submitted to us following our Business Plan submission in December.

7.136 Ofgem provides very limited justification to support their views that the direct benefit of this ODI proposal would fall to the generator rather than the consumer; that the generator has provisions to pay for the services that SPT are proposing; and that TOs will be sufficiently incentivised to improve their performance in minimising the impact of planned outages on their customers through the Quality of Connections survey. Ofgem also comments that this potentially risks a double reward situation. We provide a response to each of these points in turn.

The direct benefit of this proposal would fall to the generator

7.137 Our proposed incentive delivers benefits to multiple generators. The ESO will benefit from not having to buy more energy on the market to make up the shortfall, and consumers will benefit from lower constraint payments which are then socialised through BSUoS. The development and provision of renewable energy relies on developers building and operating low carbon generation and that they receive remuneration in the energy market. Delivering Net Zero requires generators to be paid and to be profitable and consumer benefits will naturally follow.

7.138 This proposal will deliver increased low carbon flows entering the electricity system than would otherwise be the case. Our proposal explains (section 4.6.6 to 4.6.8 of Annex 12 of our Business Plan) potentially provide optimisation of network availability by though various solutions including:

- Applying dynamic line ratings to constrained areas of our network will provide better availability for generators onto our network for short periods.
- Providing additional services to reduce the extent of duration of planned outages where generation is affected as well as demand.
- Identifying alternative design or construction solutions at an early stage to mitigate the effect of major construction works on connected generation.

7.139 These solutions will allow us to reduce outage times, avoid shutting down generation and avoid constraint costs that the ESO may have to make to recover the loss of duration that our essential planned outages sometimes require. All these solutions require cost and risk for our business and are not currently funded. This incentive would provide a mechanism to mitigate these costs and risks which are difficult to forecast, which is the case throughout the price control period.

7.140 Appendix E of Annex 12 of our Business Plan provides additional explanation and examples of the benefits these solutions can provide including an example that was presented by the NGESO at the Sept 2019 OC2 forum:

> "*An initial outage plan to commission a new substation required outages for 10 days on two single circuits in the same geographical area, which reduced the thermal export capability of the group to 130MW. NGESO worked in partnership with the TO to review all possible options to deliver the work whilst reducing the impact on the system. After careful assessment and optimisation, the outage combination was split into sequential single outages on separate days and was still completed within the original 10-day period. This action increased the thermal export capability limit to 260MW and released an estimated 28,600MWh of renewable generation to the market reducing GHG emissions by over 8000t with a value of £400k to consumers*."

7.141 Inevitably, generators will benefit from this from the selling of additional units of energy. Consumers will also benefit from the reduction of carbon in the environment. This is the same dynamic for the entire the Net Zero agenda and Ofgem's use of this as a reason to reject implementing this proposal highlights a fundamental flaw in their thinking.

<u>The generator has provisions to pay for the services that SPT are proposing;</u>

7.142 This is just one example of how this incentive could drive benefits for customers and consumers. Ofgem misses the point that the incentive is intended to mitigate the risk and cost of responding to this type of scenario. Not to fund the costs of the assets. The customer is rightly paying for the additional asset costs where they forecast, they will benefit by avoided loss of revenue. Consumers will benefit from the increase low carbon energy flowing.

7.143 In this scenario the generator chooses to pay for a more expensive asset-based solution to mitigate the extent of a planned outage on their network availability. The value of these costs is not intended to be covered by the incentive and avoids high cost being socialised to consumers.

7.144 We applied such a principle in RIIO-T1 which involved the replacement of a grid substation that supplied a single circuit connected wind farm. The generator was exposed to a six-month outage while the asset replacement work was being carried out. A more expensive design allowed for the generator to be temporarily connected during most of the outage. The generator paid for that and consumers and wider society benefited from the low carbon generation than would otherwise have been lost. This sort of solution will be rare in the future but is one element of the package of services that this proposal will incentivise TOs to deliver outside of their 'business as usual' approach. TOs have no obligation, nor are we funded, to deliver this type of service to generators and delivering it requires time and effort and carries risk. Should that service be delivered, the generator will pay for the service and not the consumer. The TO recovers no benefit. The incentive is solely to mitigate the TO risk and reflect the benefit consumers attain from the increased low carbon flows.

7.145 **TOs will be sufficiently incentivised to improve their performance in minimising the impact of planned outages on their customers through the Quality of Connections survey**

Conclusions

7.146 The Quality of Connections Survey is a broad incentive covering the full life cycle of the connection process and measures performance in respect of our customer satisfaction against specific milestones. In contrast, this Optimising Network Availability for Connected Generation bespoke incentive proposal targets specific behaviour and services that, if delivered, will benefit consumers by increasing the volume of low carbon generation coming onto the network. This is not a general service or interaction which we will necessarily have with all our connected generators throughout an incentive period which the Quality of Connection Survey incentive covers. This proposal provides for specific services on specific occasions that would not be captured in the Quality of Connections Survey. This incentive delivers value to consumers in terms of additional low carbon flows that will be achieved.

7.147 Stakeholder feedback supports this proposal. The extensive engagement we undertook throughout the development of our Business Plan (see Table 14 on page 29 of Annex 12) emphasised the need for an incentive to support generation customers connected to our network, in the same way the ENS incentive supports reliability beyond business as usual for demand customers.

7.148 This incentive provides that, whilst delivering additional benefits to consumers, it facilitates an increase in low carbon energy flows onto the network that otherwise would not be flowing. In many cases the system balancing that the ESO will undertake to replace the lost energy that our proposal would release, will come from gas-peaking plant which is higher cost and carries more carbon impact. This proposal as well as bringing low carbon benefits will reduce constraint costs by offering alternative solutions or avoiding the network constraint that needs to be resolved.

Delivery against our Stakeholder Strategy

7.149 Chapter 7 of Annex 12 of our Business Plan submission describes our proposals for an enduring role for our User Group throughout the RIIO-T2 period. As explained in those proposals, we intended to report progress to the User Group against the output commitments we have made for each ODI in response to our consumer, network customer and wider stakeholder feedback. To demonstrate our overall performance, we also proposed a set of Core Metrics as detailed in our Business Plan, which together constitute an overall balanced scorecard approach.

7.150 Ofgem rejects our proposals in the Draft Determination and states in Table 10 of the SPT Annex that it is unnecessary to include the proposal as a reputational ODI and instead unreasonably expect us to deliver this as part of our stakeholder strategy and associated annual reporting.

7.151 We agree that a reputational ODI is not necessarily required but believe that an ODI could provide a clear framework for this proposal and enhance accountability to our stakeholders. We would value Ofgem's views on the role of the User Group and reporting mechanisms we propose.

Non-Lead Asset Output Measurement

7.152 Section 5.4 of Annex 12 of our Business Plan explains that we have recently developed monetised risk models for some non-lead assets, and we propose to set a target for these for the RIIO-T2 period.

7.153 In direct response to stakeholder feedback, as also detailed in Section 5.4 of Annex 12 of the Business Plan, we proposed this Non-Lead Asset Output Measurement reputational ODI as a mechanism to ensure greater accountability and transparency to this activity. In Table 10 of the SPT Annex, Ofgem suggest they support the principle, so it is unclear why they would reject this proposal. We would therefore welcome more clarity on Ofgem’s views

SPTQ2. Do you agree that SPT's bespoke ODI-R would be in the interests of existing and future consumers and do you have any views on the proposed metrics to track SPT's progress in delivering the ODI-R?

7.154 We welcome Ofgem's acceptance of our ODI-R Net Zero Fund proposal. We strongly believe it is in the interests of existing and future consumers for the reasons we have provided in section 6.1.8 of Annex 12 of our Business Plan submission.

7.155 We would welcome the opportunity to work with Ofgem to develop the detail on how delivery of this output will be measured and the mechanism for funding projects whose timelines may extend beyond the RIIO-T2 period.

SPTQ3. Do you agree with our proposal to reject SPT's bespoke ODI-F at this time?

7.156 The Whole System ESO-TO Constraint Mitigation proposal is laid out in Section 5.5 of Annex 12 of our RIIO-T2 Business Plan. Its purpose is to respond to the growing cost of balancing services faced by consumers and specifically the constraint costs that can arise when essential network outages are taken.

7.157 The reasons why Ofgem rejected this proposal are summarised in Table 10 of the SPT Annex and set out in paragraph 2.16 of the SPT Annex. They explain that the example we provide of a failed STCP11-4 proposal demonstrates that the STCP process can work without an incentive. This is self-evident from our example and misses the real lesson from this example, namely that a future network outage could have been entirely avoided had it been approved on the current terms of the STCP 11-4 process. It also highlights the dependency on the ESO of being able to forecast constraint cost savings accurately for future years when limited information is available. Whilst these issues may be able to be resolved by amendments to the STCP 11-4 process it still would not resolve the lack of an incentive on the ESO and TOs to mitigate the costs and risk of promoting such solutions.

7.158 The STCP 11-4 process is insufficient as a standalone mechanism to drive proactive behaviour by the TOs or ESO to identify potential solutions and assess these in delivering consumer benefits by reducing the risk of future constraint. A supportive regulatory incentive is therefore required. Given the uncertainty on the extent and scope of potential mitigation solutions that could be required throughout the price control period, baseline funding under the corresponding TOTEX incentive is not suitable. A reputational incentive will bring some transparency to this area but will not mitigate the cost and risk of delivering solutions which accrue no value to the network companies. Instead, this targeted, robust, capped and funded mechanism is the right way forward.

7.159 In paragraph 2.17 of the ET Annex, Ofgem points to the recent introduction of STCP 11-4 as further justification for rejecting this ODI. We explained in section 5.5 of Annex 12 of our RIIO-T2 Business Plan that the STCP 11-4 was adopted into the STC in April 2018. The corresponding licence mechanism to provide funding for STCP 11-4 was included in the NGESO licence in April 2017 as Special Condition 4J "The SO-TO mechanism". To date only one proposal has been approved and this was in early 2020. The proposal was implemented by SPT to install a by-pass of the Tongland quad-booster in the Dumfries and Galloway region of our network. This cost us as TO only a few thousand pounds and to date the ESO have indicated savings of £1.5m in avoided constraint costs. These savings will continue to grow until a future network reinforcement is completed.

7.160 All of the TOs brought forward ODI or CVP proposals in this area in their RIIO-T2 Business Plan submissions. Recognising the shared purpose of our respective proposals the TOs collaborated in the early part of 2020, to develop a joint proposal which they submitted to Ofgem by email on the 15th May 2020[193]. This proposal was also supported by the ESO.

7.161 However, provided that the joint proposal brought forward by the three TOs is accepted by Ofgem, we would not object to the rejection of our bespoke ODI proposal.

[193] This is referred to by Ofgem in the SPT Annex [paragraph 2.26]

7.162 We provide our views as to why this joint proposal should be accepted in response to SPTQ5 below.

SPTQ4. Do you agree that SPT's bespoke ODI-F should be rejected?

7.163 We disagree with Ofgem's rejection of the ODI-F for an additional contribution to the low carbon transition. In Table 10 of the SPT Annex, Ofgem summarise their reasons for rejecting bespoke ODI proposal as not being good value for money for consumers. In paragraph 2.25 of the ET Annex Ofgem provides three reasons for this view which we address in turn:

<u>We proposed that our User Group would be well placed to assess our performance against this incentive. Ofgem are looking for more detail on the methodology that would be used to make this assessment.</u>

7.164 Section 6.2.4 of Annex 12 of our Business Plan provides an explanation of the principles of the methodology we envisage. This is based on straightforward project milestones that would demonstrate our progress in delivering these initiatives. We emphasise that final details would be developed with the User Group and would be subject to Ofgem approval. We recognise that more detail is required but we do not accept this is a reason for rejecting the proposal.

7.165 This approach is intended to build on the approach the RIIO-T1 Environmental Discretionary Reward (EDR) used to assess environmental initiatives and performance by a stakeholder panel. It provides a more targeted and less complex approach which were recurring criticisms of the EDR mechanism.

7.166 It also allows for the areas where there is low maturity and uncertainty on the extent and scope of the initiatives to achieve significant outcomes. Our proposals for "Maximising Supply Chain Sustainability" and "Delivering Biodiversity Net Gain" fall into this category. These are areas where costs and service levels need to be established but cannot yet be determined. Without this incentive there is no mandate for SPT to invest time and effort into these areas, and no measures to mitigate the risk and costs to do so. Our proposal de-risks the consumer cost impact as our User Group provide informed and external views to ensure that these initiatives only reward real progress with tangible benefits. If no progress or benefit is achieved no reward will be delivered to SPT.

<u>Ofgem points to the lack of a baseline in the two initiatives for "Maximising Supply Chain Sustainability" and "Delivering Biodiversity Net Gain" as insufficient to allow the User Group to assess performance.</u>

7.167 The explanation provided in the previous point explains this and emphasises that the very reason to have this incentive is because there is a need to enable a baseline position to be achieved.

7.168 In contrast the proposal for "Accelerating Adoption of our Low Carbon Fleet" does allow us to present a benchmark as the volume and costs can be forecast to a reasonable degree of confidence.

7.169 The reason for including this initiative in our proposed incentive package is that the ability to accelerate the uptake of EVs is subject to dependencies beyond our control. However, with an incentive focused on encouraging the uptake we believe that we will succeed in driving progress throughout RIIO-T2. Again, the risk to consumers is removed by our assessment approach whilst the mandate to focus on this, and the mitigation of risk and costs, are provided by our incentive proposal.

<u>Ofgem provides evidence that our proposed incentive rate is too high should we be able to achieve a 100% rollout of EV's in the RIIO-T2 period. We would be interested in understanding Ofgem's background calculation in determining this view. If verified, we agree this would be an appropriate measure to calibrate this incentive</u>

7.170 We are confident that none of the reasons Ofgem has provided present significant obstacles to resolve. We request that Ofgem works with us to achieve this and accept a revised proposal at Final Determination stage which includes these proposed incentives. This will avoid consumers losing out on a proposal that is supported by stakeholders, with a net benefit of over £10m (see Table 28 of Annex 12 of our Business Plan) and consumer value proposition of £3.16m. (Annex 30 CVP 7.5 of our Business Plan).

SPTQ5. Do you agree with our consultation position to reject the "RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs"?

7.171 Our proposal builds on and supersedes the Whole System ESO-TO Constraint Mitigation proposal addressed in SPTQ3 above. This response also builds on the arguments we have set out for SPTQ3.

7.172 As is noted in Ofgem's Table 12 of the SPT Annex, this was a joint proposal which was brought forward by the TOs as explained in our response to SPTQ3 above. The proposal is supported by the ESO and builds on the various ODI and CVP proposals that each TO submitted in their RIIO-T2 Business Plans.

7.173 There is also positive evidence of co-ordination and support in the ESO RIIO-2 framework where the ESO Annex (paragraph 3.59) includes a proposal for the ESO to regularly report evidence including:

- *£m avoided balancing costs saved through short term outage optimisation decisions (through use of STCP 11.4).*

7.174 The alignment of this measure across the ESO and TO frameworks demonstrates its significance and importance and is essential to make this whole system incentive work effectively for consumers. The schemes promoted under STCP 11-4 could save consumers millions of pounds in constraint cost reduction (NGET forecast a £188m saving in their corresponding CVP proposal). If the ESO develops this reporting metric effectively it should provide an appropriate mechanism to track the benefits of this incentive.

7.175 This proposal addresses the fundamental problem identified across the TO submissions that the cost and risk of promoting these solutions is not provided for, or effectively addressed, by the reputational incentives being proposed by Ofgem for the TOs or the ESO. This is a clear gap in the existing regulatory framework. The lack of a financial incentive to deliver these solutions, which go beyond business as usual activities, and provides no direct benefit or value to TOs or the ESO, will result in few if any schemes being brought forward.

7.176 Ofgem, in its Draft Determination (Table 12 of the SPT Annex), encourages the TOs and ESO to continue discussions on how to resolve the barriers that they we have identified in the STCP 4 process. However, this fails to address the root cause of the problem, which is the lack of a clear and specific regulatory mandate for both ESO and TOs to proactively seek solutions that deliver future constraint cost savings from asset-based infrastructure solutions for essential planned outage activities.

7.177 This incentive proposal demonstrates a strong commitment from the TOs and, in itself, is evidence that there is a real gap that needs to be resolved. It presents a clear opportunity to deliver a workable solution that will reduce consumers costs by reducing the whole system costs associated with essential planned outages.

7.178 In the existing regulatory framework, the linkage to implement asset-based network solutions to mitigate the risk of high constraint costs associated with essential planned outages exists through the STCP 11-4 process. However, we strongly believe this mechanism requires an associated regulatory incentive to make it effective. This incentive proposal is a robust, staged approach that will develop both the STCP 11-4 process and establish an optimal incentive mechanism with low risk in terms of consumer bill impact that could bring high value benefits for consumers. Given Ofgem's recent announcement to launch an investigation into the ESO's management of balancing system costs for the period March to July 2020, we believe Ofgem should be looking at every option available to reduce ever increasing constraint costs. This is therefore an opportunity that should not be missed. We challenge Ofgem's reasons for rejecting this proposal as follows: Ofgem's summary view in Table 10 is that they have insufficient information to understand why an incentive is required to encourage the use of STCP 11.4 and is out with the remit of the NIA scope.

7.179 We provided significant explanation in our original proposal as set out in section 5.5 of our Annex 12 of our Business Plan. Further, additional explanation for this proposal was provided in response to supplementary question SPTL_SQ_Pol_09. Indeed, this joint proposal submitted to Ofgem by email on the

15th May 2020, was supported by a 13-page document explaining the need for this incentive and specifically responding the clarification points Ofgem raised by email of 21st April 2020 which were:

i. Further clarity on the need for/ value of incentivising SO:TO collaboration

ii. Potential tools to measure the whole system benefits of the interventions by the TOs through these proposals.

iii. Proposals to calculate the counterfactual to the constraint costs post-adoption of a flexible solution to ensure the risk of double counting via other existing incentives is minimised.

iv. TO views on the protections that could be in place to safeguard against TO outage plans being inflated or adjusted to prioritise certain works in order to receive incentive payments.

7.180 We would therefore welcome specific feedback from Ofgem as to the information they believe is lacking so we can provide it, as we are confident that we addressed each of the points raised in the associated SQ.

7.181 By way of example, Annex 12 included positive NPV values of £97.8m. Additional explanation was given for this value in response to supplementary question SPTL_SQ_Pol_09. Annex 30 of our Business Plan also demonstrated a Customer Value Proposition (CVP 7.4) of £21m per annum provided by this proposal.

7.182 In paragraph 2.28 of the SPT Annex, Ofgem suggests that the barriers we have identified in respect of STCP 11-4, if resolved, will achieve the necessary outcomes for consumers our proposal identifies. In paragraph 2.29 of the SPT Annex Ofgem explains it does not see the need for an ODI to support the use of STCP 11.4.

7.183 These arguments fail to address the root cause of the problem, nor the extent of the benefits it will deliver. These are:

- The high-level requirements for co-ordination between the ESO and TOs in this area in the existing ESO and TO regulatory frameworks is not supported by specific, targeted incentives or mechanisms to enable the TOs or ESO to proactively seek solutions that deliver future constraint cost savings from asset-based infrastructure solutions for essential planned outage activities.

- The cost and risk of promoting these solutions is not accommodated or effectively addressed by the reputational incentives the TOs and ESO are currently being awarded by Ofgem.

- The potential schemes envisaged in the scope of STCP 11-4 could save consumers millions of pounds in constraint cost reduction; SPT have cautiously estimated a £97.8m benefit for consumers in our Business Plan and NGET forecast a £188m saving in their corresponding CVP proposal. However, the lack of an incentive to deliver these solutions which are undoubtedly beyond business as usual activities and generate no benefit to TOs or the ESO will result in few, if any, schemes being brought forward in line with the current level of activity.

7.184 In paragraph 2.29 of the SPT Annex, Ofgem refers to KPI 11 proposed by the TOs in their joint revision to the Network Access Policy. This KPI is intended to support this ODI proposal and is intended to deliver accountability and transparency on the use and effectiveness of the ODI. However, this KPI will not in itself drive the cost and risk mitigation to support the proactive behaviour that this financial incentive will enable. It will therefore not be able to achieve the Stage 3 element of our proposal as Ofgem suggest. Please see our response to ETQ3 for further explanation.

7.185 Finally, Ofgem point to their SSMD decision of May 2019 that NIA will be focused on three areas including "*projects related to the longer-term energy system transition and addressing consumer vulnerability*".

7.186 This is a difficult argument to understand as our proposal clearly supports both these elements by:

1. Delivering costs savings to consumers facing increasingly higher bills as a result of ever-increasing constraint costs; and
2. Providing a mechanism to link asset-based solutions to reduce network constraints associated with operational conditions in future years. No such mechanism currently exists and the proposed deployment of this in a staged approach will ensure a robust and enduring tool that will serve future consumers and play an important role in the future net-zero system.

7.187 For the reasons set out above, Ofgem should approve this proposal in their Final Determination.

Chapter 8: NARM

Introduction

8.1 As explained in the RIIO-2 Draft Determinations Electricity Transmission Annex ("ET Annex") at paragraph 2.51, the Network Asset Risk Metric ("NARM") has been developed to quantify the benefit to consumers of the companies' asset management activities and that, in RIIO-2, this will be used as the output to hold the companies accountable for their investment decisions. The development of NARM is the result of a significant effort invested by all parties within the NARM working groups over the past couple of years. We have provided responses to the specific questions in the Draft Determination within this Chapter but we would like to draw particular attention to some areas below.

Process, Governance & Assurance

8.2 In March 2019, Ofgem published the RIIO-2 draft data templates and associated instructions and guidance to be used by the network companies for the draft RIIO-2 business plan submissions in July and October 2019. However at this time, Ofgem did not publish the NARM associated documents, namely:

- NARM Business Plan Data Tables ("NARM BPDT")
- NARM BPDT Guidance
- MRB template file for long-term risk benefit outputs, used for the calculation of the Baseline Risk Outputs (the "Long-term Risk Benefit Template File").

8.3 Instead, the NARMS associated documents listed above were sent to the network companies by email on the 12th of April 2019.

8.4 The NARM BPDT and NARM BPDT Guidance initial proposals were subsequently updated by Ofgem after different discussions with the Companies in the Working groups and sector specific meetings, firstly there was a version circulated by email on the 13th of August to be used in the October Draft submission, thereafter the final version of these documents was published in Ofgem website on the 20th of September 2019 to be used in the Final Business Plan submission in December. However, the Long-term Risk Benefit Template File was neither published nor updated by Ofgem.

8.5 The Long-term Risk Benefit Template File was used for two different purposes, (i) to produce the network risk benefit as an input for the Cost Benefit Analysis and (ii) to produce the network risk outputs of the proposed Business Plan interventions (the Baseline Risk Outputs referred to above). It should be noted that the long-term risk benefit calculation or Risk Outputs are not defined within the current approved version of the NOMs Methodology, Version 18. There were a number of questions raised by the ETO companies about the completion of those templates after they were issued for review, those were clarified by Ofgem during different engagement opportunities, either in the NARM Working groups or specific calls. Companies were also instructed to modify those templates for the correction of one formula, relating to annual discounting, as it was identified to be erroneous. The details of the formula correction, assumption and allocation methodology used in completing those have been documented in the commentary file, namely 'RIIO-T2 NARM LTRB Commentary', submitted in both draft business plan and the final Business Plan submission.

8.6 The late development of the Risk Output calculation, together with the lack of a finalised template and clear guidance for the completion of those serving the two different purposes mentioned in the previous paragraph, has led to inconsistencies in the calculations and assumptions made by the different TOs. While this has not directly impacted our proposals, it will make comparisons between companies difficult to achieve. We would welcome clarity from Ofgem on a consistent approach to the calculation within sectors.

NARM Output Model Inconsistencies

8.7 As described in the RIIO-2 Draft Determinations NARM Annex (the "NARM Annex"), Ofgem has derived the Baseline Network Risk Outputs for each company using the companies' submitted views of the long-term risk benefit to be delivered through their proposed investments, along with their separate assessment of allowed intervention volumes.

8.8 The first step of this process has been the reconciliation by Ofgem of the volumes provided by the companies as part of the BPDT submissions (table C2.5) with the NARM intervention volumes provided by the companies as part of the NARM BPDTs (Table N1.3.). Ofgem's assumption (as described in Appendix 3 of the NARM Annex) that those volumes should align is inconsistent with their own published guidance for BPDT and NARM BPDT. As an example, in accordance with the BPDT guidance (selection of scheme type in section C0.7: Non Load Master Data Table starting), all refurbishment interventions contained within a scheme whose primary driver is Replacement would have been recorded as activities in the Cost and Volumes tables (C2.5), there would not have a 'removal volume' recorded. As per the prime driver such schemes would be reported as Replacement. However, a per Ofgem analysis for determining the Baseline Network Risk Output (BNRO), these asset refurbishments would have not been considered as Ofgem identify volumes for replacement schemes as being the volumes off (removals). Within the NARM BPDT such interventions will have a volume before and after for the replacement and refurbishment components. The assignment of asset intervention volumes has been documented in detail in the Commentary files submitted alongside the BPDT and the NARMS BPDT for each draft and final Business Plan Submission following the latest Guidance on Business Plan Data Templates for RIIO-T2 Electricity Transmission Price Control. The feedback and information provided by SPT on this issue were not used effectively by Ofgem to inform the final Business Plan submission templates and instructions. If Ofgem's expectation was to align the volumes in NARMs and Costs and Volumes ("CV") tables, we would have welcomed greater engagement from Ofgem to discuss the assumptions and other issues identified between the first draft business plan submission and the final business plan submission.

8.9 In our view, such greater engagement would have avoided the use by Ofgem of a volume scaler in the derivation of the BNRO, where its use introduces errors and inaccuracies in the definition of those. We also note that these issues were again explained by us in response to SPTL_SQ_NARM_1. We do however welcome the opportunity provided by Ofgem to work with the companies post-Draft Determination to better align the data avoiding the need of a volume scaler for Final Determinations.

NARM Funding Adjustment and Penalty Mechanism issues

8.10 SPT welcomes the NARM Supporting Workbook provided together with NARM Annex in the Draft Determination to help stakeholders and companies understand how the NARM Funding Adjustment and Penalty Mechanism, which is to be a feature of the companies' licences, is intended to work. However, we do not believe that mechanism has been properly tested and validated to ensure it produces reliable and fair outcomes for consumers. This raises questions about the level of assurance and governance processes put in place by Ofgem prior to publication of the Draft Determination.

8.11 We fully agree with Ofgem's statements in paragraph 4.5 of the NARM Annex that companies should not enjoy windfall gains from simply re-planning their work to intervene on cheaper assets or alternative interventions. Nevertheless, this mechanism will not incentivise appropriate company behaviour or achieve efficient delivery. We have demonstrated this through a number of examples shared at the last NARM- ET specific Working Group. It is evident from these examples that risks and gains are not fairly allocated between the network companies and the consumers. Further detail is provided in our response to NARMQ3.

8.12 We have raised concern on numerous occasions that the Unit cost of risk delivered or £/£R approach is unlikely to produce robust outcomes for ET. This was first raised in the NOMs Cross Sector working groups back in 2017 and had been discussed in different other engagement opportunities, namely ET and CS NARM WGs since. SPT provided an assessment of the cost to risk benefit relationship of a number of asset classes within Annex 19 of our Business Plan Submission highlighting the risks associated with carrying out assessment of interventions on this basis alone.

8.13 Instead, the approach should be the assessment on a scheme-by-scheme basis. This was proposed and agreed by all parties in the NOMs Cross Sector Working Group during the discussion around the NOMS incentive for RIIO-T1, which leaves the development of an adequate methodology pending the completion of the Rebasing exercise. However, this has not yet taken place and this critical element remains outstanding.

8.14 While this approach was deemed suitable for other sectors, by proposing to develop an alternative, Ofgem agreed with the companies that it was not appropriate for electricity transmission. It is therefore surprising that the NARMs mechanism proposal seems to ignore the previous work and decisions and has proposed a similar approach to the one rejected for RIIO-T1.

Responses to Consultation Questions – NARM

NARMQ1. Do you agree with our proposals on the scope of work within each of the NARM Funding Categories and on the associated funding arrangements?

8.15 We broadly agree with the proposals outlined in the NARM Annex in relation to the scope of work within each of the NARM Funding Categories and associated funding arrangements.

8.16 That said, we would like to draw attention to the definition of 'NARM Target' or 'Baseline Network Risk Outputs'. The NARM Annex states that when Ofgem refers to refers 'NARM Target' or 'Baseline Network Risk Outputs' it means the Monetised Risk Benefit expected to be delivered by interventions in the A1 funding category. However, this does not make any distinction between interventions on the prime assets and/or consequential assets.

8.17 We believe A1 consequential interventions, interventions on Consequential Assets,[194] should be excluded from the NARMs Target since they are required to facilitate the intervention on the prime asset but may not be justified on its own merits. That could lead to companies being assigned Baseline Network Risk Outputs for work that has not been justified on its own merits, in the event there is no need to intervene on the prime asset (main driver).

NARMQ2. Do you agree the funding adjustment principles and our proposals for applying funding adjustments?

8.18 We agree that funding arrangements should aim to balance consumer protection and incentives for companies to make efficiency savings by improving their asset management activities. In that respect, we welcome a number of the proposals presented, such as the principle to keep companies neutral for non-intervention risk changes and allowing companies to share with consumers the cost savings achieved through genuine cost efficiencies.

8.19 However, there are three main considerations we would like to bring to Ofgem's attention.

8.20 Firstly, there are three non-intervention risk changes specified: (i) NARM methodology changes, (ii) consequence of failure changes and (iii) Data cleansing. The reference to the fixed parameters for the consequences of failures requires further clarification. If those parameters refer to the financial values assigned to the consequences of failure as per the current approved methodology, SPT agrees with that approach. Those values are currently expressed in 2018 prices that could be updated as appropriate. For other consequences of failure changes that are not part of a methodology change (we assumed those would exclude the changes in the financial parameters referred above), Ofgem propose that companies would only be held neutral it they can demonstrate that have taken reasonable actions to mitigate those. SPT does not agree with that since the type of work required to mitigate those would not be included within the A1 funding category for non-load works. The degree of interconnectivity of the transmission network implies that any change in its configuration would have an impact on the surrounding assets. That impact becomes evident in the system consequences assigned to every lead asset under the NOMs methodology. Those parameters are dynamic in nature and would change as a result of any configuration change such as addition or disposals of assets as well as rearrangement of the existing ones, usually as a result of load driven interventions. As an example, the consequence of failure of a transformer planned for an A1 replacement intervention would be reduced in the case of load related addition of an extra transformer unit supplying the same demand group before the end of the RIIO-T2 period, in this case the company would have no ability to mitigate those consequences of failure changes. Through the discussion in the NARM Working Groups there has always been a recognition of the challenges associated with the dynamic nature of the network in relation to the NARM reporting and therefore it was agreed to use the system consequences values as per the configuration of the network at the time of the preparation of the Business Plan submission. Companies

[194] Consequential assets as defined in "RIIO-T2 regulatory instructions and guidance: Glossary" v1.3 https://www.ofgem.gov.uk/publications-and-updates/riio-2-final-data-templates-and-associated-instructions-and-guidance

should not be penalised or rewarded for the consequences of failure changes that could not be accounted for at the time of setting the outputs.

8.21 Secondly, on the treatment of non-intervention risk changes, the NARM Supporting Workbook in tab 3_Non_Intervention_Adjustment indicates "*Adjustments will be not be applied for differences between forecast risk of asset and actual risk of asset. Such changes are for the companies to manage, whether the outcome is a gain or loss. These differences will also be addressed through the unit cost of risk delivery adjustment mechanism*" . As we have raised before in the NARM Working Groups, there are changes to be expected between the forecast risk value of assets and actual risk value of those at the end of the RIIO-T2 period. Those differences are only a consequence of the nature of SPT's Network Outputs Measures "NOMs methodology" and may not be insignificant. Companies' performance should not be impacted by a well-known mechanistic issue, whether the outcome is a gain or loss, whenever it can be demonstrated that the asset risk has evolved as expected at the business plan submission. The current methodology calculates the future deterioration of an asset (and therefore the risk value) on a continuous scale up to a value that is much higher than the maximum actual risk that an asset can achieve at any point in time. The actual risk value assigned to the asset at the end of the RIIO-T2 period in known to be lower than the forecasted value with the expected deterioration. This effect should not be taken into consideration in the performance assessment and therefore addressed through the unit cost of risk delivery adjustment mechanism. We would welcome the opportunity to work with Ofgem in the definition of a suitable reporting framework that takes into consideration the complexities of the different NOMS methodologies of each company ahead of the RIIO-T2 Business Plan Final Determination.

8.22 Thirdly, it is also proposed in paragraph 4.12 of the NARM Annex that indirect interventions to reduce the consequences of failure will be treated in the same way as work substitutions. However, the definition of indirect intervention set out in footnote 6 as "*an intervention … that modifies the probability of failure, or consequence of failure of another network asset*" is not clear and the examples provided seem to refer to three different situations in the context of NARM interventions, (i) an intervention that modifies the probability of failure of another network asset, (ii) an intervention that modifies the consequences of failure of another network asset and (iii) the addition or disposal that increases or decreases the resilience of a local or regional network. The examples provided are not relevant for the ET sector however any intervention that would fall under the A1 funding category should be justify on the same basis as any other work substitution. The addition or disposal of an asset that increases or decreases the resilience of a local or regional network should be covered under A2 funding category if that is the prime driver with no impact on the Network Risk Outputs or NARM Target and therefore it should not be treated as a work substitution for the purpose of the application of the NARM funding Adjustment and Penalty Mechanism.

NARMQ3. Do you agree with our proposed approaches to calculating funding adjustments and to application of penalties?

8.23 The proposed funding adjustment mechanism is an unnecessary step in the adjustment of funding and could lead to manifestly unfair outcomes.

8.24 We agree with Ofgem that companies may be able to re-plan their work and make alternative interventions to achieve cost reductions for the same total Network Risk Output delivery. However, after using the NARM Supporting Workbook provided with the NARM Annex to test different scenarios, we can confirm this could lead to undesired outcomes. By way of example:

- We have tested the scenario of the delivery of the Business Plan as it was submitted with the only variation being the under-delivery of one particular overhead line route project. Although this project represents less than 1% of our proposed non-load expenditure, the justified under-delivery of this scheme would represent a clawback allowance of ten times the initial allowance for that scheme.
- We have also tested the scenario of justified under-delivery of three of our proposed switchgear projects representing a material proportion of our non-load expenditure - around 15%. In this case, SPT would be rewarded with a higher allowed allowance than required with a clear loss to consumers. As such, if SPT was not able to justify the change to its plan, not only would SPT not be delivering an important element of the Business Plan to maintain a safe and resilient network, SPT would also be 'rewarded' with a higher allowance than required, even after discounting the associated penalty to the clawback allowance. This situation is equally unacceptable and clearly operates against consumers' interests.

- We have also tested some over-delivery situations, again with unsatisfactory outcomes. These examples have been shared with Ofgem and other TOs in the latest NARM TO WG the 4th of August 2020 to facilitate the assessment of the mechanism as part of ongoing engagement after the publication of the Draft Determination.

8.25 The mechanism must make adjustments that reflect the efficiently avoided or incurred costs. However, the proposal set out in the Draft Determination does not fulfil this requirement. We would be happy to continue our engagement in this area between now and the Final Determination in order to achieve a fair mechanism for companies and consumers.

8.26 The NARMs mechanism proposal is also based on the simplistic view of a unit cost per risk delivered. While this approach may be suitable for other sectors, it is not suitable for Electricity Transmission.

8.27 As explained in greater detail in Appendix 19 of our Business Plan, the proposed mechanism to adjust the Unit Cost of Risk Benefit delivered raises different issues since there is not a linear relationship between the cost and the risk benefit delivered by the different interventions. While the risk benefit delivered relates to the interventions on the seven lead assets included in the NOMs methodology, the cost associated with those interventions also include the expenditure in the non-lead assets, civil assets and indirect activities.

8.28 The proportion of the cost related to direct intervention on the lead assets over the total cost of the scheme is variable and is (in the SPT Business Plan) in a range between 17% and 80%.

8.29 The other factor that highlights issues with this approach is the significant differences in risk value between asset categories. As an example, SPT's network overhead line risk interventions account for 90% of the proposed Baseline Network Risk Outputs while only accounting for the 40% of the proposed non-load expenditure.

8.30 Both of these factors would prevent the application of the Unit Cost of Risk Delivered adjustment to the total relevant Network Risk Outputs as an optimum mechanism to derive the adjusted NARM allowance as an input of the TIM. Instead, the approach should be the assessment on a scheme by scheme basis to ensure customer protection while providing companies with a fair outcome.

8.31 The proposal to apply the Unit Cost of Risk Delivered adjustment to the whole volume of delivery, not just the part above or below the baseline target, is made on the basis that would be impractical to separate out windfall gain from genuine efficiency effort.

8.32 SPT believes companies should work together with Ofgem in defining a suitable framework to achieve that - rather than using a simplistic approach that will lead to unfair outcomes. Companies should be able to demonstrate their genuine efficiency savings using similar evidence to that provided in the Business Plan submission, allowing Ofgem to evaluate the efficiency of the cost provided in the same way without additional administrative burdens on the companies or Ofgem.

NARMQ4. Do you agree with our proposals in regards to requirements for justification cases?

8.33 We broadly agree with the requirement for justification cases and welcome the opportunity to work with Ofgem in the development of guidance in relation to the nature and quality of the evidence required. The RIIO-T2 Business Plan Investment Decision Pack defined for the Business Plan Submission has, in our opinion, an appropriate format and level of rigour for this purpose; in being the vehicle for the justification of investments in the Business Plan, it is suitable for changes to the Business Plan. We would expect that further guidance to be provided on these requirements as part of the Final Determination.

Chapter 9: Competition

Introduction

9.1 The 'early' CATO model is the only model proposed by Ofgem which could potentially deliver consumer benefit through actual competition. The 'late' Competitively Appointed Transmission Owners (CATO), Competition Proxy Model (CPM), and the Special Purpose Vehicle (SPV) models are materially flawed. Late CATO requires primary legislation. CPM does not introduce competition at all. The SPV model is unlawful.

9.2 As a general proposition, we do not agree with Ofgem's proposed position on late competition. We have not seen cogent evidence to suggest late competition models will deliver additional consumer benefits, compared to the status quo position. The assessment of projects for delivery, through models which are not yet fully developed, introduces a significant level of uncertainty and risk. Moreover, setting up and implementing a late competition model for a discrete project will incur significant implementation costs. The imposition by Ofgem of unnecessary risks and implementation costs will ultimately have an adverse effect on consumers, whether through higher bills or less reliable services (or potentially both) across the sector. Finally, and for the reasons set out in more detail below, the proposed SPV model is incapable of being delivered lawfully and should therefore not be implemented.

9.3 Notwithstanding our position that late competition is unlikely to deliver additional consumer benefit, even if Ofgem were to proceed with its policy proposals, we would urge Ofgem to ensure that any proposed competition models are fully developed and legally robust, taking account of the statutory and regulatory framework and the overall interest of consumers, before assessing any projects for delivery under these models. It is not appropriate for Ofgem to assess the viability of applying these models for the delivery of projects where there remains such inherent uncertainty around their design and impact.

9.4 Given the significant, hard-won efficiencies achieved through the RIIO-T1 period, and the further efficiency commitments proposed within the RIIO-T2 proposals, it is difficult to envisage a net benefit being achieved for consumers through delivery via a late competition model. Net benefit can only likely be achieved where: (i) the process can reveal significant further efficiency gains in terms of operational or capital expenditure; (ii) the process can somehow further reduce financing costs; and (iii) the models can be deployed with very low implementation costs. We have yet to see cogent evidence that all of these outcomes are achievable. We note that to date, the benefits case for implementing significant projects through the CPM, (which does not involve any competition), has not been sufficient to merit funding of these projects through the CPM. In relation to the Hinkley-Seabank project[195] and the Shetland Transmission project,[196] Ofgem concluded that delivery under the CPM would not be in the interests of consumers.

9.5 In developing early competition models, it must be recognised that Ofgem is the appropriate party to develop and undertake consultation on the ESO's submitted Early Competition Plan, given its potential impact on the TOs' licence obligations. Ofgem is also the body that holds the statutory duty to promote effective competition wherever appropriate, and to do so in the best interests of existing and future consumers.

9.6 The opening up of the RIIO-T2 process control to include new early and late competition models does not provide investor certainty and confidence in GB's electricity networks as stable, predictable investment opportunities. Ofgem should use the duration of the RIIO-T2 price control to further develop the early competition policy and models and to work with the UK Government to introduce the necessary CATO legislation.

[195] Ofgem, *"Hinkley - Seabank: Updated decision on delivery model"*, 22 May 2020. Ofgem state "*Having considered the information and analysis currently available to us, and all other relevant considerations, we do not consider that there is sufficient evidence that applying the CPM to HSB (and therefore departing from the existing SWW arrangements under RIIO) would be in the interests of existing and future consumers. We have therefore decided in this case not to apply the CPM to the HSB transmission project.*" (para 3.43)

[196] Ofgem, *"Shetland transmission project: Decision on Final Needs Case and Delivery Model"*, 30 July 2020. Ofgem state "*We confirm that, following consideration of consultation responses, and further analysis, 3 we have concluded that there is clear evidence that applying the CPM to the Shetland transmission project (and therefore departing from the existing Strategic Wider Works (SWW) arrangements under RIIO4) would not be in the interests of consumers. We therefore confirm that the Shetland transmission project will be funded under the SWW mechanism within RIIO-1.*" (page 6)

Responses to Consultation Questions - Competition

CORE SECTOR QUESTIONS

Q32. Do you agree with our proposed position on late competition?

9.7 Whilst SPT is strongly supportive of the promotion of competitive practices in transmission networks, we are opposed to Ofgem's proposed position on late competition for RIIO-T2. The proposals offer no certainty for TOs and it is doubtful whether they can be achieved during the RIIO-T2 period. We are yet to see any convincing evidence that these proposed late competition delivery models will deliver additional benefits to consumers. These proposals would simply introduce significant investor uncertainty to TOs, who will be unclear which, if any, late competition models will be used to deliver their proposed projects.

9.8 The Draft Determination (at Section 9 of the Core Document) proposes the introduction of late competition models of the CPM, SPV and the CATO into the RIIO-T2 framework.

9.9 We understand from discussions at the RIIO-T2 Licence Drafting Working Group on 23 July 2020, however, that Ofgem only intends to introduce licence conditions for the CPM in the RIIO-T2 licence, for its commencement on 1st April 2021. Ofgem's intention to include the licence conditions for the SPV and CATO models during the RIIO-T2 price control period is a significant concern. It would effectively open up the price control at a later date. This is an unacceptable position for a regulator to take and will undermine investor trust and confidence in the GB regulatory framework, which has already been significantly diminished by the poor levels of return currently proposed in the GB networks market.

9.10 We also have significant concerns with the introduction of a licence condition for CPM, as explained below.

Delivering Additional Consumer Benefits

9.11 Ofgem's late competition models will not deliver the scale of additional consumer benefits that Ofgem propose. Instead, given their complexity, these new delivery models are likely to cause unnecessary delay and additional costs to consumers, when compared to the current RIIO-T1 Strategic Wider Works (SWW) process and the soon-to-be Large Onshore Transmission Investment (LOTI) process. The updated Late Competition Impact Assessment document, which accompanied publication of the Sector Specific Methodology decision in May 2019, is also disappointingly lacking in detail as to how each late competition model will deliver actual additional benefits to consumers.

9.12 Similarly, the general Impact Assessment accompanying the Draft Determination published on 31 July 2020, provides no firm conclusion that the introduction of competition will bring benefit. In chapter 2 the impact is described as "*Not quantified – uncertain, but likely to result in consumer benefit and in a reduction to network companies revenues if projects are approved*." This is an unconvincing justification.

9.13 Ofgem's Late Competition Impact Assessment is now outdated for a number of reasons.

9.14 Firstly, Ofgem's latest policy position is that the SPV and CATO models are to be introduced into the RIIO-T2 price control framework at a later date. The Impact Assessment does not measure the consumer impact of the additional investment risk created by the uncertainty as to whether projects might be subject to delivery via a late competition model.

9.15 Secondly, the Impact Assessment for competition fails to address other material changes. In particular, the assessment does not include consideration of Ofgem's decision not to apply the CPM model for the Hinkley-Seabank or Shetland Transmission projects due to general lack of confidence around whether it would be in the interest of consumers.

9.16 Finally, since publication of the Impact Assessment, the RIIO-T2 framework has undergone further changes and financial markets have been significantly impacted by COVID-19. The Impact Assessment does not reflect these developments.

9.17 Robust project-specific Impact and Cost Benefit Assessments need to be undertaken before determining the most appropriate delivery model to fund a project. Such assessments must be undertaken to ensure that all options, including the LOTI, can be appropriately assessed before Ofgem decides which model to use. Consumer interests rely on this. Particularly as we continue to have concerns that the introduction of these 'novel' late competition delivery models, which have yet to be implemented, could lead to delays in project delivery of important strategic transmission infrastructure.

9.18 Our views on each of Ofgem's proposed models are set out below:[197]

Competition Proxy Model (CPM)

9.19 It is difficult to understand why Ofgem continues to consider the CPM as an appropriate delivery model for large, strategic infrastructure projects in RIIO-T2. Ofgem recently determined that it no longer had sufficient evidence that delivering either NGET's Hinkley-Seabank project or SHET-L's Shetland Islands project under the CPM would be in the best interests of existing and future GB consumers.

9.20 This raises significant doubt as to whether the CPM will ever be fit for purpose or in the best interests of consumers, particularly as the CPM was designed in the context of the RIIO-T1 framework. In the light of Ofgem's recent decisions on both of these projects, it is clear that now is the appropriate time to stop the development of the CPM altogether and to exclude it from the RIIO-T2 framework.

9.21 SPT actively participated in a series of licence drafting working groups on the CPM in 2018 and 2019, in the context of RIIO-T1. Throughout these workshops, we consistently communicated our specific concerns to Ofgem about the significant legal and practical barriers to the implementation of the CPM. In particular, the CPM's premise is fundamentally flawed because it introduces no direct competition or competitive tendering. Ofgem's analysis also does not reflect the way the project would be treated under a project finance competitive model and there are serious flaws in the cost of capital methodology adopted by Ofgem.

9.22 SPT has concerns around the concept of the 'lock in' of cheap debt, the inappropriate use of OFTO comparators, and incorrect assumptions around leverage and the cost of equity, as identified by our economic consultants, NERA, in their report provided to Ofgem. This report identified material flaws in Ofgem's capital methodology.[198]

9.23 There is also considerable concern regarding the practical elements of financing a project through the CPM. In particular, it is unclear whether the CPM could in fact be financed through a 'project finance' approach, or whether investors would even accept the CPM as a delivery mechanism on a project finance basis at the cost of capital produced by the model. These concerns are compounded by the inherent uncertainties in the framework and differences to standard project finance approaches.

9.24 The absence of a standalone CPM policy continues to be a material cause for concern, exacerbated further by the fact that the Hinkley Seabank project, which was the main conduit for the development of the CPM mechanism, is now being delivered by a different mechanism. Ofgem has not issued any CPM policy or guidance document to explain the scope or process of the policy. Nor have Ofgem explained why they have adopted a 'light touch' approach to the CPM draft licence condition for RIIO-T2, contrary to the approach taken in the RIIO-T1 licence drafting working groups. We note that Appendix 2 to the Draft Determination Core Document "clarifies" how Ofgem propose the CPM arrangements will be applied during the RIIO-2 period. Given the lack of associated consultation questions on this section, we assume Ofgem is not

[197] We have set out our position in full to Ofgem about these matters in responding to Ofgem's previous detailed consultations on the various competition proposals, including SPT's response to Ofgem's 2018 consultation on Hinkley-Seabank (March 2018); SPT's response to Ofgem's consultation on the Special Purpose Vehicle model (November 2018); and SPT's response to Ofgem's updated minded-to position for Hinkley-Seabank delivery model (November 2019). Accordingly we set out our position more briefly here.

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

proposing any alterations in the CPM policy as it has been developed so far within this Appendix 2. We will however review the updated details in Appendix 2, alongside the CPM guidance document, which we understand will be published with the Informal Licence Drafting consultation in October 2020. Only once we have had sight of the draft CPM Guidance, will we be in a position to offer feedback to Ofgem on the latest CPM policy proposals.

9.25 The scope of the CPM mechanism is still unclear. For electricity transmission, the overarching criteria for late competition of 'new, separable and high value (i.e. >£100m delivery cost)' is settled, having been the subject of extensive consultation and used as the basis for policy Impact Assessments. These terms must be stated in the licence definition of "Qualifying Assets" of the CPM licence condition so that CPM policy is limited to projects that meet this criteria. We fail to understand why Ofgem refuses to include this criteria in the definition of the RIIO-T2 CPM licence condition, despite the LOTI condition (on which the current CPM condition was modelled) specifically defining the eligibility criteria for those projects.

9.26 Ofgem must clarify our existing questions on how the CPM mechanism interacts with the LOTI and the criteria by which Ofgem will decide whether a LOTI project should instead be funded under the CPM mechanism. It is important that we, investors, generators and other stakeholders, are able to reach an informed view of the CPM policy in its entirety and assess, with certainty, how this could operate in practice in RIIO-T2.

<u>Special Purpose Vehicle (SPV) model</u>

9.27 Ofgem's proposed Special Purpose Vehicle (SPV) model will not deliver effective competition that benefits consumers today or in the future. In our view, the SPV model is not lawful, practical or cost effective. We have outlined our position in detail in our previous response to Ofgem's 2018 SPV Consultation[199] and our position on this remains unchanged.

9.28 The SPV model is unlawful because it would compel a TO to delegate its licence obligations to an SPV, against its will and without Ofgem being able to secure compliance with TO licence obligations against that SPV. If the SPV were to then cause a breach of the TO's licence, the TO could not realistically be sanctioned for that breach. As the SPV would not hold a transmission licence, Ofgem would not be able to secure compliance with the TO licence, therefore abdicating its regulatory responsibilities under the Electricity Act 1989.

9.29 It is a core principle of administrative law that a public body cannot abdicate or fetter its statutory duties or powers. It is important that the proposed SPV holds a transmission licence, including the licence requirements to comply with relevant STC duties. The lack of SPV responsibilities in these important areas will increase operational risk across the transmission network as TOs will be expected to take responsibility for, and manage the performance of, the SPVs, despite not having day-to-day control over them.

9.30 SPT's experience of using sub-contractors, developed over many years of establishing and managing large scale projects, shows that projects do not always proceed as planned. SPVs will inevitably request revenue adjustments for changes to projects. Responding to and managing these requests (whether reasonable or not) will impose further costs on TOs. As with many PFIs, circumstances may also change such that the initial deal does not remain in customers' best interests. This is reflective of the UK Government's 2018 Budget announcement to abolish future PFI and PF2 contracts, given the compelling evidence that these contracts neither deliver value for taxpayers nor genuinely transfer risk to the private sector.

9.31 Moreover, the SPV model is significantly more complex and expensive to deliver than Ofgem anticipates. A material point is that there is a likely to be a fundamental mismatch between the incentives and objectives of a TO (which is seeking procurement of a robust, enduring and efficient asset to a well understood and acceptable standard) and the incentives and objectives of an SPV (which will be to deliver an asset at the lowest short term cost with cash flow and margins maintained as a premium). This mis-match

[199] Ofgem, "Extending competition in electricity transmission: commercial and regulatory framework for the SPV Model", 14 September 2018. Available here.

of short-term versus long-term incentives will be exacerbated by the shock to the UK economy caused by the COVID-19 pandemic (due to the likely increased focus on short term cash flows by asset-light investors) and the likely slow – and potentially faltering – recovery back to historically 'normal' levels of GDP.

Competitively Appointed Transmission Owner (CATO)

9.32 It is fundamental that Ofgem acts within the statutory framework in 'extending competition in electricity transmission'. Ofgem should not press ahead with proposals until Parliament has the relevant legislation in place.

9.33 We are actively involved in the ESO's development of its Early Competition Plan as the ESO looks to further develop the design of an 'early' CATO model. As stated in our Competition Plan (Annex 18 of our Business Plan), this 'early' CATO model is the only competition model proposed by Ofgem that could deliver real competition. We set out our more detailed views on potential early competition models in our response to Q33 below.

9.34 The 'late' CATO model (whereby the TO would be responsible for design, planning and consenting of the project) adds little or no value to consumers. It will contribute to delays in the delivery of major infrastructure, as a result of planning, tendering and other process issues, resulting in material costs to consumers. It is vital that any CATO model also recognises the limitations on timing and transfer of consents regulated by Scottish land and planning rules. These rules are described in detail in our response to Ofgem's Sector Specific Methodology Consultation, dated March 2019.

Q33. Do you agree with our proposed approach on early competition?

9.35 We agree with Ofgem's position in the Draft Determination that it is not appropriate for Ofgem to finalise proposals for early competition, at this stage, as the task it set the ESO in developing its Early Competition Plan ("ECP") will not be completed until February 2021. However, we do not agree with Ofgem's proposed next steps for the development of early competition in RIIO-T2. That is because early competition delivery models are not going to be in place in time for the commencement of RIIO-T2 on 1st April 2021. The introduction of any early competition models in RIIO-T2 involves opening up the RIIO-T2 price control at a later date, which will undoubtedly damage regulatory certainty and investor trust and confidence in GB's network infrastructure. Moreover, setting up and implementing an early competition model for a discrete project will incur significant implementation costs. The imposition by Ofgem of unnecessary risks and implementation costs will ultimately have an adverse effect on consumers, whether through higher bills or less reliable services (or potentially both) across the sector.

9.36 Ofgem must act within the statutory framework when introducing early competition provisions. In particular, Ofgem should wait until Parliament has the relevant CATO legislation in place before pressing ahead with any proposals in this area.

9.37 SPT has been actively involved in the development of the ESO's ECP to date. At this stage of the ESO's development (the Early Competition Plan Phase 2 consultation), we are deeply concerned about the scale of the ESO's latest proposals, particularly given the significant impact these proposals will have on licensed network operators' abilities to develop and maintain an economic, efficient and coordinated network across GB.

9.38 We set these out in detail in our response to the ECP Phase 2 consultation and we summarise some of these key concerns below:

The ESO's role in the development of early competition policy must be consistent with the existing regulatory regime

9.39 We recognise that Ofgem requested the ESO to develop the ECP. This is set out in various documents, for example, in the RIIO-2 Sector Specific Methodology Decision relating to the ESO, the letter dated 24 September 2019 from Ofgem to the ESO (**Ofgem's Letter**) and the ESO Roles and Principles Guidance. However, as acknowledged in the Draft Determination, Ofgem must also undertake its own formal and substantive consultation on early competition. In doing so, Ofgem must comply with its statutory obligations and its own consultation policy.

9.40 In its Phase 2 Consultation, the ESO proposes fundamental modifications to a number of existing TO roles, together with an expansion to the scope of its own role. Such proposals amount to a significant change to the existing regulatory regime, which should be taken forward by Ofgem and not the ESO. As explained below, the ESO does not have either the licensing powers or regulatory responsibility to develop and implement early competition models.

9.41 Ofgem's guidance on the ESO Roles and Principles seeks to map the ESO's early competition role against ESO Standard Licence Condition C16(1)(e) and the ESO's responsibility to "*[publish] information which the licensee holds to enable electricity market participants to make efficient operational and investment decisions".* The ESO's proposals, as described within the consultation, go far beyond publishing information to enable market participants (which include the TOs) to make efficient operational and investment decisions. The ESO's proposals also go beyond its licence obligation to "*co-ordinate and direct the flow of electricity".*

9.42 Any consultation by the ESO on the proposed scope of the roles and responsibilities of parties involved in early competition models, which we expect to be covered in Phase 3 of the ESO's ECP, must be consistent with the ESO's licence and the existing regulatory regime. Unless and until that regulatory regime is modified, Ofgem is the appropriate party to develop and undertake consultation on the ECP, given its potential impact on the TOs' licence obligations. Ofgem is also the body that holds the statutory duty to promote effective competition wherever appropriate, and to do so in the best interests of existing and future consumers.

ESO proposals negatively impact on TOs' licence obligations to develop and maintain an efficient, co-ordinated and economical system

9.43 The ESO's proposals not only impact upon the TOs' licence obligations, but also significantly risk undermining the TOs' general duties under Section 9 of the Electricity Act 1989. Section 9 provides that it is the duty of each licence holder to "*develop and maintain an efficient, co-ordinated and economical system"* of electricity transmission. As we understand them, the ESO's proposals could potentially involve the shifting of certain network planning responsibilities from TOs to the ESO. This would risk significantly impacting TOs' ability to comply with their licence obligations to properly co-ordinate the system and ensure it operates efficiently and economically.

9.44 Furthermore, careful consideration is needed of the real potential impact of the TOs' and ESO's obligations under the System Operator Transmission Owner Code (STC). For example, the TOs have the responsibility to "*plan, develop, operate and maintain its Transmission System"*. The ESO's proposals risk adversely impacting the TOs' ability to, amongst other things, plan and develop their own transmission system. This in turn risks becoming a compliance issue given the TOs' and the ESO's obligation to comply with the STC at Standard Licence Condition B12.

The removal of any value threshold for projects to be delivered via early competition models is misguided

9.45 We are surprised at the ESO's consultation proposal to have no value threshold on projects potentially subject to delivery via an early competition model. This is a significant departure from existing processes and assessments and it is unclear how the ESO can be confident that consumer benefits can be derived from the delivery of projects, via early competition models, regardless of the value of the project in question. The ESO has not undertaken an Impact Assessment to understand the impact of the removal of project value threshold on GB consumers' best interests.

9.46 The Draft Determination states that, as part of its consultation on the ESO's Early Competition Plan proposals, Ofgem will set out its views *"on any appropriate criteria for identifying projects for delivery through early competition, including whether or not £50m is an appropriate cost threshold for early competition"*[200]. It is therefore inappropriate for the ESO to propose the removal of any value threshold, when Ofgem intends to hold further consultations, and presumably undertake an Impact Assessment, on whether a threshold of £50m should continue to apply for early competition.

9.47 Instead, the inclusion of a clear value threshold as part of the early competition criteria is key. The uncertainty as to which of a network operator's pipeline of future network projects will potentially be subject to delivery under an early competition model will undoubtedly affect investors' views of GB network operators as being stable, predictable regulated entities. This will in turn reduce investor appetite to invest in GB network infrastructure, at a time when significant investment is needed to facilitate the UK, Scottish and Welsh Governments' Net Zero ambitions.

<u>Proposal to have TOs participating as market players weakens existing licence obligations</u>

9.48 With the potential for early competition winners to be subject to different licence provisions (if they have a licence at all) compared to those of the incumbent TOs for network operations, the ESO's proposals have the potential to dilute the strength of the existing licence obligations that effectively safeguard the operation and maintenance of a resilient GB-wide network. This regulatory framework has been carefully designed over an extensive period of time to ensure energy security, affordability and carbon and greenhouse gas emission reductions.

9.49 In order to guarantee additional consumer benefit, it is fundamental that the incumbent TOs' proposed network solutions are treated as the 'counterfactual' against which all market bids can be measured. To be confident that additional consumer benefit is being delivered, it is important that Ofgem develops transparent and robust Cost Benefit Analysis processes. These will ensure that Ofgem accurately and fairly measure the consumer value and system benefits of long-term regulated network assets, against potentially shorter-term market solutions.

<u>Proposals increase competition for skilled workers instead of accelerating job creation</u>

9.50 The ESO's proposals will simply increase competition across the UK for an already scarce and highly skilled workforce. This should be of significant concern to Ofgem as it risks significantly weakening the TOs' ability to retain a highly skilled workforce to operate and maintain the GB network. Following the recent COVID-19 pandemic, this is a time when the focus should be on accelerating further job creation as opposed to competing for skilled expertise already in the sector.

9.51 In summary, we believe that the industry should continue to work with the ESO in developing its ECP proposals. However, following submission of the ESO's ECP to Ofgem in February 2021, it is important that Ofgem assess the ESO's proposals in detail. As part of this assessment, Ofgem should consider the impact these proposals may have on the existing licensed roles and responsibilities of network operators. Ofgem should carry out detailed Impact Assessments and Cost Benefit Analysis processes to determine whether the ESO's early competition proposals will in fact deliver additional benefits to consumers, compared to the status quo arrangements. It should also be assessed whether the introduction of these more complex processes will add delays to the delivery of net zero infrastructure, which in turn will limit the ambitions of the UK, Scottish and Welsh Governments to meet its Net Zero targets.

9.52 As mentioned above, we do not consider that the opening up of the RIIO-T2 process control to include new early (or late) competition models provides investor certainty, nor does it highlight GB electricity networks as stable, predictable investment opportunities. Ofgem should use the duration of the RIIO-T2 price control to further develop the early competition policy and models and to work with the UK Government to introduce the necessary CATO legislation. It is inappropriate for Ofgem to revisit the projects of £50m+ identified in Business Plans, which have not been awarded baseline funding, to determine whether they should be delivered under any early competition model in RIIO-T2.

[200] Ofgem RIIO-2 Draft Determinations Core Document, July 2020, paragraph 9.2

9.53 Given the immaturity of the early competition policy, and the investor impact of opening up the price control framework, any early competition models proposed should not be introduced until RIIO-T3, at the earliest. This will allow stakeholders and network operators alike, time to engage effectively in the development of Ofgem's early competition proposals. This is particularly important, bearing in mind that delays to project delivery seem inevitable due to the complexity of tendering and awarding/negotiating of contracts/licences, in addition to the delays associated with enactment of relevant legislation. Such delays are likely to be costly to consumers and generators alike, and risk undermining the UK's ability to meet its Net Zero targets on time.

Chapter 10: Stakeholder Engagement

Introduction

10.1 Ofgem placed a great emphasis on its new enhanced stakeholder engagement in the RIIO-T2 process and we embraced the opportunity to weave this into our well-established Stakeholder Engagement Strategy which is outlined in detail within our Business Plan submission.

10.2 Ofgem's Enhanced Engagement Guidance for RIIO-2 explained how this new model would strengthen the consumer voice in RIIO-2. However, we are disappointed that Ofgem's Draft Determination on our Business Plan does not reflect the work we have undertaken to embed this model into our processes. Ofgem has failed to take into account the views and interests of GB consumers, network users, wider stakeholders, our independent Transmission User Group and Ofgem's Consumer Challenge Group.

10.3 Adopting Ofgem's enhanced engagement approach, we conducted a thorough and robust engagement process whereby we explored the challenges and costs we face in preparing our network to facilitate a net zero future for GB. With stakeholder input and support, we created the strategies, outputs, bespoke incentives and quantifiable benefits for consumers in our Consumer Value Propositions as set out in our Business Plan.

10.4 Consumers and stakeholders alike were clear on their concerns that we should be acting to minimise the impacts of climate change and maintaining the high levels of system reliability that they have come to expect. They understood the vital role our electricity networks must play in facilitating a swift and sustainable transition to Net Zero. We think that Ofgem's cost-saving narrative in the Draft Determination greatly oversimplifies the costs associated with achieving Net Zero and reducing the impacts of climate change. Ofgem's approach also fails to acknowledge wider economic costs (and potential benefits) for GB consumers. We have identified many of these costs and benefits through extensive conversations with consumers and stakeholders. This engagement resulted in a >80% acceptability of our plans across all GB consumers.

10.5 The stakeholders committed to this engagement process are also deeply disappointed by Ofgem's Draft Determination. In relation to the extensive work and hours dedicated by the Challenge Group and User Groups, Ofgem only state that the reports were "useful" (paragraph 3.5 of the RIIO-2 Draft Determination Core Document) with no greater explanation of how they were taken into account. Given that the Open Hearings had to be cancelled due to COVID-19, we would have expected these reports to have been even more important in providing insightful feedback to Ofgem. In particular, our independent User Group invested significant time and effort into the T2 process, an investment they feel has been ignored. We understand that they will be communicating their concerns separately to Ofgem.

Stakeholder engagement undertaken to inform our RIIO-T2 business plan

10.6 In its November 2019 Guidance on Enhanced Stakeholder Engagement, Ofgem explained that *"[t]he quality of stakeholder engagement that companies have undertaken will be a key consideration for us when we review the Business Plans that companies submit for RIIO-2*" (RIIO-2 Enhanced Stakeholder Engagement Guidance – Version 2, November 2019).

10.7 However, the Draft Determination makes no reference to any analysis of the enhanced stakeholder engagement underlying our Business Plan. It is therefore not possible to infer how, if at all, that engagement has been taken into account and evaluated by Ofgem.

10.8 Throughout our response, we highlight examples of investment, incentives and new initiatives that have been co-created with, and strongly supported by, our stakeholders, yet have been rejected by Ofgem in the Draft Determination. Specifically:

- Our Load and Non-Load capital expenditure was reviewed in detail by both the independent User Group and Ofgem's RIIO2 Challenge Group. Both groups highlighted the robustness of the expenditure justification, which has not been recognised by Ofgem.
- Our Output Delivery Incentives (ODI) proposals have been built up from our RIIO-T1 experience, developed in response to stakeholder feedback, and aligned with the RIIO-2 regulatory framework. We tested these proposals for their consumer value proposition (CVP), cost benefit analysis (CBA) and against consumer willingness to pay (WtP) and willingness to accept studies. All incentives were informed by stakeholder input. Strong stakeholder support for incentives has been disregarded by Ofgem in the Draft Determination.
- Ambition was noted by the User Group in their final report as an area where we could have gone further in our Business Plan submission. Significant reductions in capex by Ofgem are entirely contrary to the views of those independent experts.
- Our Telecommunications System Resilience programme has been disallowed. This programme comprises an essential investment providing resilient, cyber-secure infrastructure to enable an ever-smarter grid. It was independently scrutinised and supported by the independent User Group, who reported that: "*[s]pecifically, we challenged the costs regarding …. the telecommunications expenditures…For each of these specific challenges, SPT responded positively and the User Group is comfortable with the detail provided to justify the costs*".[201]
- Network Rail projects have been disallowed despite being informed directly by engagement with Network Rail and Transport Scotland and receiving strong stakeholder support. The uncertainty of the disallowance will inevitably lead to delays in the completion of the work. This decision will have a direct impact on the Scottish Government's transport plans and is a blow to their ambitions for Net Zero.
- Investment in replacement of end of life assets for the Torness Reactors has been disallowed due to risk of deferral. The criticality of these assets – in a nuclear power station – and their necessity for controlling system voltage has been demonstrated during the current pandemic. The RIIO-2 Challenge Group commended these initiatives, noting that: "*[i]n being very specific about their proposals, SPT gave us some confidence their Non Load Related Expenditure plans were robust and likely to be delivered with relatively low levels of substitution or change*."

Future Stakeholder Engagement Strategy and commitments

10.9 Ofgem has previously said that "the Business Plan must set out the company's approach to ongoing engagement in RIIO-2, including a strategy for engagement as well as a set of commitments to deliver the strategy" (RIIO-2 Business Plan Guidance – October 2019).

10.10 There is no reference in the Draft Determination to any analysis of our future Stakeholder Engagement Strategy or the series of commitments outlined in our Business Plan. We are therefore unable to ascertain how this strategy and these commitments have been judged by Ofgem. We spent a significant amount of time developing and evolving our Stakeholder Engagement Strategy, which we view it as a critical component of our T2 Business Plan.

Independent Transmission User Group

10.11 We are supportive of an enduring User Group, which challenges our delivery throughout the RIIO-T2 period. We proposed an enduring User Group as part of our RIIO-T2 Business Plan submission in both our 'Continuing to Engage with Our Stakeholders' and 'Output Delivery Incentives' chapters. We feel this group should remain at an individual company level, rather than operating across the sector. This would ensure regional and network specific issues can be appropriately challenged. Responses to the specific consultation questions are included below.

[201] Independent Transmission User Group Report, "SP Energy Networks RIIO-T2 Business Plan 2021-2026", page 27

Responses to Consultation Questions – Stakeholder Engagement

Core Questions

Q1. What role should Groups play during the price control period and what type of output should Groups be asked to deliver? Who should be the recipients of these outputs (companies, Ofgem and/or stakeholders)?

10.12 In creating our stakeholder engagement strategy for the RIIO-T2 delivery period, we were keen to include an ongoing role for the Transmission User Group. This group would have an ongoing role in assessing and influencing our activities and performance in relations to the needs of GB consumers, network users and wider stakeholders.

10.13 Our current User Group members have explained that they would not be particularly interested in an 'audit-only' type role, but would prefer to review the company's progress, alongside contributing their expertise to help shape ongoing delivery from a stakeholder perspective.

10.14 Based on our experience and member feedback, in our view, the User Group should meet quarterly and have three main roles during the price control period:

- Ensure the views of strategic stakeholders continue to shape our ongoing delivery plans and keep us informed of issues and challenges relevant to users of the transmission system – companies being the recipient of this feedback;
- Review performance in the delivery of RIIO-T2 outputs and provide feedback, which will be incorporated into our Transmission annual report – feedback being shared with Ofgem and stakeholders more widely; and
- Provide a strategic stakeholder perspective to re-opener applications – informing companies and Ofgem.

10.15 However, in light of the issues we discuss above in relation to the lack of transparency as to how Ofgem took into account the groups' reports, there needs to be greater clarity from Ofgem on how these groups' views would be considered as part of Ofgem's decision-making process. Further information is also required on any intended enduring role for Ofgem's Consumer Challenge Group during the RIIO-T2 delivery period.

10.16 We feel strongly that Company-specific groups are necessary, albeit with a channel for the respective chairs to exchange views and compare performance and approaches. This allows the group to be closer to the company's operations and creates a linkage into the presumed User Group role for the drafting of the RIIO-T3 business plans. Members from Company-specific User Groups would have a more comprehensive view on that company's track record and specific challenges.

Q2. What role should Groups take with respect to scrutinising new investment proposals which are developed through the uncertainty mechanisms?

10.17 For uncertainty mechanisms, we would be in favour of groups providing a stakeholder perspective on re-opener applications as it is generally not proportionate for extensive engagement on these given their scale and technical content. From a consumer and stakeholder representation perspective, this feedback could be considered as a component of the evidence presented in the re-opener application from SPT to Ofgem. However, the extent to which this was agreed to be a key component of evidence presented would need to be reflected in the relevant licence drafting (and any associated guidance) so that its role within the re-opener application process is formalised and given due weight.

Q3. What value would there be in asking Groups to publish a customer-centric annual report, reviewing the performance of the company on their business plan commitments?

10.18 We would question the value of this initiative. All TOs already publish a stakeholder-friendly annual performance report, which reviews the performance of the company against its business plan commitments. We have suggested that the User Group provides feedback to be incorporated within this report, rather than duplicating efforts. This also ensures all relevant activity and information is presented together.

10.19 We would also question what Ofgem would propose to do with the User Groups' feedback, given the lack of acknowledgement to their views in the Draft Determination. This perceived disregard for User Group feedback has the potential to undermine future willingness to participate in this process and it might be useful for Ofgem to address this point by highlighting how they (a) view/value User Group input and reporting; and (b) will make use of it in their own decision-making process.

10.20 It is important to remember that User Groups come at a cost to the consumer. Any additional requirements need to be meaningfully considered in light of the additional value they create. A customer-focussed report may have a disproportionate cost for time and effort versus the level of interest.

Q4. What value would there be in providing for continuity of Groups (albeit with refresh to membership as necessary) in light of Ofgem commencing preparations for RIIO-3 by 2023?

10.21 There is value in providing continuity of User Groups between price controls as it requires time and resource to bring members fully up to speed on the process and associated challenges. Setting up an independent User Group for the next 2-3 years will ensure they are in a strong position to establish or transition into a T3 User Group, when the appropriate time arises.

Q8. Do you agree that the Groups could have an enduring role to work with the companies to monitor progress and ensure they deliver the commitments in their engagement strategies?

10.22 Yes, please also refer to our answer to Q1.

10.23 As previously mentioned, it is important to remember that User Groups come at a cost to the consumer and any additional requirements need to be meaningfully considered in light of the additional value they create.

Chapter 11: Environmental Sustainability

Introduction

11.1 We welcome Ofgem's approval of our Environmental Action Plan ("EAP") and the associated funding as "justified on the basis of …expected effectiveness in mitigating adverse environmental impacts, as well as being value for money for consumers", and their statement that all companies met the Business Plan EAP minimum requirements.

11.2 However, notwithstanding Ofgem's agreement that our EAP is justified, some of the associated funding has erroneously been refused or reduced in the associated cost tables. Our opex costs have been reduced by £0.62m (a 20% reduction), our capex costs have been reduced by £1.36m and funding for areas where costs are uncertain and/or our understanding and processes are of low maturity, which was to have been provided via Uncertainty Mechanisms or financial incentives, has been rejected.

Opex Costs

11.3 With regard to opex costs (please also see Chapter 2, Expenditure and Outputs, Introduction and sections 1.1-1.4, particularly 1.2 final para), the erroneous reduction in funding impacts the following EAP activities (all of which relate to the delivery of Ofgem minimum requirements, as specified in the related Ofgem RIIO-2 Business Plan Guidance Appendix 2):

- Embodied carbon measurement
- SPT fleet electrification
- Carbon offsetting for high leakage assets
- Delivery of biodiversity and natural capital measurement tool(s)
- Embedding circular economy principles and delivering waste targets (including 95% landfill avoidance target)
- 80% of suppliers meeting supplier code of conduct
- Partner of Supply Chain Sustainability School
- Environmental data improvements - both to facilitate delivery of EAP Commitments and provide the necessary data for the Annual Environmental Report
- Staff competence and upgrading of skills, to deliver EAP Commitments.

Capex Costs

11.4 For capex items, Ofgem's application of a RIIO-T1 benchmark has resulted in the incorrect removal of some of the additional funding for SF6 free equipment (please see Chapter 2, Expenditure and Outputs, SPTQ12, Unit Costs item 4). Our proposal to install SF6 free equipment, at increased cost has been agreed by Ofgem (as explained in ET Annex paragraph 2.103) as well as being strongly supported by stakeholders (see our EAP: page 76, SF6 Strategy) and is an important part of reducing our carbon footprint. Our SF_6 reduction costs have been further reduced by £0.66m as part of Ofgem's review of our proposed circuit breaker investment programme (please see Chapter 2, Expenditure and Outputs, SPTQ12).

11.5 Our capex project SPNLT20122 Environmental: Considerate Constructors Scheme and CEEQUAL has been removed from the non-load cost table despite it being key to delivery of several of our EAP Commitments relating to suppliers and contractors:

- 80% of suppliers meeting supplier code of conduct
- Engagement with suppliers during contracts to reduce impacts and optimise benefits
- Target for zero environmental regulatory interventions and notifiable breaches
- Implementation of Pollution Prevention Plans for all future projects in RIIO-T2 and beyond
- Target to reduce environmental complaints.

11.6 As explained in the Executive Summary, we will continue to liaise directly with Ofgem to provide details of these funding impacts and any further information required by Ofgem in order to facilitate a resolution that adequately funds delivery of all of our EAP Commitments as set out in our EAP.

Incentives and Uncertainty

11.7 Certain commitments in the EAP were to be funded via the Legislative, Policy and Standards Uncertainty Mechanism (Environmental Enhancements) and the 'Additional contribution to the low carbon transition' ODI-F, which have both been refused (in the case of the UM, rejected). For details of our funding proposal please see our RIIO-T2 Business Plan, Environmental Sustainability section, (pages 35-47) and associated Annexes: Annex 7 Environmental Action Plan, Annex 12 Output Delivery Incentives and Annex 20 Uncertainty Mechanisms.

11.8 We do not share Ofgem's stated view that a reputational incentive to report on areas of low maturity will drive the required progress during the RIIO-T2 period, when levels of baseline allowance already represent significant challenge to delivery of baseline outputs.

11.9 The refusal of the ODI and UM impacts the following EAP activities:

- Compliance with any future changes in environmental legislation that take effect during the T2 period
- Remediation of historic land contamination such as may be found during the T2 period (which requires resolution in order to prevent pollution and associated breaches of statutory duties)
- Delivery of biodiversity 'no net loss' and 'net gain', and increase in value of natural capital (EAP Commitment in line with Ofgem minimum requirements and stakeholder feedback)
- Collaboration with supply chain to drive Scope 3 carbon reductions and wider environmental sustainability improvements, including circular economy and waste reduction [delivery of waste targets including 95% landfill avoidance] (EAP Commitment in line with Ofgem minimum requirements and stakeholder feedback).

11.10 Please also see the following sections in this response:

- Uncertainty Mechanisms (particularly the response to Q20)
- Output Delivery Incentives (particularly the response to SPTQ4).

11.11 We have already started to work with Ofgem to ensure that these impacts are fully understood by Ofgem and to address their concerns with the aim of reinstating both of these funding routes. We encourage Ofgem to engage in this dialogue to seek a resolution in advance of their Final Determination. We are concerned that if these funding routes are not reinstated, our inability to deliver these activities would significantly adversely impact on our local communities, and more widely on delivery of net zero carbon and protection and reinstatement of the natural environment.

11.12 In developing our EAP, we engaged with a wide range of stakeholders to guide our decision making and develop a well-balanced, fully justified plan that facilitates Net Zero and delivers the objectives outlined in both our Sustainable Business Strategy (available on SPEN's website) and Ofgem's minimum requirements (as specified in the related Ofgem RIIO-2 Business Plan Guidance Appendix 2). We responded to our stakeholders' feedback by making material improvements to our EAP over several iterations. Our resulting commitments and the corresponding costs we submitted as part of our Business Plan received broad support from our stakeholders and customers, the independent SP Transmission User Group and the Consumer Challenge Group, yet, as laid out above, many of these stakeholder-supported commitments are now at risk.

11.13 It is not clear from the Draft Determination how Ofgem has reconciled their position outlined in the Draft Determination with this stakeholder feedback. We welcome clarification on this from Ofgem and will engage with Ofgem further on this following issue of our Draft Determination response, as we are concerned that we will be unable to deliver stakeholders' expectations if these decisions hold.

11.14 We are also engaging with our key stakeholders to make them aware of our concerns and our view of the impact of the Draft Determination on deliverability of our commitments to them. We are encouraging them to make appropriate representation to Ofgem as part of this consultation process, to ensure that their views are heard.

Responses to Consultation Questions – Environmental Sustainability

Core Question

Q9. Do you agree with our proposal to accept the proposals for an ODI-R for BCF and the other proposals set out above as EAP commitments and to require progress on them to be reported as part of the AER?

11.15 Yes, we agree with and welcome the proposal to accept a reputational incentive relating to our Business Carbon Footprint and the commitments made in our Environmental Action Plan, and for progress on these commitments to be published annually in an Annual Environmental Report.

11.16 However, as explained above in this Chapter, some of the associated funding has erroneously been refused or reduced. Ofgem has explicitly stated in the Draft Determination Core Document (Chapter 4, paragraph 4.53) that they view the costs associated with delivery of the EAP as *"value for money for consumers"* and that "*we propose to include the funding for the EAP commitments ... in the respective TO's baseline allowance…"* (ET Annex, paragraph 2.83). We have outlined the activities affected by this error in reducing or refusing the funding associated with our EAP in more detail above in this Environmental Sustainability Chapter. We have also provided details directly to Ofgem (via conference call and emails week commencing 24th August 2020). Our ability to deliver our EAP Commitments will be proportionately affected by any funding reductions (for example a 23% reduction in the funding for electric vehicles will result in us being unable to implement electric vehicles on nearly a quarter of our fleet, against our target of 100%).

Electricity Transmission Annex

ETQ6. What are your views on our consultation position for the three electricity TOs' EAP proposals in RIIO-2 as set out in this document?

11.17 We welcome Ofgem's statement that 'we consider that the TOs' EAP commitments should lead to a significant improvement in the environmental performance of the transmission networks by 2025-26' (ET Annex, paragraph 2.81) and 'we were generally satisfied that most of the proposals in the network companies' EAPs are justified on the basis of their expected effectiveness in mitigating adverse environmental impacts, as well as being value for money for consumers' (Core document, paragraph 4.53) as we too believe our EAP delivers Ofgem's 'minimum requirements', and represents ambition and leadership in this area and value for money for consumers.

11.18 Please see the introduction to this Chapter above and our response to Q9 above for details of our views on the proposals for a reputational incentive for our Business Carbon Footprint and the introduction of an Annual Environmental Report.

11.19 However, as also explained above, notwithstanding Ofgem's agreement that our EAP is justified, some of the associated funding has erroneously been refused or reduced in the associated cost tables, despite Ofgem's statements that they view the costs associated with delivery of the EAP as "value for money for consumers" (Draft Determination Core Document, Chapter 4, paragraph 4.53) and that "we propose to include the funding for the EAP commitments ... in the respective TO's baseline allowance…" (ET Annex, paragraph 2.83). Our opex costs have been reduced by £0.62m (a 20% reduction), our capex costs have been reduced by £1.36m and funding for areas where costs are uncertain, and/or our understanding and processes are of low maturity, which was to have been provided via Uncertainty Mechanisms or financial incentives, has been refused.

11.20 In addition, as also explained above, the refusal of both our Legislative, Policy and Standards Uncertainty Mechanism (albeit with a request from Ofgem for further information, see SPT Annex, paragraph 4.7, Table 39) and our 'Additional contribution to the low carbon transition' ODI-F has removed all funding for some of our key EAP Commitments, including delivery of our biodiversity 'no net loss' and 'net gain', our natural capital net increase commitments and supply chain driven environmental sustainability improvements (further detail provided below and in our Chapters on Output Delivery Incentives, particularly SPTQ4, and

Uncertainty Mechanisms, particularly Q20). We will work with Ofgem to ensure that these impacts are fully understood and to address their concerns with the aim of reinstating these funding routes.

11.21 Where we have particular comments on Ofgem's consultation position, we provide them here:

Science-Based Targets (SBT)

11.22 We will provide an update on the development of our SBT, and our resulting interim target for the end of RIIO-T2, by the end of September 2020 as requested in ET Annex paragraph 2.87, and we will publish details of both in advance of the start of the RIIO-T2 price control period.

Reducing emissions from building energy use

11.23 In the ET Annex paragraph 2.90, Ofgem state:

> "*we propose to approve the baseline funding request by SPT. relating to this commitment subject to...providing further detail of their planned interventions. This is because we expect that the planned interventions would be economic overall given the results of several recent trials*."

11.24 However, in the Ofgem SPT Annex paragraph 3.58, the position is stated as:

> "*Approve. Justification provided within the paper is weak, but we recognise that this investment proposal forms part of the wider EAP and that progress would be reported in the Annual Environmental Report. It is due to this reporting requirement, ensuring that progress against this proposal is monitored and under-delivery recovered, that we are approving this scheme*."

11.25 However, Ofgem does not mention in this second location a need for further information nor clarification or what further information is required (as might be expected in this TO-specific document). Ofgem also issued no Supplementary Questions on this topic.

11.26 Following our review of the Technical Annexes provided, particularly Ofgem's consultant Atkins' review of non-load related expenditure, we believe that Ofgem's statement "*justification provided within the paper is weak*" is inaccurate and does not align with the view of their specialist consultant. The relevant Atkins report (EJP_SPT_SPNLT20142 EAP – Building Energy Reduction Measures) states that:

> "*The needs case is not considered valid from an engineering assessment perspective. Ofgem should consider this at a policy level rather than an engineering assessment*." (page 1, final paragraph in section 'Clear and Unambiguous needs case identified')

11.27 The Atkins report then states that "the options [for buildings energy reduction] are considered valid to lower the energy use of substation buildings. If the policy decision is to support SPT's Environmental Action Plan, then the chosen solution is proportionate to the purpose of lowering the energy use of substation buildings."(page 2, final paragraph in section 'Chosen solution proportionate to the identified needs case').

11.28 Given that Ofgem's specialist consultant considered that they had enough information on which to base this statement that the project is justified if Ofgem approve the EAP Commitments, we were initially not clear on whether Ofgem disagree with their consultant's views, and if so on what grounds, or whether they do in fact require further information and if so, what further information is sought? We have now spoken to Ofgem who have confirmed that further details of sites, types of intervention and programme are required, which we are now collating for submission.

Reducing emissions from operational and business transport

11.29 We are disappointed that Ofgem has not approved our 'Accelerating delivery of the low carbon transition' ODI-F - please see our response to SPTQ4 in our Chapter on Output Delivery Incentives.

11.30 Additionally, the costs to fund the electrification of our fleet have been erroneously reduced as they are contained within our indirect costs (since we lease our fleet) which have been subject to a blanket reduction. This reduction of 23% will significantly impact on our ability to deliver this EAP commitment – we will essentially not be able to electrify nearly a quarter of our fleet (our target being 100%). Please see our

Chapter 2 on Expenditure and Outputs for further details of our analysis of the funding decisions on our indirect costs. We will also liaise with Ofgem to ensure this issue is resolved as incentives are required for policy areas which are less mature to drive and focus performance.

Reducing embodied carbon in new network build

11.31 Ofgem state (ET Annex, paragraph 2.98) that:

> "*We encourage both SHET and SPT to strengthen their ambitions in this area by setting a target for reducing the amount of carbon embedded in new infrastructure during the course of RIIO-2*."

11.32 In so far as SPT is concerned (we make no comment on SHET), Ofgem is wrong in making this statement. We have committed (as detailed in our EAP) to "*establish a baseline (for embodied carbon) and set a reduction target by 2023*" (EAP, page 71, Table 15) so believe that we have already demonstrated this requested level of ambition in our EAP.

Reducing emissions of IIGs

11.33 In the ET Annex section on Insulation and Interruption Gases (IIGs), in response to our SF6 Strategy and associated funding of £7.7m, Ofgem state in paragraph 2.103 that:

> "*We are consulting on accepting the TOs' proposed IIG strategies as outlined above without any amendment. We are satisfied that by implementing their strategies, the TOs will reduce IIG leakage rates in RIIO-2 and also avoid a proportion of new SF6 additions on the network. This will contribute to fewer CO2e emissions than might otherwise be the case in the absence of the strategies and is, in our view, in the interests of current and future consumers*."

11.34 However, this £7.7m funding has been reduced by £0.66m as part of Ofgem's review of our proposed circuit breaker investment programme and by a further £0.43m as a result of Ofgem's application of benchmarking to some projects where we propose the use of SF6 alternatives at acknowledged increased cost (please see Chapter 2, Expenditure and Outputs, SPTQ12, including Unit Costs item 4.). This will impact our ability to meet the commitments in our SF6 Strategy and our BCF reduction target. SF6 emissions reduction is a cost-effective means to reduce our carbon footprint.

Electricity losses

11.35 We are pleased with Ofgem's position on our losses strategy, as outlined in our EAP namely:

> "*We welcome the commitments the TOs have made in their transmission losses strategies and propose to accept these without any amendment. We are satisfied that if they implement their proposed losses strategies, the TOs will make a positive contribution to an efficient level of transmission losses, which we consider is in the interests of current and future consumers*." (ET Annex, paragraph 2.109)

11.36 We particularly welcome Ofgem's decision not to include loss minimisation as a Licence Condition and agree with the justification given.

Embedding circular economy principles and improving supply chain sustainability, and sustainable resource use, recycling and waste reduction

11.37 Whilst we are pleased that Ofgem support our proposals in these areas we are concerned that our ability to deliver improvements in supply chain sustainability (be that related to carbon reduction or resource use/waste minimisation), and thus the achievement of our Scope 3 carbon and waste reduction targets, will be significantly hampered as a result of Ofgem's rejection of our 'Additional contribution to the low carbon transition' ODI-F which was to drive delivery of significant progress in these areas of low maturity, where costs are uncertain and there is risk associated with level of delivery – but where that significant progress is urgently required to avoid catastrophic climate change and biodiversity loss, and is demanded by our stakeholders. Our position on this issue is set out in more detail in our response to SPTQ4 in our Chapter on Output Delivery Incentives.

Enhancing biodiversity and natural capital

11.38 Again, we are pleased that Ofgem supports our proposals but are particularly concerned that our ability to deliver 'no net loss' or 'net gain' in biodiversity and an increase in the value of natural capital relied on the 'Environmental enhancements' part of the Legislative, Policy and Standards Uncertainty Mechanism - since the costs of such improvements are impossible to predict until sites are identified and baseline surveys undertaken, not to mention the current lack of a biodiversity metric. We will not be able to deliver these commitments in the absence of any funding. Please see our response to Q20, in our Chapter on Uncertainty Mechanisms for further information and our comments on this above. As noted above, we will work with Ofgem to resolve their queries.

Reducing pollution to the local environment

11.39 Our commitment to remove 318,000 litres of oil from our network is predicated on the replacement of oil-filled equipment with assets containing other substances. Whilst our proposals for such replacements have been accepted, Ofgem have reduced the funding request for our proposal, with which we disagree (please see Chapter 2, Expenditure and Outputs for details of our position on this funding reduction, particularly our response to SPTQ12). This target figure will need to be adjusted if the agreed deliverables and funding in the Final Determination do not allow replacement of the full 318,000 litres of oil.

11.40 Our commitment to drive environmental improvements on our construction sites is to be driven by the use of two respected Standards for benchmarking and improving the environmental performance of contractors: Considerate Constructors and CEEQUAL. However, our capex project SPNLT20122 Environmental: Considerate Constructors Scheme and CEEQUAL has been removed from the non-load cost table. We have made several EAP Commitments relating to contractors and construction site environmental improvements which rely, wholly or in part, on the use of these Standards to monitor and drive improvements:

- 80% of suppliers meeting supplier code of conduct
- Engagement with suppliers during contracts to reduce impacts and optimise benefits
- Target for zero environmental regulatory interventions and notifiable breaches
- Implementation of Pollution Prevention Plans for all future projects in RIIO-T2 and beyond
- Target to reduce environmental complaints.

Incentives

11.41 In environmental sustainability areas where our approach is reasonably mature and we can identify, with a reasonable degree of confidence, the activities required to deliver the degree of improvement expected by stakeholders - and the associated costs - we have done so and embedded these in our baseline costs.

11.42 In areas of low maturity there is inevitably less robust data and less clarity on the solutions and their costs. For these areas, it is not possible to meet the criteria Ofgem has used to assess our T2 Business Plan incentive proposals (namely a need for robust data and a requirement to accept the risk of a lack of delivery, with resulting financial penalties).

11.43 Yet these are exactly the areas that require incentivisation, to deliver global agreements as well as our own stakeholder expectations. Instead, the RIIO-T2 Draft Determination contains no incentivisation of low maturity environmental sustainability activities and, rather than facilitating an acceleration in this area compared to RIIO-T1, is a step backwards (RIIO-T1 had the Environmental Discretionary Reward which, although it had its problems, did drive progress in such areas). We do not share Ofgem’s stated view that a reputational incentive to report on areas of low maturity will drive the required progress during the RIIO-T2 period, when levels of baseline allowance already represent significant challenge to delivery of baseline outputs.

11.44 We are extremely concerned regarding this significant gap in mechanisms to accelerate progress in environmental sustainability and are seeking discussions with Ofgem to investigate opportunities to reach a resolution. In initial discussions with our key environmental stakeholders it is clear that they share our concerns. Please see our Output Delivery Incentives Chapter, particularly the introductory section, for more details on our concerns in this area.

11.45 We note Ofgem have accepted NGETs Environmental Scorecard proposal as a bespoke ODI-F. We believe there are merits in the mechanism that NGET have proposed and that elements of this proposal could be applied to our Additional Contribution to the Low Carbon Transition proposal. We would welcome the opportunity to work with Ofgem to develop this and present an updated proposal to them in advance of the Final Determinations.

Uncertainty Mechanisms

11.46 Our biodiversity 'no net loss', 'net gain' and natural capital value increase commitments were to be funded via the 'environmental enhancements' aspect of our proposed Legislative, Policy and Standards Uncertainty Mechanism, which has been rejected by Ofgem pending further information. Ofgem have not provided any details in the Draft Determination on the further information they have requested, and they issued no related Supplementary Questions. We consider this section of the relevant Annex to provide sufficient information on the need for these commitments to be funded in this way.

11.47 We are also engaging with Ofgem to ensure this issue is resolved. For further details please see our Uncertainty Mechanism Chapter 5 and particularly response to Q20.

ETQ7. What are your views on our consultation position for setting the expenditure cap for visual amenity mitigation projects in RIIO-2?

11.48 We have no comments on the expenditure cap for visual amenity mitigation projects in RIIO-2 as we do not foresee that we will be able to utilise this funding mechanism during T2. Only 3% of our network lies within eligible landscape areas and all identified mitigation projects will be delivered during RIIO-T1.

Chapter 12: Innovation

Introduction

12.1 We agree with Ofgem's statement in the RIIO-2 Draft Determination Core Document ("Core Document"), at paragraph 8.39, that innovation activity will help enable the transition to a smarter, more flexible and sustainable low-carbon energy system. However, the proposals in the Draft Determination are at odds with the need to urgently address the challenges of Net Zero targets. The Draft Determination represents a regression to an austerity position when it should recognise the importance of a green recovery from the COVID-19 crisis. The lack of focus on the importance of innovation is evident in the calculation of the Business Plan Incentive and Totex Incentive Mechanism, on which we provide further comments in the BPI and TIM Chapter forming part of this response to the Draft Determination. Innovative solutions are systematically penalised by these mechanisms with a resultant outcome which acts as a disincentive to network companies to employ business as usual innovation, which compounds the effect of very low rates of return.

12.2 Our innovation proposals have been extensively justified and, in the comprehensive quantitative analysis in Annex 6 of the Business Plan, been shown to provide consumer benefit. We are disappointed therefore that Ofgem have chosen to anchor innovation funding at RIIO-T1 rates. This does not recognise the urgency of the challenges facing the industry as we strive for Net Zero and is not reflective of the extensive planning that has been presented in the Business Plan.

12.3 Whilst we note Ofgem states in its Core Document paragraph 8.40 that innovation should be a core part of companies' business-as-usual activities and challenged companies to demonstrate more innovation in their Business Plans, we are disappointed that Ofgem has not recognised the extensive business-as-usual innovation activities that are explained clearly in both SPT's main Business Plan document and the Innovation Annex (Annex 6). Throughout our Business Plan, we highlight our strong track record of innovative solutions during RIIO-T1 and in Annex 6 of the Business Plan we show how we have adapted our business to further empower our people to drive further benefit for consumers in RIIO-T2.

12.4 We are surprised that the proposals we presented (in accordance with the Sector Specific Methodology Decision) relating to innovation roll out have simply been removed with no engagement and minimal commentary in the Draft Determination. We note that the Business Plan Data Template made provision for these costs and we provided extensive justification for their inclusion, including providing significant detail to demonstrate that the funding required is completely separate from that in RIIO-T1. We urge Ofgem to address this point and give consideration to an element of the innovation framework that it previously decided was relevant and valid.

Responses to Consultation Questions - Innovation

Core Questions

Q24. Do you agree with our proposals for the RIIO-2 Strategic Innovation Fund?

12.5 We agree with the high-level process Ofgem has proposed in respect of the RIIO-2 Strategic Innovation Fund in terms of setting a series of focused challenges. Our own internal innovation culture already applies a similar process (inviting our business to give ideas and comments towards clear challenges) which has resulted in an improved quality of submissions through an open call for ideas. We would comment that it is important to frame any proposed challenge or question properly and SPT has in-house expertise on how these challenges could be developed and governed and would offer this to support the SIF process.

12.6 On page 92 of the Draft Determination Core Document, in the context of requiring industry collaboration and third-party involvement in the Strategic Innovation Fund framework, Ofgem note that "*the Innovation Challenges will include requirements relating to the composition of consortiums and project partnerships that bid in for funding, where appropriate".* However, it is not yet clear on how consortiums would be formed and we require clarity on this point from Ofgem in order to consider and provide a more full response to this question. We assume that forming the project consortium will be within the scope and control of the project participants and not by any other mechanism.

12.7 It is not yet clear from Ofgem's proposals in the Draft Determination on the notice (form or period of time) that will be given for a SIF challenge. For similar processes, SPT would typically allow up to 12 months to develop a proposal to a point where we were satisfied that it is a high-quality submission that has been internally reviewed. We suggest therefore that there should be a clear 12-month pipeline of SIF challenges with a consultation period to inform this pipeline and support the shaping of the questions.

Q25. Do you have any comments on the additional issues that we seek to consider over the coming year ahead of introducing the Strategic Innovation Fund?

12.8 It will be necessary to clarify who sets the areas of focus for SIF - it is essential that TOs have their voices heard in this process. Clarity is required from Ofgem as to how Ofgem will balance potentially competing views on the priorities for SIF and to manage increasing uncertainty in the industry.

12.9 The ENA working groups have a strong track record of identifying innovation priorities and setting a clear strategic vision (informed by stakeholder views). It is not clear how (and whether) the SIF will build upon the previous work delivered by industry and the ENA (an example would be the ENA innovation strategy). Ofgem should clarify what documents, groups and guidance will be used to inform the SIF programme.

12.10 Practically, Ofgem will need to ensure that there is no funding gap in the transition from the Network Innovation Competition while SIF is being established. One suggestion to address this would be rollover of the Network Innovation Competition while SIF is established.

Q26. Do you agree with our approach to benchmarking RIIO-2 NIA requests against RIIO-1 NIA funding?

12.11 Benchmarking should still make allowances for the change in the energy landscape driven by political, economic, social, technological, legal and environmental factors. We disagree with that the only metric for establish the allowance should be the utilisation of RIIO-T1 spend (SP Transmission Annex paragraph 5.6 and Core document 8.71) which has reduced the £13.5m proposed in the Business Plan to £10m; we have answered this further for SPT Annex Consultation Q18 set out below.

12.12 We believe that RIIO-T2 should take into consideration not only the utilised spend of RIIO-ET1 Network Innovation Allowance ("NIA"), but also the year on year utilisation, our existing project management infrastructure, delivery to date and ambition for RIIO-T2.

12.13 The approach of constraining NIA to RIIO-1 levels does not reflect the urgency of the Net Zero challenges. A clear and detailed case has been set out in Annex 6 of our Business Plan to support the level of funding proposed in our Business Plan.

12.14 Our assumption is that benchmarking allows and assumes the memberships, services and partnerships are still eligible for NIA expenditure. Examples would be the Energy Innovation Centre, LCNI Conference and Utility Week Live conference.

12.15 The only expected changes we foresee are those regarding the implementation of the benefits table and Intellectual Property Rights guidance noted on page 99 of the Draft Determination Core Document and that clearer definitions of the terms being used across these documents should be made in agreement with License Network Operators (LNOs).

12.16 If Ofgem would not consider these additional factors in awarding the RIIO-E2 allowance, we request that SPT's proposed funding allowance in our Business Plan (£13.5m) is approved subject to a review 24 months into RIIO-T2 to demonstrate eligibility.

Q27. Do you agree with our proposal that all companies' NIA funding should be conditional on the introduction of an improved reporting framework?

12.17 We make clear in our business plan that we support enhancement of the reporting framework and SPT will integrate the ENA Benefits Reporting Framework into its existing internal reporting practices to support this. For the avoidance of doubt, SPT is responsible for its own contribution to supporting the framework and NIA funding is not conditional on the support of other LNOs. We expect that the function and co-ordination of the ENA Innovation Manager Working Group will need to adapt in response to this to ensure that all LNOs continue to report in a consistent manner on this topic.

Q28. What are your thoughts on our proposals to strengthen the RIIO-2 NIA framework?

12.18 We support the decision to retain the Network Innovation Allowance (NIA) in RIIO-T2 as the existing allowance has encouraged increased engagement with third parties including SMEs and academia and has addressed critical system issues that required innovative solutions. NIA funding has also on several occasions been used to test concepts which were then further developed in larger NIC projects; SPT is a leading licensee in this regard (please refer to our response to SPTQ18.

12.19 We disagree with Ofgem's proposal as set out in the Draft Determination Core Document to tighten the scope of the NIA framework to energy system transition ("EST") and consumer vulnerability. While both topics are very important and should be addressed through NIA, limiting the scope of NIA only to these areas will create an innovation gap for projects which require funding to overcome significant risks before they are adopted into business as usual or only deliver consumer benefit in the longer term.

12.20 It should be recognised that NIA projects focused on longer-term energy system transition challenges are more likely to be of a lower Technology Readiness Level ("TRL"), which makes tracking of benefits more challenging. We strongly believe that if NIA is being steered towards lower TRL projects, this will create a funding gap for technology with the potential to bring significant network and customer benefits which cannot be funded by NIA. In addition, steering NIA to lower TRL technologies is contradictory to the implementation of the new ENA-led benefits reporting framework, as it is not realistic to consider financial benefits as the primary output for lower TRL projects given that these inherently have less certainty of success than higher TRL technology. We therefore oppose this approach, if the sole focus of projects is to be EST or consumer vulnerability to the exclusion of other innovation themes.

12.21 From examining best practice innovation in other sectors, we believe there is a need to ensure a balanced portfolio of innovation projects in terms of TRL/maturity. We propose that innovation funding should be proportional based on the stage of the innovation maturity with an agreed proportion of the funding available for higher TRL network deployments and demonstrations and an agreed proportion of funding for low TRL early stage research and development ("R&D") activities to support the longer-term EST. SPT encourages Ofgem to retain the flexibility of funding high risk, strategically important projects that demonstrate significant benefits to consumers, but do not specifically fall under EST or Customer Vulnerability.

12.22 Furthermore, we disagree with the proposal as set out in Paragraph 8.85 of the Draft Determination Core Document to remove eligibility for trialling commercially available products from overseas. Electricity networks vary considerably in design (including voltage level differences), policy, standards (technical and safety), materials used and operational practice. As such, there is a variable degree of risk associated with trialling new technology on the GB networks irrespective of the success of that technology elsewhere internationally. As such, we oppose the removal from the scope of the NIA funding should the decision preclude either: development work required to adapt commercially available technology to the GB networks should the initial technology demonstration be unsuccessful; or investigative work to establish the risk of applying such technology to the GB networks.

Q29. Do you have any additional suggestions for quality assurance measures that could be introduced to ensure the robustness of RIIO-2 NIA projects?

12.23 We suggest that each LNO confirms their internal governance process and shares the best practices of this. In addition, we would suggest that the ENA play an active role in the regular review of the UK project portfolio to ensure best practice and alignment with the benefits reporting mechanisms.

Q30. Do you agree with our proposals to allow network companies and the ESO to carry over any unspent NIA funds from the final year of RIIO-1 into the first year of RIIO-2?

12.24 This is welcomed but further clarity should be given by Ofgem as to what governance is applicable to the projects and funds and whether each project should be individually justified or re-registered in any way.

Q31. Do you agree with our proposal that all work relating to data as part of innovation projects funded via the NIA and SIF will be expected to follow Data Best Practice?

12.25 We agree with NIA and SIF following Data Best Practice, assuming that the correct risk assessment and triage has been applied. This would be carried out as part of the data triage process which has been developed via the ENA Data Working Group and aligns with Data Best Practice.

<u>SPT Questions</u>

SPTQ18. Do you agree with the level of proposed NIA funding for SPT? If not, please outline why.

12.26 This approach is does not reflect the urgency of the Net Zero challenges. A clear and detailed case has been set out in Annex 6 of our Business Plan to support the level of funding proposed by SPT.

12.27 Ofgem state in the Draft Determination – SPT Annex, Par 5.6 that they "are unconvinced that an increase in NIA funding for RIIO-ET2 is justified" as SPT did not fully utilise NIA funding in RIIO-ET1. We would disagree and would note that we have utilised on average 84% of our RIIO-T1 allowance, an allowance that was a percentage of annual turnover with no capacity to allow overspending. Our utilisation figures reflect careful management of consumers' money and mitigating uncertainty.

12.28 Furthermore, as part of our adjusted structure, we have a strong pipeline of projects and are on track to fully utilise the allowance for the remainder of RIIO-T1. Therefore, we would disagree with the proposed level of funding and stand by our original request for NIA funding as per our business plan.

12.29 We have already developed a planned project pipeline and the NIA allowance proposed in our Business Plan would result in more projects being delivered in the same prudent manner within RIIO-T2, delivering £4 of benefits for every £1 invested through this mechanism as stated within our business plan.

12.30 However, we note that SPT's funding proposal for rolling out proven innovation, as provided for in the Sector Specific Methodology Decision, paragraph 10.27, has been disallowed in its entirety from the Draft

Determination. SPT provided a detailed response to SQ SPTL_SQ_POL_12 but there was no subsequent engagement by Ofgem with SPT on this topic and we are surprised that there has been no discussion on this point with SPT. Annex 6 of the Business Plan sets out clear and detailed justification for this funding and we are concerned that it has been disregarded with no explanation.

12.31 Ofgem states "*companies should not rely solely on additional innovation stimulus funds but should fund more innovation in RIIO-ET2 as BAU using their totex allowance*" (SPT Annex paragraph 5.6). We agree with that companies should not solely rely on such funds and SPT has a large body of innovation projects which are being delivered under business as usual without using the NIA allowance which demonstrates this is standard practice for SPT:

- SPT has a strong track record of BAU innovation which is referenced in the Core Document (page 14) and Annex 6 of our Business Plan.
- SPT can demonstrate its commitment to realising innovation through Business as Usual activities through our focused Culture of Innovation internal campaign.
- This was launched so that our business is aware of the ongoing innovation activities and realises the opportunities to innovate in their role.
- Through this campaign, we have also launched a series of specific challenges to our business to tap into the expertise of our staff, with the strongest ideas being delivered as part of our business via TOTEX allowances. This was detailed as an ongoing activity throughout RIIO-T2 in Annex 6 of the Business Plan.

12.32 The Draft Determination states that "*without detailed evidence of a change in structure and delivery of innovation within the organisation*" there is no justification for an increased allowance. Notwithstanding our first point, there is in fact evidence of continual improvement in the delivery of innovation in the company:

- We have a robust process in place to monitor, report and track spend and benefits as explained in Section 11.7 of Annex 6 of our Business Plan.

- We work closely with other key industry partners and internal colleagues to continually improve this process.

- Our structure is made up of our Project Management Office (PMO) function and our Innovation Board:
  - Our Innovation Board are responsible for evaluating proposed projects, ensuring it meets NIA governance and our internal project criteria (e.g. an active business sponsor must be confirmed). It is made up of senior staff to ensure the wider business is represented in key decision making.
  - Our PMO is responsible for the identification and development of the projects. The PMO and business sponsors will make justifications for project eligibility including forecasted benefits.

12.33 For approved projects, the PMO has implemented a robust and consistent process to manage these projects through development to its transition into our business as usual operations; this includes reviewing the forecasted spend and benefits via our NIA Tracker Tool. Annual utilisation is monitored via this tool.

12.34 In addition, we wish to address the comments contained in table 41 of the SP Transmission Annex:

> *'Much of the discussion of innovation within BAU activities is focused on the rollout of past innovation to deliver efficiency savings, rather than clearly evidencing plans to do new innovation. We also agree with concerns from SPT's UG that the Business Plans' overarching focus on reliability and reducing risks is at odds with a strong desire to innovate within BAU activities*. '

12.35 However, the same report by SPT's User Group also states "SPT has made it clear that it deliberately errs on the side of reliability rather than taking a higher level of risk in innovation. Whilst we advance a case for a higher level of ambition, we recognise that the choice SPT has made reflects the priorities of the customers." The report also supports the level of funding proposed in the business plan, stating "In respect of the Customer Value Proposition for innovation SPT note that they are expecting a return on investment of £73m. The User Group were pleased with this level of benefit, in particular when compared to the level of investment required to attain it (£18.65m)"

12.36 In Annex 6 of the Business Plan, the proposals for "BAU" Innovation and are described, distinct from those to be funded by NIA or rollout funding. These are collated in Annex 9.

12.37 The following evidences new innovation being embedded within SPT, demonstrating that the funding set out in our Business Plan is not designed to deliver efficiency savings for the benefit of SPT, but instead is to conduct further work to allow these projects to be embedded within SPT and to realise value for our customers.

12.38 In this response, we request that Ofgem reinstates the £5.2m rollout funding proposed in the SPT RIIO-T2 Business Plan. SPT can clearly demonstrate:

i. The track record and strong commitment of SPT's leadership in innovation

We demonstrated, within **Section 6.1 Innovation Benefits and Expenditure** of SPT RIIO-T2 Business Plan Annex 6 (Innovation), that SPT went through a clear, strategic and successful journey over RIIO-T1 and established our leading position among the European Transmission System Owners. Each relevant Engineering Justification Paper presented with the Business Plan for the major investment details the proven innovations that will be applied as business as usual, with no request for innovation funding.

SPT has been proactively working with our innovation partners and built a strong portfolio over £60million by leveraging Network Innovation Competition[202], EPSRC [203](the academic part of Innovation UK), Innovate UK (supporting SMEs) and European Horizon[204] 2020 funding. **Each £1 of NIA leveraged nearly £6 within SPT's effective management portfolio leading to a benefit of £15 per £1 leveraged**. It is also a clear evidence that the previous NIA settlement under RIIO-T1 is far from enough to meet the needs of SPT set out in the Business Plan to deliver innovation in the coming period.

ii. An in-depth understanding of pros/cons of current innovation and the overreaching strategy

Ofgem (in par 5.6) want to see more innovation carried out as BaU, but there will still be gaps and risks that must be covered through innovation projects. "*We cannot turn their ideas into the products and services on which the industries of the future will be built***."** [205] **-** the UK government and the key stakeholders of innovation have recognised that while the UK is good at the initial phase of innovation, more is required regarding the gap between project demonstration/ development and the commercialisation of innovation to realise its full potential. There is still inherent risk in deploying innovations that are not fully proven on the electricity transmission system that requires funding and significant potential customer benefit that justifies further exploitation. SPT specifically targets projects and opportunities only where there is a clear benefit to consumers that justifies the investment.

SPT is well placed to deliver this gap and support this as we have significant of first-hand experience, with in-depth understanding and a resulting capability to provide strong support as indicated by the delivered projects described above in point 1.

iii. The definition of 'new' within Innovation

The existing RIIO NIA governance and the ongoing mechanism has defined innovation as the technology, process and/or commercial arrangements that are not deployed on the UK networks. (***i.e. unproven in GB, or where a method has been trialled outside GB the Network Licensee must justify repeating it as part of a Project***[206]). Electricity networks vary considerably in design (including voltage level differences), policy, standards (technical and safety), materials used and operational practice globally. As such, there is a variable degree of risk associated with trialling or rolling out new technology on the GB networks irrespective of the success of that technology elsewhere internationally.

[202] VISOR (2013), FITNESS (2015), Phoenix- Synchronous Condenser (2017), Distributed Restart (2018)
[203] Collaboration with Imperial College, the University of Manchester, Warwick University, Oxford University, Strathclyde University, Glasgow University, Napier University in Edinburgh, Edinburgh University
[204] https://www.spenergynetworks.co.uk/pages/migrate.aspx; https://www.h2020-migrate.eu/about.html
[205] https://www.gov.uk/government/publications/industrial-strategy-building-a-britain-fit-for-the-future
[206] Ver 3, NIA Governance Paragraph 3.6

Therefore, we oppose the removal of funding should the decision preclude either development work required to adapt commercially available technology to the GB networks should the initial technology demonstration be unsuccessful; or investigative work to establish the risk of applying such technology to the GB networks.

SPT has demonstrated in Annex 6 of the Business Plan that its proposed approach of innovation by targeting the strongest focus areas (through re-visiting the existing portfolio of over 1000 UK projects at a TRL ready for development) is a continued, robust and integrated approach:

- Leveraging existing projects into further developments with clear purpose and identified benefits has been a strategy which has yielded significant consumer benefit by SPT in RIIO-T1.
- Our proposed approach is in line with a recognised need declared by the UK Government
- Innovation can be required to embed technology and processes beyond a trial or demonstration

This approach will involve significant innovation, project management and business understanding to uplift the TRL. It is critical to allow further TRL uplift of the areas presented in the SPT Business Plan to extend the current innovation cycle.

SPT has also carried out a detailed assessment (presented in Annex 6 of the business plan) of each technology and assigned monetary value to the expected benefits. Therefore, whilst the terminology of ‘roll out’ does not reflect our intention of uplifting existing completed demonstration projects, it will bring the innovation benefits in a timely manner for our customers**. We therefore request the reinstatement of the corresponding £5m for this purpose.**

Chapter 13: Impact of COVID-19

Introduction

13.1 This section covers the COVID-19 question and its wider implications.

Responses to Consultation Questions – Impact of COVID-19

Core Question

Q43. Do you think we need specific mechanisms in RIIO-2 to manage the potential longer-term impacts of COVID-19? If yes, what might these mechanisms be?

13.2 The following provides a response to Draft determination question 43 and the wider implications of historic, current and future COVID 19 restrictions on the deliverability and costs associated with our RIIO-T2 plan COVID-19 is impacting the delivery of the T1 plan in two ways:

- Our ability to deliver against previous timescales due to government restrictions, supply chain availability and network access for outages
- The cost of activities due to additional precautions required on site and additional costs as a result of recovering the existing programme

13.3 We anticipate that these two areas will have an impact on the initial year of RIIO-T2, and if current restrictions continue, or further lockdowns are imposed, this may have longer-term consequences which Ofgem will need to engage with TOs to consider how these are addressed.

13.4 With specific reference to Draft Determination Core Document paragraphs.

- Para 12.1 and associated footnote 149; Whilst we accept that there may be differences to the effect of COVID on the progression of activities within the Distribution sector we strongly dispute that the effect on the Transmission sector works is significantly less than that on Distribution. Transmission works are more weighted towards construction type activities which involve a wider range of suppliers and 'Just-in-time' delivery of materials which were significantly affected by the initial lockdown and are likely to have suffered longer term reductions in business confidence and resilience.
- Para 12.3; We agree that SPT should not and would not compromise Health Safety Quality or Environmental compliance and Standards in the progression of our Regulatory Obligations however; as will be detailed further in this response, we maintain that our ability to delivery our works as planned within our allowable costs has been compromised.

Deliverability and timescales

13.5 Ofgem should fully consider the current and historical differences associated with UK and Devolved Government strategies with respect to the application of COVID-19 restrictions on construction works. In particular, the differing definitions of "essential work" in Scotland compared to England and Wales. Beyond formal interpretation of essential works SPT have a duty of care to assess all risks including and most critically the risk to health of our employees and wider supply chain. Such assessments have resulted in the postponement, delay or curtailment of construction and O & M activities which could have been interpreted as essential. A high proportion of our activities are delivered directly or supported by a wide and varied supply chain which ranges from global manufacturers to local SMEs, all who will have been impacted widely by the COVID –19 pandemic. Impacts may include, but not limited to, financial stability of such organisations following the prolonged lock down, and overall capability. Whilst we hope that short term effects have lessened, we cannot discount the possibility of long-term reduction of the overall resilience of our supply chain.

13.6 COVID-19 has had, and will continue to have, a negative impact on the delivery of SP Transmission's RIIO-T2 programme of works. This is because the sequence of works between RIIO-T1 and RIIO-T2 are inextricably linked. This means that delays to RIIO-T1 works significantly risks delivery of works associated with RIIO-T2.

13.7 Within the context of RIIO-T1, we have worked tirelessly to mitigate the impact of the initial lockdown and facilitate the restart and continuation of our RIIO T1 programme of works. Changes have been necessary to our planned network access which account for the cancellation, postponement or change to planned dates of some 122 outages (see Figure 10). These are due to restrictions on outages to reduce the risk on the network for critical sites such as hospitals, and reducing demand requiring the full system to be available to the ESO to manage the impact. Projects were also impacted as a direct result of supply chain and delays resulting from the unavailability of supplies and materials. Ongoing onsite management of work activities related to social distancing measures continue to impact our programmes of work and onsite productivity.

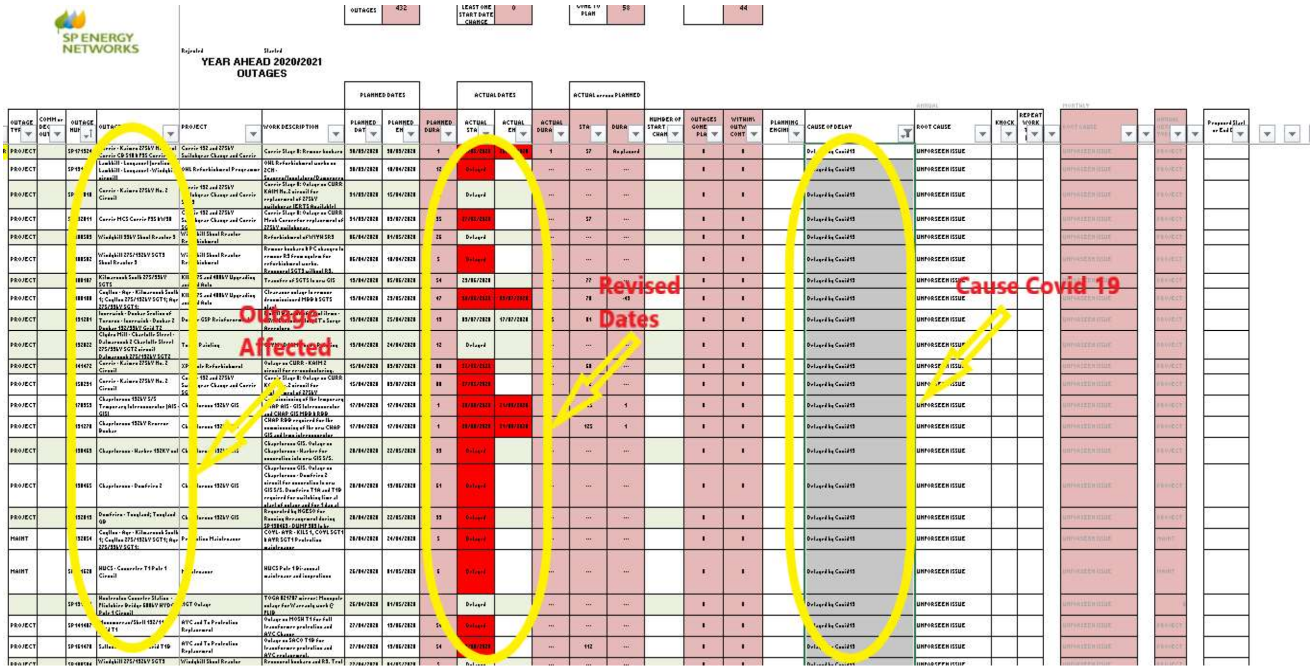


Figure 10: Sample SPT Outage Tracker

13.8 The delivery of our RIIO-T1 programmes following lockdown and ongoing onsite restrictions continues to be impacted. All contingency time in our RIIO-T1 programme has been lost. Furthermore, we are unable to provide certainty of any programme recovery in the event of further delays as a result of localised or national restrictions or lockdowns. Lockdowns may not only impact the location where works are taking place, but they could also impact contractors or other elements of the supply chain that are located in the vicinity of such a lockdown.

13.9 Our RIIO-T2 programme of works was developed taking full and detailed consideration the continuation of known RIIO-T1/T2 crossover works but was fundamentally based on the assumption of substantial completion of all RIIO-T1 projects before the commencement of the RIIO-T2 onsite works. Our confidence of completion of RIIO-T1 works was based on and can be evidenced by the excellent progress being made on all projects prior to the onset of the COVID-19 lockdown and our track record of delivering projects to plan.

13.10 Projects of note1 and significantly affected by COVID-19 delays are:

- Kaimes 275 kV Switchgear replacement project
- Kincardine 275kV Substation Flood prevention
- Kilmarnock South TORI 143
- Chapelcross 132 kV switchgear replacement
- Shrubhill Transformer Replacement (33kV cabling only)

13.11 Delayed completion of these projects is directly attributable to COVID-19, requiring rescheduled network outages both out with normal outage windows and in parallel with other RIIO-T2 project outages. Although individual project risks have been assessed to the greatest extent possible, there is an inevitable overall increased network risk attributable to these works and corresponding potential for associated Energy Not Supplied (ENS) penalties. This elevated risk is directly attributable to the effects of COVID-19.

13.12 Should any T2 (or delayed T1 works) commence and subsequently be delayed or suspended during network outage/ depletions or need to be returned to service temporarily as a result of further local of national lockdowns or restriction of activities, then this again, has the potential to increase our expose to ENS penalties in addition to overall increases in projects' costs.

13.13 The probability of delayed RIIO-T1 projects impacting on RIIO-T2 works along with associated level of deliverability risk is now elevated above those assessed and contained within our original RIIO-T2 submission. There may be the requirement to re-sequence outages around fixed or contracted deliverables, taking consideration of the elevated network risk and potential generation constraints of outage works during winter periods. In this instance it is not always technically feasible to mitigate issues simply by accelerating projects and maintain full delivery of our overall plan within the T2 regulatory period. Due to the need to sequence outages, taking consideration of the higher network risk and potential generation constraints of outage works during winter periods, it is not always technically feasible to simply accelerate projects and maintain full delivery of our overall plan within the T2 regulatory period.

13.14 We would welcome further engagement with Ofgem to discuss how any such delays or non-delivery should be assessed.

T2 Costs

13.15 COVID-19 will affect the cost of delivery of our RIIO-T2 portfolio of baseline plan works and those works covered by reopeners or uncertainty mechanisms. Current onsite social distancing protocols including, extended welfare provisions to cater for social distancing, protection measures such as additional PPE, and revised working arrangements have a direct impact and consequently require extensions to programmes. Examples of mitigation against these issues, which affect the overall delivery programme of works, include split shift working arrangements, extension of normal working days or weekend working and remote verification or witnessing of key tasks. This in turn will be reflected in the overall cost of delivery.

Safety critical meetings associated with site induction, daily site activities and setting to work briefings need to be duplicated. In this example attendee room capacity of 12 reduced to 3

Figure 11: Changes in Working Methodology

13.16 For all new contracts, where possible, we have contractually ring-fenced the ongoing costs of compliance with current COVID-19 restrictions to ensure that these apply only during periods where current COVID-19 social distancing requirements and work protocols are in place. This is expected to create further uplifts of rates within the future tenders.

13.17 Due to the current uncertainty it is impossible to forecast the overall impact and duration of ongoing COVID–19 restrictions on the overall delivery cost. Despite the difficulty in ascertaining full costs, we propose that any additional costs, where substantial and evidenced, warrant further engagement and dialogue to take account of these.

13.18 The impact on RIIO-T2 policies such as PCDs, Volume Driver rates allowances and the Large Project Delivery Incentive would all need to take into account such an impact. We do not believe that something as simple as a re-opener would be sufficient to address additional costs due to the complex nature of COVID-19 impacts.

13.19 Such discussions would need to take account of the risk associated with further waves of infection and a return to a national or local lockdown of work activities in addition to how this risk is accounted for and the consequential effects on our suppliers and overall project costs

Chapter 14: Digitalisation

Introduction

14.1 This section covers the digitisation questions.

Responses to Consultation Questions - Digitalisation

Core Questions

Q5. Will the combination of the two proposed Licence Obligations support the delivery of a digitalised energy system and maximise the value of data to consumers?

14.2 Yes, the proposed licence obligations for Digitisation and Data will drive efficiency in the energy system and lead to a modernised energy system that maximises value to consumers. Digitalisation and data are key for the delivery of a decentralised and decarbonised energy system, and we would welcome further moves to drive investment in this area as part of the UK's net zero ambitions.

14.3 While the roadmap towards Net Zero may be unclear at this stage, Ofgem's Draft Determination against SPT's Non-Operational IT and Telecoms business plan is disappointing. We have ambitious plans for the digitalisation of our activities and the use of data to drive our operations. We have played a significant role in the ENA's Data Working Group and are determined to implement an agenda that will deliver value to consumers whilst enabling a green recovery from the current COVID situation.

14.4 This will not be achieved without leadership from Ofgem and we would welcome further discussion on how best to deliver our ambitions in this area.

Q6. Do you agree with our proposed frequency for publication of updates to the digitalisation strategy and the digitalisation action plan, respectively?

14.5 Yes, we agree with the proposal to publish updates to the digitalisation strategy every 2 years, and updates on the digitalisation action plan every 6 months. In accordance with the guidance around data interoperability, we would welcome initiatives to drive system wide digitalisation activities with coordinated action between network companies and across the wider energy sector.

Q7. What kinds of data do you think should comply with the data best practice guidance to maximise benefits to consumers through better use of data?

14.6 Key data for "presumed open" should be information relating to network assets: location, classification/identification, capacity, utilisation, etc. Visibility over this information across the whole energy system will enable decisions to be taken to facilitate decarbonisation. We also recognise that initiatives in this area can deliver a wider benefit to society and that work is required to identify the key data users and use cases that should be prioritised. This aligns with initiatives that SPEN is actively pursuing, for instance around the optimal locations for electric vehicle charge points.

Chapter 15: Interlinkages and CMA

Introduction

15.1 This section covers the questions on interlinkages and on CMA posed by Ofgem

Responses to Consultation Questions – Interlinkages and CMA

Q39. Do you have any views on the interlinkages explained throughout this chapter?

15.2 We have set out our position on Ofgem's approach to identifying the interlinkages in our response to Q39. In light of this, we have not assessed Ofgem's high-level view of the interlinkages in Chapter 11 in any great detail. We would only raise one comment at this stage (set out in the next paragraph) in relation to Ofgem's high-level views on the links between their proposals for ongoing efficiency and innovation funding. Our response to this question should not be taken as agreement with the other high-level interlinkages Ofgem has set out.

15.3 The innovation funding from RIIO-T1 has resulted in cost savings already built into the baseline, so the application of ongoing efficiency linked to innovation funding results in a double counting of cost reductions. The shorter price control period effectively means that there will be no efficiency benefits in RIIO-T2 from in-period innovation funding. Any efficiency benefits derived from innovation funding will result in lower baseline costs in RIIO-T3. There is therefore no practical linkage between innovation funding and the application of ongoing efficiency reductions as innovation efficiencies are removed from the next period's baseline costs.

Q40. Are there other interlinkages within our RIIO-2 package that you think are relevant to the three pillars identified in this chapter?

15.4 Ofgem state that the purpose of Chapter 11 is to "provide a high-level view of how the different elements of the RIIO-2 price control framework interact with each other."[207] Ofgem states as follows:

> "*We provide several examples below in order to illustrate the nature of the interlinkage categories. The **examples are not an exhaustive list** of every way in which individual aspects of our overall price control decision may be linked to every other aspect. It would **not be proportionate** to attempt to do this here. Instead, we provide these examples to help licensees and other stakeholders to gain a better understanding of how our proposed price control is comprises a number of interlinked elements*." (emphasis added)[208]

15.5 Ofgem have then asked respondents to confirm, in the extremely tight timeframe available to respond to the Draft Determination, if there might be any other relevant interlinkages. This approach is wholly unsatisfactory and goes against the approach expected by the CMA.

15.6 In particular, in its open letter to Ofgem dated 30 October 2019 (the **CMA Open Letter**)[209], in relation to interlinkages, the CMA state that they "*encourage regulators to explain these interlinkages, and the reasons for them, in their decision documentation*".[210] The CMA also stated "*Where there are such **interlinkages described clearly by the regulator**, we would encourage appellants to explain why the component under challenge is wrong having regard to the interlinked aspects of the decision*"[211] (emphasis added). In the

[207] Ofgem, Draft Determination: Core Document, para 11.2
[208] Ofgem, Draft Determination: Core Document, para 11.10
[209] Available at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/844218/CMA_Response.pdf
[210] CMA Open Letter, para 14
[211] CMA Open Letter, para 15

British Gas Trading and Northern Powergrid's appeals to the CMA, the CMA was also clear that they expected Ofgem to highlight and set out any interlinkages in its response in the first instance.[212]

15.7 The CMA therefore clearly expects that any regulator which believes there to be interlinkages in a price control package should clearly describe and explain the reasons for the interlinkages in their decision documentation. Ofgem has not done this. Instead, Ofgem expressly state they have only provided some high-level examples which are not exhaustive and attempt instead to shift the burden for identifying the remaining interlinkages to TOs (and, again, even then within an extremely tight timeframe).

15.8 We do not consider it would be appropriate for respondents to complete this exercise for Ofgem. Ofgem designed the price control package, and it is therefore appropriate that Ofgem clearly describes any interlinkages. This is even more so given the numerous areas of the Draft Determination in which Ofgem has failed to provide the transparency necessary for TOs to understand its methodology. Ofgem therefore need to set out a clear explanation and reasoning for the interlinkages in their Final Determination. If Ofgem fails to do this then we consider Ofgem could not rely on any arguments about interlinkages in any future CMA appeal.

Q41. Do you have any views on our proposal to include a statement of policy in Final Determinations that in appropriate circumstances, we will carry out a post appeals review and potentially revisit wider aspects of RIIO-2 in the event of a successful appeal to the CMA that had material knock on consequences for the price control settlement?

15.9 SPT does not support this proposal. It appears to us that Ofgem is seeking to subvert the CMA appeals process and is proposing steps which could result in a 'claw back' of the benefit of a successful appeal in ways that would be unlawful.

<u>Existing Statutory Framework</u>

15.10 As Ofgem is aware, the basis for bringing appeals to the CMA against licence modifications by Ofgem (including price controls) is section 11C of the Electricity Act 1989 (**EA89**). Section 11C provides that an appeal lies to the CMA against a decision to proceed with the modification of a condition of a licence under Section 11A of the EA89.

15.11 Sections 11C to 11H of the EA89, along with the Energy Licence Modification Appeals: Competition and Markets Authority Rules published by the CMA in October 2017 (the **Rules**), set out the process for appealing an Ofgem licence modification decision to the CMA.

15.12 Under section 11F of the EA89, where an appeal is in relation to a price control decision, the CMA must do one or more of the following:

a. quash the decision (to the extent that the appeal is allowed);
b. remit the matter back to the Authority for reconsideration and determination in accordance with any directions given by the CMA;
c. substitute the CMA's decision for that of the Authority (to the extent that the appeal is allowed) and give any directions to the Authority or any other party to the appeal.

15.13 A determination made by the CMA on an appeal will be contained in an order made by the CMA. That order is binding on Ofgem. Where the CMA gives directions to Ofgem on an appeal, Ofgem "*must comply with it*" (Section 11F(5) of the EA89).

<u>Ofgem's powers and duties on appeal</u>

15.14 In light of the overarching statutory framework, any determination made by the CMA on appeal against a price control decision must be regarded as final on the points appealed. Ofgem does not have the power to

[212] British Gas Trading v GEMA [2015] para 3.52 and Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc v the Gas and Electricity Markets Authority [2015] para 3.51

overturn elements of a final determination by the CMA or to undo elements of the CMA's determination with which it disagrees.

15.15 Ofgem has some discretion in terms of how it implements an order made by the CMA (in terms of Section 11H(3) of the EA89, Ofgem is under a duty to "*take such steps as it considers requisite for it to comply with*" the CMA's order). However, in making a decision about the appropriate means of implementation Ofgem is under a general public law duty to act reasonably and not to frustrate the underlying purpose of the CMA's determination.

15.16 If a party to an appeal is dissatisfied with the CMA's determination, their remedy is judicial review. Hence, other than in the very limited circumstances discussed below, where the CMA either quashes Ofgem's decision or substitutes its own decision, an attempt by Ofgem to carry out a post appeals review and to adjust elements of the price control that are linked to aspects of its decision that are overturned on appeal to the CMA would be contrary to the finality of the CMA's final determination.

15.17 A post-appeal licence modification in such circumstances would be *ultra vires*, leading to a further appeal to the CMA, or providing the basis for a judicial review application. It is clear that the statutory and procedural framework supporting the price controls appeals process was not intended to allow for what could prove to be an endless chain of decisions and appeals and the considerable regulatory uncertainty that would result.

<u>Revisiting wider aspects of RIIO-2</u>

15.18 SPT acknowledges that, in certain very limited scenarios (as envisaged by Ofgem at paragraph 11.32 of the Draft Determination), it is possible that the CMA may remit to Ofgem the price control matter on terms which require Ofgem to consider interlinkages to some degree. Nevertheless, in such circumstances, Ofgem would only have the power to revise its licence modifications to the extent that this is required by the terms of any order for remission and directions made by the CMA.

15.19 Further, it is clear that the current regime already allows the CMA to consider interlinkages, as confirmed by the CMA in its open letter to Ofgem dated 30 October 2019 (the **CMA Open Letter**).

15.20 As detailed in paragraph 14 of the CMA Open Letter, to the extent that interlinkages form part of the response to an appeal, in stating that an error on one part of the price control is linked to another part of the price control, the CMA encourages regulators to explain these interlinkages in their decision documentation. Where such interlinkages are clearly described by the regulator, the CMA also encourages appellants (in paragraph 15 of the CMA Open Letter) to explain why the component under challenge is wrong having regard to the interlinked aspects of the decision.

15.21 The CMA also confirms in the CMA Open Letter (paragraph 16) that appellants cannot "cherry pick" just one specific unfavourable component of a regulatory assessment, assumption and decision where that is not in practice a separable decision, and can only be considered alongside other linked decision. It is also noted that "*the overall price control set by a regulator is the combination of a number of individual decisions, and we do not accept that it can be beyond the CMA's powers to review these individual decisions, on the basis that they need to be considered "in the round" with decisions that are otherwise unconnected parts of the regulatory settlement*".

15.22 This approach is reiterated by the CMA in its recent final decision on the NATS (En Route) Plc Regulatory Appeal, dated 23 July 2020. The CMA confirms in paragraph 23 of its summary of its final decision that the CMA considers "*the price control 'in the round', including any interlinkages between the different elements, to ensure [its] decisions are balanced and provided consistent incentives while not making it unduly difficult for NERL to finance its activities, taking into account the CAA review and reconciliation which will be taking place in 2021*".

15.23 In light of this, to the extent that interlinkages are already taken into account by the CMA in any final determination, it would be wrong for Ofgem to consider such linkages again.

Summary

15.24 SPT does not support Ofgem's proposal to include a statement of policy in Final Determinations that Ofgem will carry out a post appeals review. Furthermore, SPT does not support Ofgem's proposal to potentially revisit wider aspects of RIIO-2 in the event of a successful appeal to the CMA.

15.25 The existing statutory framework already allows for the CMA to consider interlinkages as part of any appeal and to remit to Ofgem the price control matter on terms which would permit Ofgem to consider interlinkages if and as required.

15.26 Ofgem does not have the power to overturn elements of a final determination by the CMA or to undo elements of the CMA's determination with which it disagrees. Any wider attempt by Ofgem to carry out a post appeals review and to adjust elements of the price control that are linked to aspects of its decision that are overturned on appeal to the CMA would be contrary to the finality of the CMA's final determination, *ultra vires* and unlawful.

Q42. Do you have any views on the proposed pre-action correspondence, including on the proposed timing for sending such to Ofgem?

15.27 SPT agrees that some degree of pre-action correspondence may be beneficial for all parties. However, SPT does not agree with the scope of pre-action correspondence currently proposed by Ofgem in the Draft Determination (paragraph 11.36), in which it is stated that Ofgem expects potential appellants to come forward "t*o clearly explain their intention to appeal, the element(s) of the RIIO-2 price control that they intend to appeal, the scope of that appeal including, in sufficient detail, the alleged errors, and why that particular component(s) of the price control is wrong having regard to interlinked aspects of the decision*".

15.28 As Ofgem is aware, the CMA has itself confirmed in the CMA Open Letter (paragraph 12) that in terms of pre-appeal conduct it agrees that "active engagement is beneficial for all parties". However, the CMA explains in the CMA Open Letter that it would 'ideally' prefer the pre-notification of an appeal to include the potential scope of any appeal, rather than be limited to notification of the potential existence of an appeal. Ofgem's requirements in relation to pre-action correspondence as set out in the Draft Determination go well beyond the CMA's stated expectations in the CMA Open Letter.

15.29 Ofgem's requirements as set out in the Draft Determination are also at odds with the conventional reason for encouraging pre-action correspondence in litigation, which is to encourage parties to resolve their differences without going to court. It is difficult to envisage, post Final Determination, how pre-action correspondence would at this stage enable or encourage Ofgem or a potential appellant to resolve their differences relating to the price control without going to the CMA.

15.30 SPT has and will continue to engage extensively with Ofgem throughout the price control process and Ofgem will be aware of SPT's position on key issues. It follows that the scope of Ofgem's proposals for pre-action correspondence is not only contrary to established norms in litigation, but also introduces unnecessary activity into the process.

Summary

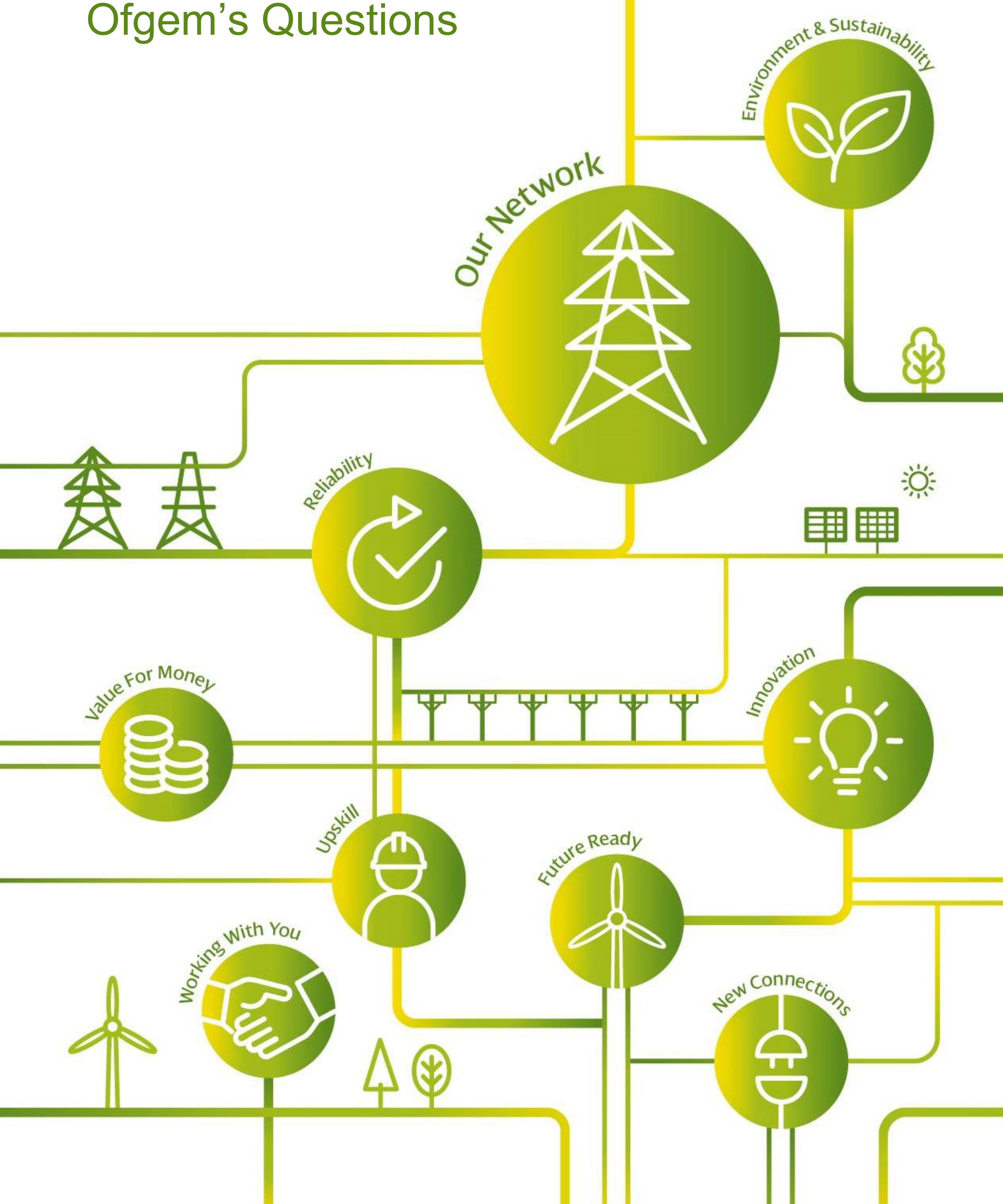
15.31 Although SPT is willing to engage in pre-action correspondence, SPT does not agree with the scope of pre-action correspondence currently proposed by Ofgem.

15.32 Any pre-action correspondence should be limited to include a high-level overview of the potential scope of any appeal, allowing the parties to allocate appropriate resources ahead of any application for permission being made to the CMA.

15.33 In any event, the two-month window following a final price control determination envisaged by Ofgem in the Draft Determination would not provide sufficient time to prepare pre-action correspondence in the level of detail proposed by Ofgem.

SP Energy Networks
4th September 2020

Annex 1: Mapping to Ofgem’s Questions



Questions Core Document	Mapping to Chapter	Mapping to Page Number	Mapping Link Paragraph Reference
Q1. What role should Groups play during the price control period and what type of output should Groups be asked to deliver? Who should be the recipients of these outputs (companies, Ofgem and/or stakeholders)?	Stakeholder Engagement	168	10.12 to 10.16
Q2. What role should Groups take with respect to scrutinising new investment proposals which are developed through the uncertainty mechanisms?	Stakeholder Engagement	168	10.17
Q3. What value would there be in asking Groups to publish a customer-centric annual report, reviewing the performance of the company on their business plan commitments?	Stakeholder Engagement	169	10.18 to 10.20
Q4. What value would there be in providing for continuity of Groups (albeit with refresh to membership as necessary) in light of Ofgem commencing preparations for RIIO-3 by 2023?	Stakeholder Engagement	169	10.21
Q5. Will the combination of the two proposed Licence Obligations support the delivery of a digitalised energy system and maximise the value of data to consumers?	Digitalisation	189	14.2 to 14.4
Q6. Do you agree with our proposed frequency for publication of updates to the digitalisation strategy and the digitalisation action plan, respectively?	Digitalisation	189	14.5
Q7. What kinds of data do you think should comply with the data best practice guidance to maximise benefits to consumers through better use of data?	Digitalisation	189	14.6
Q8. Do you agree that the Groups could have an enduring role to work with the companies to monitor progress and ensure they deliver the commitments in their engagement strategies?	Stakeholder Engagement	169	10.22 to 10.23
Q9. Do you agree with our proposal to accept the proposals for an ODI-R for BCF and the other proposals set out above as EAP commitments and to require progress on them to be reported as part of the AER?	Environment and Sustainability	173	11.15 to 11.16
Q10. Do you agree with our proposed RPEs allowances? Please specifically consider our proposed cost structures, assessment of materiality, and choice of indices in your answer.	RPEs and Ongoing Efficiency	89	4.13 to 4.33
Q11. Do you agree with our proposed ongoing efficiency challenge and its scope?	RPEs and Ongoing Efficiency	92	4.1 to 4.27
Q12. Do you agree with our proposed common approach for re-openers?	Uncertainty Mechanism	105	5.47 to 5.53

Q13. Do you agree with our proposals on a materiality threshold, a financial incentive, a 'foreseeable' criterion, and who should trigger and make the application?	Uncertainty Mechanism	106	5.54
Q14. Do you consider that two application windows, or annual application windows, are more appropriate, and should these be in January or May?	Uncertainty Mechanism	106	5.55 to 5.56
Q15. Do you consider that the RIIO-1 electricity distribution licences should be amended to include the CAM, or wait until in 2023 at the start of their next price control?	Uncertainty Mechanism	106	5.57 to 5.58
Q16. Do you agree with our proposed re-opener windows for cyber resilience OT and IT, and our proposal to require all licensees to provide an updated Cyber Resilience OT and IT Plan at the beginning of RIIO-2?	Uncertainty Mechanism	107	5.59 to 5.60
NEW Q17 - What are your views on including the delivery of outputs such as: CAF outcome improvement; risk reduction; and cyber maturity improvement, along with projects-specific outputs??	Uncertainty Mechanism	107	5.61 to 5.62
Q18. Do you agree with our proposal for the Non-operational IT and Telecoms capex re-opener?	Uncertainty Mechanism	107	5.63 to 5.65
Q19. Do you agree with our approach to using a re-opener mechanism for changes to government physical security policy?	Uncertainty Mechanism	108	5.66
Q20. Do you agree with our approach regarding legislation, policy and standards?	Uncertainty Mechanism	108	5.67 to 5.91
Q21. Do you agree with our overall approach to meeting Net Zero at lowest cost to consumers? Specifically, do you agree with our approach to fund known and justified Net Zero investment needs in the baseline, and to use uncertainty mechanisms to provide funding in-period for Net Zero investment when the need becomes clearer?	Uncertainty Mechanism	112	5.92 to 5.96
Q22. Do you think the package of cross sector and sector-specific UMs provides the appropriate balance to ensure there is sufficient flexibility and coverage to facilitate the potential need for additional Net Zero funding during RIIO-2?	Uncertainty Mechanism	113	5.97 to 5.98
Q23. Do you have any views on our proposed approach to a Net Zero re-opener?	Uncertainty Mechanism	113	5.99
Q24. Do you agree with our proposals for the RIIO-2 Strategic Innovation Fund?	Innovation	179	12.5 to 12.7
Q25. Do you have any comments on the additional issues that we seek to consider over the coming year ahead of introducing the Strategic Innovation Fund?	Innovation	179	12.8 to 12.10
Q26. Do you agree with our approach to benchmarking RIIO-2 NIA requests against RIIO-1 NIA funding?	Innovation	179	12.11 to 12.16

Q27. Do you agree with our proposal that all companies' NIA funding should be conditional on the introduction of an improved reporting framework?	Innovation	180	12.17
Q28. What are your thoughts on our proposals to strengthen the RIIO-2 NIA framework?	Innovation	180	12.18 to 12.22
Q29. Do you have any additional suggestions for quality assurance measures that could be introduced to ensure the robustness of RIIO-2 NIA projects?	Innovation	181	12.23
Q30. Do you agree with our proposals to allow network companies and the ESO to carry over any unspent NIA funds from the final year of RIIO-1 into the first year of RIIO-2?	Innovation	181	12.24
Q31. Do you agree with our proposal that all work relating to data as part of innovation projects funded via the NIA and SIF will be expected to follow Data Best Practice?	Innovation	181	12.25
Q32. Do you agree with our proposed position on late competition?	Competition	159	9.7 to 9.34
Q33. Do you agree with our proposed approach on early competition?	Competition	162	9.35 to 9.53
Q34. Do you agree with our view that SHET, SPT, SGN and WWU passed all of the Minimum Requirements, and as such are considered to have passed Stage 1 of the BPI?	Business Plan Incentive and Sharing Factor	121	6.17
Q35. Do you agree with our rationale for why NGET and NGGT should be considered to have failed Stage 1 of the BPI?	Business Plan Incentive and Sharing Factor	121	6.18
Q36. Do you agree with our rationale for why Cadent and NGN are considered to have passed Stage 1 of the BPI?	Business Plan Incentive and Sharing Factor	121	6.19
Q37. Do you agree with our overall approach regarding treatment of CVP proposals?	Business Plan Incentive and Sharing Factor	121	6.20 to 6.22
Q38. Do you agree with our proposed clawback mechanism to treat received CVP rewards?	Business Plan Incentive and Sharing Factor	121	6.23
Q39. Do you have any views on the interlinkages explained throughout this chapter?	Interlinkages and CMA	190	15.2 to 15.3
Q40. Are there other interlinkages within our RIIO-2 package that you think are relevant to the three pillars identified in this chapter?	Interlinkages and CMA	190	15.4 to 15.8

Q41. Do you have any views on our proposal to include a statement of policy in Final Determinations that in appropriate circumstances, we will carry out a post appeals review and potentially revisit wider aspects of RIIO-2 in the event of a successful appeal to the CMA that had material knock on consequences for the price control settlement?	Interlinkages and CMA	191	15.9 to 15.26
Q42. Do you have any views on the proposed pre-action correspondence, including on the proposed timing for sending such to Ofgem?	Interlinkages and CMA	193	15.27 to 15.33
Q43. Do you think we need specific mechanisms in RIIO-2 to manage the potential longer-term impacts of COVID-19? If yes, what might these mechanisms be?	Impact of COVID-19	185	13.2 to 13.19
Electricity Transmission Annex	***Mapping to Chapter***	**Mapping to Page Number**	**Mapping Link Paragraph Reference**
ETQ1. Do you agree with our proposals to switch off the incentive in year one of RIIO-ET2 in order to pilot the Quality of Connections survey and develop the baseline targets?	Incentives	130	7.25 to 7.58
ETQ2. Do you have views on the common milestones, target audience and question of overall satisfaction for the Quality of Connections survey incentive provided in Appendix 2?	Incentives	134	7.59 to 7.60
ETQ3. Do you think there are any additional KPIs that have not been included in the final NAP which would support monitoring of performance in adherence to the NAP and/or add transparency of the outage planning, management and implementation process for relevant stakeholders?	Incentives	134	7.61 to 7.63
ETQ4. Do you agree with our proposed LPD mechanisms and do you agree with the criterion that we are proposing to use for our LPD mechanisms?	Incentives	135	7.64 to 7.68
ETQ5. What are your views on applying our LPD mechanisms to some or all of the projects identified at paragraph 2.74?	Incentives	135	7.69
ETQ6. What are your views on our consultation position for the three electricity TOs' EAP proposals in RIIO-2 as set out in this document?	Environment and Sustainability	173	11.17 to 11.47
ETQ7. What are your views on our consultation position for setting the expenditure cap for visual amenity mitigation projects in RIIO-2?	Environment and Sustainability	177	11.48
ETQ8. Do you have any views on our outputs that have not been covered through any of the specific consultation questions set out elsewhere in this	Expenditure and Outputs	136	

chapter? If so, please set them out, making clear which output you are referring to.			7.70 to 7.129
ETQ9. Do you have any views on our overall approach to setting totex allowances?	Expenditure and Outputs	26	2.40
ETQ10. Do you agree with our proposed eligibility criteria for the LOTI re-opener and do you agree with the assessment stages, and their associated timings?	Uncertainty Mechanism	113	5.100 to 5.104
ETQ11. Do you agree with our proposed definition of PCF for RIIO-2, and the areas of work that we intend that definition to cover?	Uncertainty Mechanism	114	5.105 to 5.108
ETQ12. Do you agree with our proposal to assess PCF costs as part of RIIO-2 Closeout, following the principles set out in Chapter 4?	Uncertainty Mechanism	115	5.109 to 5.113
ETQ13. Do you agree with our proposed scope of, associated eligibility criteria for, and timing of the submission window under the MSIP re-opener?	Uncertainty Mechanism	116	5.114 to 5.125
Finance Questions	**Mapping to Chapter**	**Mapping to Page Number**	**Mapping Link Paragraph Reference**
FQ1. Do you agree with our approach to estimating efficient debt costs and setting allowances for debt costs?	Finance	58	3.77 to 3.93
FQ2. Do you agree with our proposal to use the iBoxx GBP Utilities 10yr+ index rather than a combination of iBoxx GBP A and BBB 10yr + non-financial indices?	Finance	61	3.94 to 3.96
FQ3. Do you agree with our proposal that the RAV growth profile of SHET continues to be materially different to other networks and therefore warrants continuation of a bespoke RAV weighted allowance calculation?	Finance	61	3.97
FQ4. Do you have any views on the model to implement equity indexation, as published alongside this document, (the “WACC allowance model.xlsx”) or on the annual update process?	Finance	61	3.98 to 3.110
FQ5. In light of RIIO-2 Draft Determinations and Ofwat’s final determinations for PR19, do you believe that energy networks will hold similar systematic risk during RIIO-2 to water networks during PR19?	Finance	63	3.111 to 3.125

FQ6. Is there evidence of a material difference in systematic risk between: a) RIIO-1 and RIIO-2, b) distribution and transmission networks, c) gas transmission and electricity transmission d) gas and electricity?	Finance	68	3.126 to 3.130
FQ7. Do you have any views on how we should consider further the gearing impact on beta and cost of capital estimates?	Finance	70	3.131 to 3.137
FQ8. Do you agree with our interpretation of cross-checks?	Finance	71	3.138 to 3.169
FQ9. What is your view on the overall in-the-round assessment of allowed returns to equity? Is our judgement of 3.95% at 60% notional gearing reflective of the combined analysis through Steps 1, 2, and 3?	Finance	75	3.170 to 3.171
FQ10. What is your view on the expected outperformance estimate of 0.25% at 60% notional gearing? Do you recommend alternative analysis techniques or do you have suggested improvements to the analytical files published alongside this consultation? a) “AR-ER database.xlsx” b) "Residual outperformance.xlsx" c) "Simple MAR application model.xlsx"	Finance	76	3.172 to 3.180
FQ11. What is your view on an ex-post adjustment for baseline equity returns? Is there an alternative mechanism or implementation approach that you think could better meet our stated objectives? Do you have specific views on averaging, pooling or suggested simplifications?	Finance	77	3.181 to 3.182
FQ12. Do you agree with our approach to assessing financeability?	Finance	78	3.183 to 3.202
FQ13. Do you agree with our approach to determining notional gearing for each notional company?	Finance	80	3.203 to 3.204
FQ14. Do you have any evidence that would suggest we should consider adjusting our notional company financing assumptions due to the impact of COVID-19?	Finance	80	3.205 to 3.206
FQ15. Do you agree with our proposal to pursue Option A?	Finance	81	3.207
FQ16. Do you agree with our proposals to roll forward capital allowance balances and to make allocation and allowance rates Variable Values in the RIIO-2 PCFM?	Finance	81	3.208

FQ17. Do you agree with the proposed additional protections? In particular: a) do you have any views on a materiality threshold for the tax reconciliation? Do you think that the "deadband" used in RIIO-1 is an appropriate threshold to use? b) Do you have any views on our proposals to retain the Tax Trigger and Tax Clawback mechanisms from RIIO-1? c) Do you have any views on the proposed process for the Tax Review? d) Do you have any views on the proposed board assurance statement?	Finance	81	3.209 to 3.212
FQ18. Do you agree with our proposal to introduce a symmetrical RAMs mechanism as described above?	Finance	81	3.213 to 3.215
FQ19. Do you agree with our proposal to introduce a single threshold level of 300 basis points either side of the baseline allowed return on equity?	Finance	82	3.216
FQ20. Do you have any other comments on our proposals for RAMs in RIIO-2?	Finance	82	3.217
FQ21. Do you agree with our proposal to implement CPIH inflation?	Finance	82	3.218
FQ22. Do you agree with our proposals, including the policy alignment for GT and GD, and to recover backlog depreciation for GT RAV additions (2002 to 2021) over 20 years from the start of RIIO-2?	Finance	82	3.219
FQ23. Do you agree with our proposed assumptions for capitalisation rates?	Finance	82	3.220 to 3.223
FQ24. For one or more of the aggregations of totex we display in Table 40, should we update rates ex-post to reflect reported outturn proportions for capex and opex?	Finance	83	3.224
FQ25. Do you agree with our proposal to use the closing RIIO-1 RAV balances as opening balances for RIIO-2?	Finance	83	3.225 to 3.226
FQ26. Do you agree with our proposal to use estimated opening RIIO-2 balances until we have finalised the closing RIIO-1 RAV balances?	Finance	83	3.227
FQ27. Do you agree with the three categories of adjustments outlined below?	Finance	83	3.228 to 3.229
FQ28. Do you agree with our approach in using estimated values for closeout adjustments until we are able to close out the RIIO-1 price controls?	Finance	83	3.230
FQ29. Do you agree that proceeds from the disposal of assets during RIIO-2 should be netted-off against totex from the year in which the proceeds occur?	Finance	84	3.231
FQ30. Do you agree that we should carry out a review where an asset is transferred to a holding company and		84	

then subsequently sold to a third party?	Finance		3.232
FQ31. Do you agree with our proposal to apply one interest rate to revisions to PCFM inputs and charging errors, based on a short-term cost of debt?	Finance	84	3.233 to 3.237
FQ32. Do you agree with the margin-based approach, and the methodology used to calculate a margin of 110bps?	Finance	84	3.238
FQ33. Do you have any reason why the marginal cost of capital for revisions to PCFM inputs and charging errors should remain distinct from each other, or why WACC may remain a more appropriate time value of money for a particular subset of prior year adjustmens?	Finance	85	3.239 to 3.243
FQ34. Do you agree with our proposal to include forecasts for most PCFM variable values for the purposes of the AIP?	Finance	85	3.244
FQ35. Considering re-openers as set out in these Draft Determinations, do you agree with our proposal to exclude them from any forecasting? If not, please submit specific examples or analysis of the potential materiality of actual spend versus initial allowances.	Finance	85	3.245 to 3.247
FQ36. Do you agree that additional reporting on executive pay/remuneration and dividend policies will help to improve the legitimacy and transparency of a company's performance under the price control?	Finance	86	3.248 to 3.250
FQ37. Do you agree with the proposed definition of Base Revenue?	Finance	86	3.251
FQ38. Do you agree with the proposal to fix the values used for ODI caps and collars at final determinations?	Finance	86	3.252
SPT Annex	**Mapping to Chapter**	**Mapping to Page Number**	**Mapping Link Paragraph Reference**
SPTQ1. Do you agree with our proposals on the bespoke ODIs? If you disagree, please outline why.	Incentives	143	7.130 to 7.153
SPTQ2. Do you agree that SPT's bespoke ODI-R would be in the interests of existing and future consumers and do you have any views on the proposed metrics to track SPT's progress in delivering the ODI-R?	Incentives	147	7.154 to 7.155
SPTQ3. Do you agree with our proposal to reject SPT's bespoke ODI-F at this time?	Incentives	147	7.156 to 7.162
SPTQ4. Do you agree that SPT's bespoke ODI-F should be rejected?	Incentives	148	7.163 to 7.170

SPTQ5. Do you agree with our consultation position to reject the "RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs"?	Incentives	149	7.171 to 7.187
SPTQ6. Do you agree with our proposals on the PCDs? If not, please outline why.	Expenditure and Outputs	26	2.41 to 2.46
SPTQ7. Do you agree that SPT's bespoke Net Zero Fund should be included in RIIO-ET2?	Expenditure and Outputs	27	2.47
SPTQ8. Do you have any views on the conditions we are proposing applying to SPT's bespoke output?	Expenditure and Outputs	27	2.48
SPTQ9. Do you agree with our proposals on the CVPs? If not, please outline why.	Business Plan Incentive and Sharing Factor	122	6.24 to 6.29
SPTQ10. Do you agree with our consultation position to accept the maximise benefit from non-operational land CVP?	Business Plan Incentive and Sharing Factor	124	6.30 to 6.34
SPTQ11. Do you agree with our proposed allowances in relation to load related capex? If not, please outline why.	Expenditure and Outputs	27	2.49 to 2.60
SPTQ12. Do you agree with our proposed allowances in relation to non-load related capex? If not, please outline why.	Expenditure and Outputs	30	2.61 to 2.73
SPTQ13. Do you agree with our proposed allowances in relation to non-operational capex? If not, please outline why.	Expenditure and Outputs	34	2.74 to 2.79
SPTQ14. Do you agree with our proposed allowances in relation to network operating costs? If not, please outline why.	Expenditure and Outputs	35	2.80 to 2.97
SPTQ15. Do you agree with our proposed allowances in relation to indirect operational expenditure? If not, please outline why.	Expenditure and Outputs	38	2.98 to 2.121
SPTQ16. Do you have any other comments on our proposed allowances for SPT?	Expenditure and Outputs	44	2.122
SPTQ17. Do you agree with our proposals for a re-opener covering these six non-load related projects?	Uncertainty Mechanism	117	5.126
SPTQ18. Do you agree with the level of proposed NIA funding for SPT? If not, please outline why.	Innovation	181	12.26 to 12.38
NARM	**Mapping to Chapter**	**Mapping to Page Number**	**Mapping Link Paragraph Reference**
NARMQ1. Do you agree with our proposals on the scope of work within each of the NARM Funding Categories and on the associated funding arrangements?	NARM	155	8.15 to 8.17

NARMQ2. Do you agree the funding adjustment principles and our proposals for applying funding adjustments?	NARM	155	8.18 to 8.22
NARMQ3. Do you agree with our proposed approaches to calculating funding adjustments and to application of penalties?	NARM	156	8.23 to 8.32
NARMQ4. Do you agree with our proposals in regards to requirements for justification cases?	NARM	157	8.33