SSEN DISTRIBUTION RIIO-ED2

UNCERTAINTY MECHANISMS

RIIO-ED2 Business Plan Annex 17.1

Scottish & Southern Electricity Networks

CONTENTS

EXECUTIVE SUMMARY

As a nation we are committed to realising a net zero future. Governments have set legally binding commitments to ensure we achieve that ambition. While the destination is assured, the pathway and pace towards remain uncertain. As a company we are committed to delivering greatest value for consumers and only committing to expenditure when the needs case is clear. For our RIIO-ED2 business plan this means in some specific areas we are awaiting new/ updated information to be revealed which could change our baseline investment proposals. Uncertainty mechanisms respond to these challenges to provide our customers with a continued high quality, high value network service.

Uncertainty Mechanisms (UMs) for RIIO-ED2 (RIIO-ED2) are the primary method for ensuring the price control has significant flexibility to meet the known unknown challenges in ED2. We are very clear however UMs are not a catch-all or an insurance policy. They should not shift risk from the DNO to consumers and equally should not act as a disincentive to finding efficiencies through delivery. Each of our proposals has been pressure tested carefully to ensure genuine need.

It is through the engagement with our stakeholders that we have proposed nine UMs in addition to those presented by Ofgem in its Sector-Specific Methodology Decision (SSMD)[1]. In this annex we clearly show the process we have been through and how we arrived at our proposals. Our summary proposals are outlined in the 'Summary Table' below.

Throughout this Annex, we refer collectively to our nine proposed UMs that we have designed as 'additional UMs'. We have developed our additional UM proposals using a robust methodology, which features an iterative design process with stakeholder co-creation at its heart. Moreover, our additional UM proposals have been developed in line with Ofgem's Business Plan Guidance[2], ensuring that each provides clear value to consumers.

Summary Table: Our-proposed and Ofgem-confirmed UMs

[1] Sector-Specific Methodology Decision, ch.8

[2] Business Plan Guidance, pp. 48-49

UM name	Type of UM	Applicable to	Issues addressed	Cost uncertainty range relative to our RIIO-ED2 baseline
Our proposed UMs (Detailed in section 6)				
Wayleaves and Diversions	Re-opener & close out mechanism	All DNOs[3]	Costs associated with uncertain diversions costs following wayleave terminations.	SEPD[4] -£9m to +£35m SHEPD -£1m to +£1m
Shetland	Re-openers & pass through	SHEPD only	Costs associated with extended full duty supply arrangements pre-link, and providing an enduring supply to Shetland, including, backup supply electricity post construction of the new transmission link to the UK mainland.	SEPD N/A SHEPD[5] -£13m to +14m
Subsea Cables	Volume driver & Re-openers	SEPD and SHEPD	Costs associated with subsea cable replacement following damage or faults, additional remote backup generation and cable decommissioning.	SEPD Not quantified SHEPD £0 to +£76m
Hebrides & Orkney Whole Systems	Re-opener	SHEPD only	Costs associated with the outcomes of additional whole system analysis in the Scottish Islands to meet net zero to be undertaken in RIIO-ED2	SEPD N/A SHEPD -£151m to £275m
OpEx adjustor	Volume driver	All DNOs	Costs associated with adjusting the efficient level of operating expenditure SSEN requires to deliver specific uncertainty mechanisms.	SEPD -£9m to £96m SHEPD -£3m to £35m
Distributed Generation Monitoring	Re-opener	All DNOs	Costs related to the possibility of increased DG monitoring requirements resulting from Ofgem's review of the issue.	SEPD £0 to +£24m SHEPD £0 to +£17m
Polychlorinated Biphenyls	Volume driver	All DNOs	Costs related to removing assets containing PCBs from our network to meet legislative requirements.	SEPD £0 to +£16m SHEPD £0 to +£20m
Ash dieback removal	Re-opener	All DNOs	Costs associated with removing Ash dieback diseased trees in proximity of contact with our network.	SEPD £0 to +£38m SHEPD £0 to +£10m

[3] Distribution Network Operators

[4] Southern Electric Power Distribution

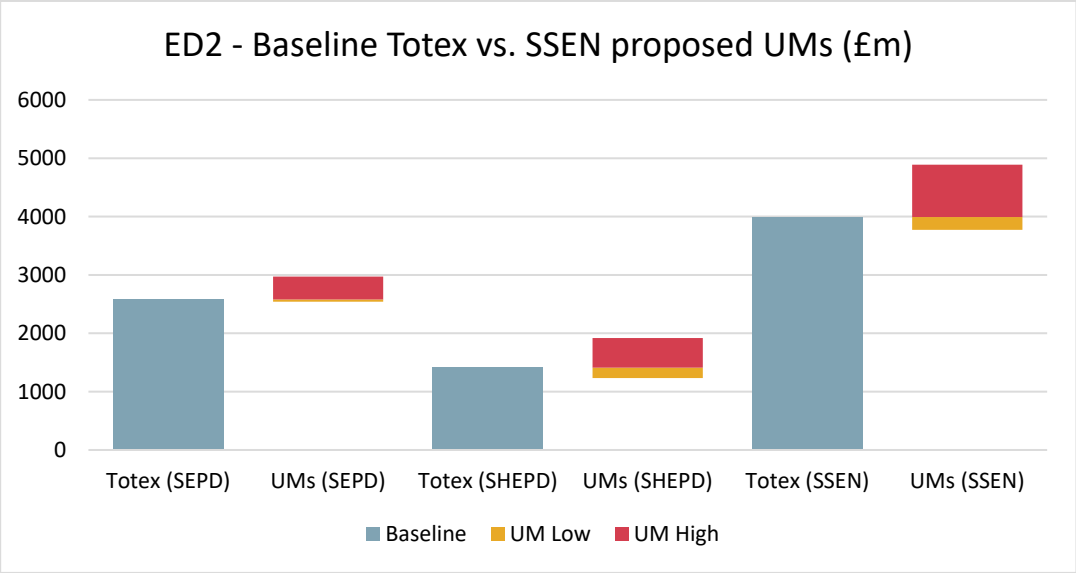
[5] Scottish Hydro Electric Power Distribution

UM name	Type of UM	Applicable to	Issues addressed	Cost uncertainty range relative to our RIIO-ED2 baseline
Strategic Investment	Volume driver	All DNOs	Costs related to uncertain load-related expenditure driven by the net zero transition and rising demand for electricity. We detail our approach to this in more detail in appendix 28_A.	SEPD -£21m to +£182m SHEPD -£9m to +£58m
Ofgem-confirmed UMs (Detailed in section 7)				
Smart Meter Interventions	Volume Driver	All DNOs	Costs of callouts related to smart meter installations.	SEPD £0 SHEPD £0
Cyber Resilience	Re-opener	Cross-sector	Costs caused by new cyber risks or regulations.	SEPD -£[redacted] to +£[redacted]m SHEPD -£[redacted]m to +£[redacted]m
Electricity System Restoration (Black Start)	Re-opener	All DNOs	Costs due to changes in government Black Start regulations.	SEPD £0 to +£14m SHEPD £0 to +£7m
Environmental Legislation	Re-opener	All DNOs	Costs of changes to DNO Environmental Action Plans due to new legislation or regulations.	SEPD £0 to +£84m SHEPD £0 to +£34m
Street Works	Re-opener	All DNOs	Uncertainty around costs related to performing works on public streets.	Unquantifiable
Rail Electrification	Re-opener	All DNOs	Costs borne by DNOs due to rail electrification programmes.	Unquantifiable
Net Zero	Re-opener	Cross-sector	Costs due to new legislation relating to net zero.	Unquantifiable
Coordinated Adjustment Mechanism	Re-opener	Cross-sector	Enabling transfer of costs/outputs between network companies.	Unquantifiable
Enhanced Physical Site Security	Re-opener	Cross-sector	Changes in the scope of physical site security work mandated by the government.	SEPD -£[redacted] to +£[redacted]m SHEPD -£[redacted]m to +£[redacted]m
Note: there are several Ofgem-proposed finance-related UMs that are dealt separately in the Finance chapter of our business plan ***(Finance and Financeability (Chapter 19)***)				

An uncertainty currently affecting much of the UK and global economy is the impact of the COVID-19 pandemic. Our experience to date has shown that, despite creating challenges, we've still been able to largely enact our RIIO-ED1 settlement in the context of the COVID-19 pandemic. As such, although we did consider mechanisms to cope with 'Health pandemic costs', we have not included this in our proposals for RIIO-ED2. More detail on this area, as well as other uncertainty areas we deprioritised, can be found in Appendix C.

We have also carefully considered the overall impact of our proposals. These are well summarised in the Summary Figure below, which characterises the uncertainty in the round.

Summary Figure: Aggregate cost uncertainty ranges for SEPD, SHEPD and SSEN (£m)



The Summary Figure shows that whilst there is potential for both downward and upward cost impacts from UMs, our aggregate cost uncertainty ranges are asymmetrically tilted towards upward cost impacts (relative to our baseline TotEx), with a downward sensitivity at -**5.5%** of TotEx and an upward sensitivity at **+22.5%** of TotEx. Our two licence areas have a different exposure to cost impacts as a proportion of TotEx but our SHEPD licence area has the larger impact due to the Subsea Cables and Hebrides and Orkney UMs.

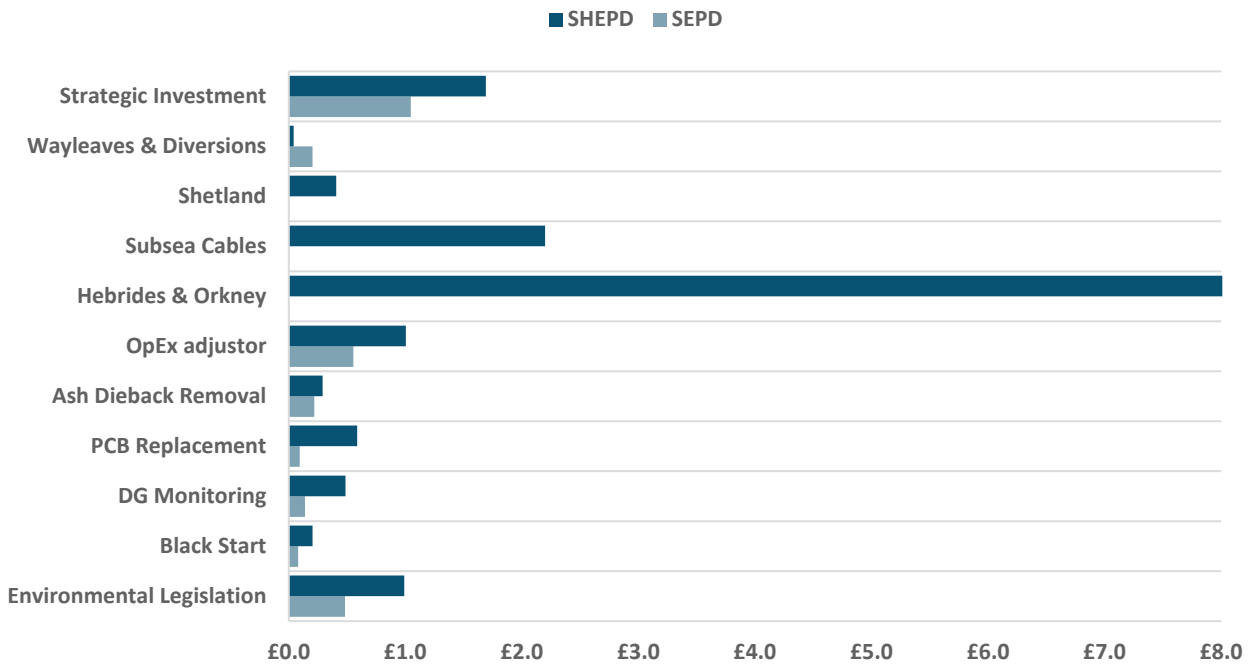
The asymmetric distribution of cost impacts reflects how we have developed an efficient investment programme for RIIO-ED2, which includes costs in baseline allowances only where it is highly likely or certain that investment is needed. Our proposed UMs provide the flexibility for additional investment should this be required to meet customers' needs, whilst also enabling material downward allowance adjustments (thereby reimbursing customers) should outturn costs end up lower than forecast. Whilst it is informative to show the combined cost impacts of our UMs, it is highly unlikely that the maximum upward cost impact will be simultaneously realised across all UMs included in the Summary Figure, and the true cost impact is likely to fall within the ranges shown.

Translating the maximum additional allowance requirements into a bill impact result in £2.80 being added to the average annual RIIO-ED2 domestic bill for SEPD and £16.10 for SHEPD. The impacts of individual UMs are summarised in the Bill impact Summary Figure. Again, we note it is highly unlikely that the maximum upward cost impact will be simultaneously realised across all UMs and the bill impact from UMs will likely be lower than the maximum quoted.

We note specifically that the bill impact for SHEPD is considerably larger for SHEPD compared to SEPD. Firstly this is reflective of the much lower number of customers in the region but more significantly, as illustrated in the Bill Impact Summary Figure, it is significantly influenced by the Hebrides and Orkney UM. Without this UM the average annual RIIO-ED2 domestic bill for SHEPD would be £8.10. As we stress in our justification for this UM, see section 6, the purpose of this UM is to allow us to work with third party

stakeholders to undertake a whole system assessment to find the optimal solution which maximises socio-economic welfare in the region whilst delivering on a broad range of stakeholder needs. It is entirely possible a lower cost SHEPD contribution to this optimal solution could be found and the remaining costs distributed over a wider, or different customer, base which lowers bill impact for SHEPD customers. Until we undertake this whole system assessment, we are required to use a proxy for distribution impacts, as outlined in section 6, which results in the average annual RIIO-ED2 domestic bill impact of £8.0 for SHEPD consumers in RIIO-ED2.

Bill Impact Summary Figure: Indicative bill impact from Uncertainty Mechanisms



Changes to our UM proposals between draft and final business plan submissions

Since submitting our draft RIIO-ED2 business plan in July 2021 we have re-engaged with our stakeholders and carefully reviewed the feedback received, including from our Customer Engagement Group (CEG) and Ofgem's Challenge Group. This feedback has been immensely helpful in pressure testing our proposals for UMs and re-calibrating our balance of funding in specific areas between the baseline and the UM.

In summary our changes include removing our draft plan proposals for a:

- LV monitoring UM
- Access SCR UM
- Radio Spectrum UM

… And introducing proposals for new UMs covering:

- Hebrides and Orkney Whole System
- OpEx Adjustor

We also have re-calibrated our balance of funding between the UM and baseline in 6 areas following pressure testing of our draft plan:

- Load related expenditure (Strategic Investment) – see appendix 28_A
- Wayleaves & Diversions
- Polychlorinated Biphenyls
- Environmental legislation
- Shetland
- Cyber Resilience

We have also developed a more comprehensive Load related investment UM proposal. In annex 17.1.1 we summarise this proposal. Throughout this document we provide the rationale for these changes and supporting information.

1. INTRODUCTION

UMs provide flexibility to adjust specific allowances during RIIO-ED2, when this is needed due to factors unknown to the DNO at the time of submitting the baseline business plan and outside our control. This can be both an increase and a decrease to allowances.

In its RIIO-ED2 Sector Specific Methodology Decision (SSMD),[6] Ofgem recognises that UMs are necessary to cope with the challenges of forecasting some costs and outputs in advance, and states that they have become even more important given the significant uncertainty around the investment needed to facilitate net zero. This extends to our customers and broader stakeholders, whose demand for electricity (driven in turn by adoption of low-carbon technologies) will have a major influence on the levels of investment required over RIIO-ED2. As we outline later in this document, the increased importance of UMs has also been reflected by Ofgem's recent Final Determinations for RIIO-T2 (T2) and RIIO-GD2 (GD2).[7]

Ofgem has already outlined several UM proposals in its RIIO-ED2 SSMD document,[8] and has invited DNOs to work with it on others, including Load related expenditure (Strategic Investment), which would deal with the net zero driven uncertainty highlighted above. Given the significant nature of this UM for the RIIO-ED2 period we separately outline our proposals in ***Strategic Investment UM (Appendix 17.1.1)*** to this annex.

DNOs are invited to submit their own uncertainty mechanism proposals where they identify other areas of uncertainty. The primary purpose of this Annex is to outline our proposed additional UMs in detail, and to show how these have been shaped by our stakeholders.

There are five types of UM defined by Ofgem,[9] and these are outlined in Figure 1.1 below.

[6] RIIO-ED2 SSMD Appendix 2, p.63

[7] RIIO-2 Final Determinations for Transmission and Gas Distribution network companies and the Electricity System Operator – Core Document, ch.7

[8] RIIO-ED2 SSMD Appendix 2, pp. 65-66

[9] RIIO-ED2 SSMD Appendix 2, pp.63-64

Figure 1.1: Types of UM

RE-OPENER
To decide, within a price control period, on additional allowances to deliver an activity once there is more certainty on the needs case, project scope, or cost

VOLUME DRIVER
To adjust allowances in line with the actual volume of work delivered, where the volume of certain types of work that will be required over the price control is uncertain (but where the cost of each unit is stable)

PASS-THROUGH
To adjust allowances for costs incurred by us over which it has limited control and that Ofgem considers the full cost of which should be recoverable (such as business rates)

INDEXATION
To provide network companies and consumers protection against the risk that outturn prices are different to those that were forecasted when setting the price control

USE-IT-OR-LOSE-IT ALLOWANCE
To adjust allowances where the need for work has been identified, but the specific nature of work or costs are uncertain

Both Ofgem's proposed and our additional proposed mechanisms are typically re-openers or volume drivers. An exception to this is Ofgem's proposed finance-related UMs; we have discussed these in the ***Finance & Financeability chapter (Chapter 19).***

The remainder of this Annex is set out as follows:

- **Section 2** gives a summary of the uncertainty landscape we envision during RIIO-ED2. This explores how UMs fit into the RIIO-ED2 price control, gives context around our broader risk management framework, and looks at specific dimensions of uncertainty we face.
- **Section 3** discusses key takeaways from our RIIO-ED1 UM experience, as well as the mechanisms that were included in the RIIO-T2 and RIIO-GD2 final determinations published in December 2020.
- **Section 4** provides detail on the approach we used to develop our proposed additional RIIO-ED2 UMs, with a clear description of how each step of our approach was applied to each mechanism we propose.
- **Section 5** explains the stakeholder engagement activities we carried out on our UM proposals, discusses the insights we derived from our engagement process, and describes how we implemented resultant actions to improve our proposals and make them reflective of stakeholders' needs.

- **Section 6** provides detailed descriptions of each of our UM proposals. We provide information on each mechanism against the key criteria listed in Ofgem's Business Plan Guidance.[10]

- **Section 7** gives our views on Ofgem's decisions on RIIO-ED2 UMs to date, including default re-opener parameters, and each of Ofgem's proposed UMs.

- **Section 8** analyses our overall package of UM proposals by considering uncertainty in the round, linkages with our broader RIIO-ED2 plan, and deliverability.

We have also included three appendices to this document:

- **Appendix A** discusses the analytical techniques we used to develop technical aspects of our additional UM proposals, focussing specifically on our proposed volume drivers for Subsea Cables. The volume drivers proposed for these two UMs are more technical, and the explanations in Appendix A are designed to complement the descriptions of our UM proposals given in section 6.

- **Appendix B** discusses the data and assumptions used in the development of our mechanisms.

- **Appendix C** outlines the additional uncertainty areas we considered for UMs, but for various reasons opted to deprioritise.

- ***Strategic Investment UM (Appendix 17.1.1)*** this is a separate document which sets out our proposal for a Load Related Expenditure (Strategic Investment) volume driver uncertainty mechanism

In addition to this annex details on the cost ranges associated with our UMs can be found in Business Plan Data Table M13 and Ofgem's summary tables for outputs, UMs and CVPs.

[10] **RIIO-ED2 Business Plan Guidance**, p.48

2. THE RIIO-ED2 UNCERTAINTY LANDSCAPE

In this section, we explore how UMs fit into the RIIO-ED2 price control, and we explain how we have developed our UM proposals in the context of a broader risk and uncertainty management framework, which recognises that DNOs should face strong incentives to build their resilience and manage financial risks.

We begin this section by first exploring key causes of uncertainty at RIIO-ED2 and highlighting important trade-offs to consider when developing UMs to address these uncertainties. We then explore the role of UMs within the broader risk and uncertainty management framework, showing how these are just one of several regulatory tools for managing risk. Lastly, we consider specific dimensions of uncertainty facing us in RIIO-ED2, and we link these to the suite of RIIO-ED2 UMs proposed through Ofgem's SSMD and our business plan.

What are the key causes of uncertainty at RIIO-ED2, and how can uncertainty be managed between DNOs and consumers?

As part of the RIIO-ED2 process, we are required to submit proposed baseline allowances on an ex-ante basis. This represents our best view of the investment required to deliver our RIIO-ED2 commitments at an efficient cost. Ofgem will then scrutinise our proposals and set our allowed revenues (including allowed costs) at RIIO-ED2 final determination. We only submit baseline allowance proposals where we have relative certainty in the spend required and justified. This ensures consumers only pay for what is required at the point where the evidence supports committing to the spend.

At the core we are required to manage both **diversifiable** and **non-diversifiable** risks and uncertainties in the RIIO-ED2 period. The non-diversifiable risks are categorised as being systematic and correlated with wider economy. Consistent with the RIIO-2 framework they are managed through agreeing an efficient cost of capital for the regulatory period, specifically setting of the asset beta. In ***Finance and Financeability (Chapter 19)*** of our plan we set out our proposals for the asset beta and calibration of other parameters in the cost of capital.

Diversifiable risks and uncertainties are those specific to SSEN or the electricity distribution sector. In setting our proposals for managing these we start from the position that it is not right for SSEN to diversify all risks and uncertainties we face in RIIO-ED2.

During RIIO-ED2 all DNOs will encounter a significant range of internal and external developments, many of which will have a material impact on the investment required over RIIO-ED2. These developments incorporate a range of potential risks and uncertainties, and collectively they could result in our incurred costs deviating substantially from our proposed baseline allowances. However, it is not right that consumers should pay to manage these risks and uncertainties in advance. They are better protected using regulatory mechanisms, such as UMs, which would allow for funding to be reviewed should uncertainties materialise. This enables greater efficiency, as funding is granted only when it is needed, minimising the potential for DNOs to allocate funds where they are not needed.

Many of the challenges we face are **internal risks** which can be actively managed and mitigated internally by DNOs. These risks are generally ever-present and must be continuously managed (for example, the risk

of adverse weather in our licence areas affecting our network infrastructure). Our stakeholders (including our customers) rightly expect us to prepare for and handle the financial impacts of these risks, without the need for additional financial support from customers. Later in this section we explore the key regulatory tools which assist us in managing internal risks, and we also describe our business processes for capturing and mitigating internal risks.

However, we can also identify specific **external uncertainties** that fall outside of DNOs' direct control, which affect the need for (and extent of) DNO investment. By their nature, these uncertainties are dependent on external changes over RIIO-ED2 and will become clearer over the course of RIIO-ED2 (for example, investments related to a government policy decision due in 2025). UMs are fundamentally designed to adjust cost allowances during the RIIO-ED2 period based on external events, and therefore it is external uncertainties which are our focus when identifying and designing UMs. We caveat this however in noting that UMs should be specific and focused only on known unknowns. UMs are not a catch-all for external uncertainty. In proposing UMs a DNO must be able to clearly point to the external information that they are waiting upon being revealed and be clear that if this information was available today it is right consumers should pay for the additional costs through the baseline plan. Otherwise, the uncertainty becomes an internal risk, and it is for the company to manage.

There are several ways in which external events beyond our control could impact incurred costs over RIIO-ED2. These include (but are not limited to):

- Changes in government policy and investment decisions.
- Development of energy network infrastructure by other parties.
- Changes in demand for electricity (driven partly by consumer behaviour).
- Evolution of stakeholder preferences.

Where these events cannot be foreseen and could materially impact incurred costs, then UMs offer DNOs the opportunity to adjust their investment to better reflect services needed by customers over RIIO-ED2. This also provides DNOs with important financial flexibility, allowing them to maintain financeability should efficiently incurred costs exceed forecasts whilst delivering high-quality customer service which meets customers' growing electricity needs.

Given the need to decarbonise networks and support the net zero transition across the broader UK economy, it is particularly challenging to anticipate demand growth and forecast investment requirements for RIIO-ED2. This makes the flexibility offered by UMs particularly important. It is also important to recognise that at RIIO-ED2, our customers and broader stakeholders will play a more important role than ever in shaping the need for DNO investment, with consumer demand behaviour having a major influence. This strengthens the need to work closely with our stakeholders to develop our RIIO-ED2 Business Plan (including our UM proposals) and ensure we support the net zero transition in a sustainable, economic and efficient way. In section 5 of this document, we explain how we have tested potential UMs with stakeholders and have used their feedback to shape our proposals.

However, whilst UMs provide important support towards societal goals (which in turn benefits consumers), DNOs also have a responsibility to target their scope effectively and avoid proposing an excessive number of UMs in their business plans. Consumers value certainty and stability over their electricity bills and limiting the role of UMs helps to prevent excessive bill volatility which could otherwise harm vulnerable consumers and weaken consumer trust in the setting of price control allowances. Consumers also expect DNOs to exercise cost control and manage emerging risks, rather than viewing UMs as an insurance policy for external change. This further reinforces the importance of DNOs only seeking (and using) UMs where there is a compelling need case, including demonstrable reasons for not including the associated costs in the baseline funding plan. By doing this, Ofgem and DNOs can ensure that RIIO-ED2 UMs enable meaningful change whilst also protecting customers' financial security.

Our approach to developing UMs recognises this important trade-off between agile investment to support customers' evolving needs and bill stability. As explained in section 4, we have carefully prioritised our additional UM proposals to prevent an excessive number of mechanisms and ensure that less uncertain activities are funded from baseline allowances.

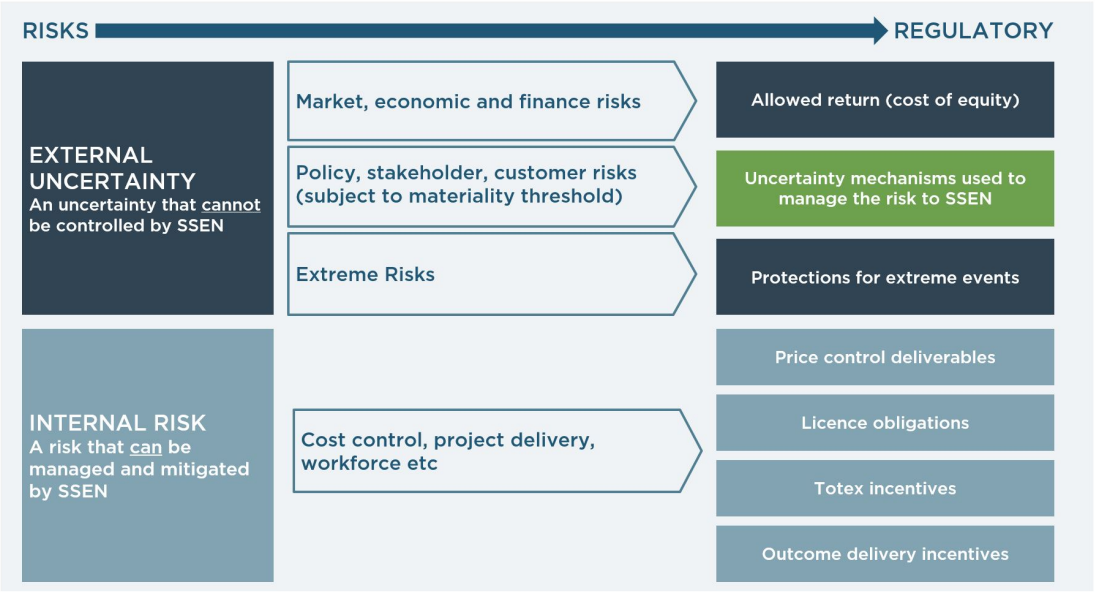
How do UMs fit into the broader framework for risk management?

As well as recognising the trade-off between flexibility and bill stability, our approach towards targeting UMs has also been informed by a wider understanding of how UMs support DNOs' risk management. This can be captured through two key frameworks, which place UMs in the context of broader risks and uncertainties facing DNOs (as described earlier in this section).

Regulatory tools to manage uncertainty

The first of these frameworks is captured in Figure 2.1 below. Our framework distinguishes between **internal risks**, which can be managed and mitigated by DNOs, and **external uncertainties**, which cannot be controlled by DNOs. This demonstrates how UMs are just one of many regulatory tools that DNOs can use to manage uncertainty during RIIO-ED2.

Figure 2.1: Regulatory tools for risk management in RIIO-ED2



As shown in Figure 2.1, prominent internally managed risks include the need for efficient operational cost management and timely project delivery. There are several regulatory tools which hold DNOs to account for these outcomes, including licence obligations, price control deliverables and outcome delivery incentives. The totex incentive mechanism (TIM) also provides some protection for both the DNO and its customers in the event of cost overspend.

Alongside these regulatory tools, we also use a comprehensive risk reporting and management framework to capture and mitigate internal risks. This multi-level framework incorporates 11 Principal Risks defined for our Network businesses, under which hundreds of component risks are actively documented and managed. The framework includes a full risk register which is used to document active risk mitigation procedures and is updated regularly. By using this risk register, we can proactively identify and reduce the cost impacts of downside risk outcomes, which ultimately reduces the use of regulatory tools in managing internal risks.

Beyond internal risks, there are also a range of external uncertainties to consider, which include the uncertainty drivers listed above. Importantly, the RIIO-ED2 framework provides several regulatory tools for managing external uncertainties. These include not only UMs, but also risk-sharing mechanisms for changes in the external economic environment. For example, the allowed return on capital notably includes indexation mechanisms which protect DNOs from some financial market movements.

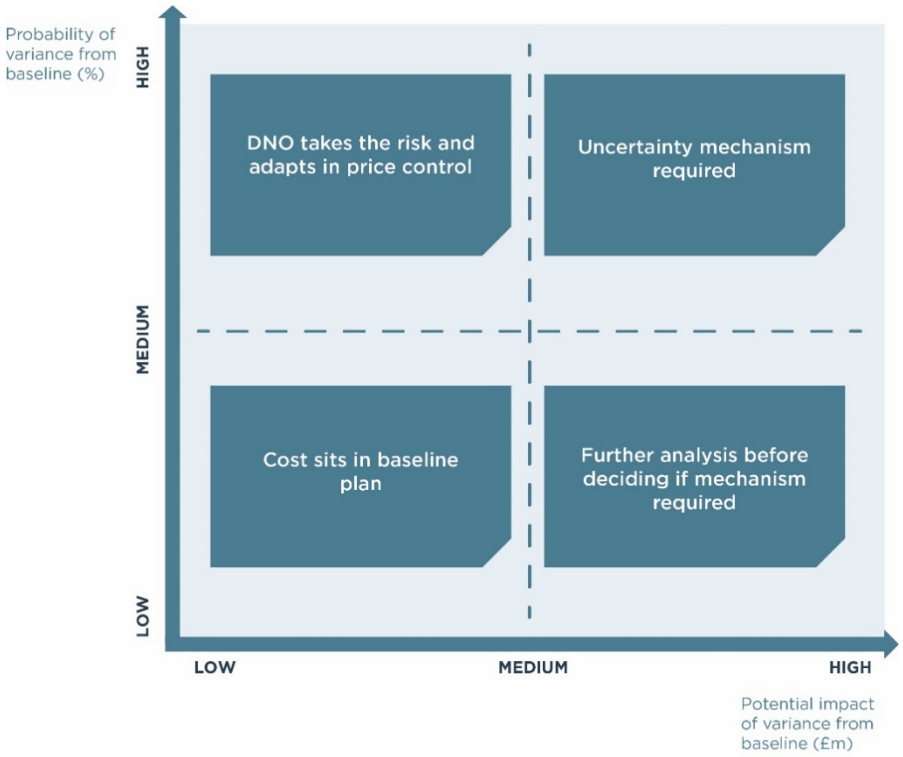
This framework provides important considerations when developing UMs. Perhaps most importantly, it recognises that UMs should be targeted towards specific, measurable uncertainties which will become more certain over RIIO-ED2, rather than being used as a catch-all mechanism for extreme events which are unlikely to materialise. Together with the allowed return on capital, UMs allow DNOs to efficiently manage the cost impacts of external developments.

The design and implementation of UMs (and other regulatory tools) is not intended to eliminate risk to DNOs. Rather, we are incentivised to manage risks in its control and allowed to recover a return on capital for bearing external market risk. This allowed return is carefully calibrated to the systematic risk the business bears.

Prioritisation of need for UMs

The second of our frameworks is captured in Figure 2.2. This demonstrates that even where risks or uncertainties are influenced by external events, DNOs have a responsibility to manage the resulting costs where possible, targeting UMs towards the uncertainties with greatest potential materiality.

Figure 2.2: Uncertainty materiality framework



As shown in Figure 2.2, we can consider the potential impact of uncertainties using a 2x2 matrix, which accounts for the probability of variance from baseline allowances, and the potential impact of variance from baseline allowances. If a given uncertainty has a low potential impact of variance, then it is insufficiently material to warrant an UM, implying that the DNO should instead seek baseline funding (with the appropriate supporting evidence), and manage the impact of future cost variances.

Similarly, if a given uncertainty is more material but has a low probability of variance from baseline, then the need for an UM should be carefully considered, noting the aforementioned point that broader regulatory protections exist for high-impact, low-probability events.

The most compelling UMs are those where both the probability and impact of variance from baseline are material, creating a reasonable likelihood of significant cost variances. This is most likely to arise where the baseline funding allowance is contingent on a greater range of forecast assumptions, which are sensitive to future change.

In developing our UMs, we have referred frequently to these frameworks, both of which have been validated with stakeholder groups. They have closely informed our suite of proposed additional UMs, which are described in detail later in this document.

What are the sources of uncertainty for our UMs?

By carefully testing potential UM candidates against the trade-offs and risk management frameworks described above, we have developed a set of proposed additional UMs. When combined with the UMs proposed by Ofgem in its RIIO-ED2 SSMD, these represent our complete set of RIIO-ED2 UMs.

Our UMs incorporate a range of uncertainties, each of which has the potential for significant cost impact over RIIO-ED2. In Table 2.3 below, we describe the primary sources of uncertainty for our UMs, and we categorise our UMs according to the most relevant source(s) of uncertainty. We note some UMs deal with more than one primary source of uncertainty.

This table focuses only on those UMs described in detail within this document and does not include Ofgem's proposed UMs linked to financeability and the allowed return on capital, or the automatic pass-through of unavoidable costs. For more information on these UMs, we refer the reader to the Finance chapter within our RIIO-ED2 business plan ***(Finance and Financeability (Chapter 19).***

Table 2.3: Sources of uncertainty for our complete set of RIIO-ED2 UMs

Uncertainty source	Description	Relevant RIIO-ED2 UMs (proposed by Ofgem or us)
Public policy uncertainty	Decisions of government bodies may impact the costs incurred by us	• Subsea Cables • Hebrides and Orkney Whole Systems • Cyber Resilience • Wayleaves and Diversions • Electricity System Restoration (Black Start) • Environmental Legislation • Street Works • Net Zero • Enhanced Physical Site Security
Stakeholder uncertainty	Decisions of non-government stakeholders may impact the costs incurred by us	• Wayleaves and Diversions • Rail Electrification • Co-ordinated Adjustment Mechanism (CAM)
Energy market development uncertainty	Changes in the profile of supply and demand may impact the costs incurred by us	• Strategic Investment • Smart Meter Interventions
Contractual uncertainty	Ofgem or third-party contractual decisions may impact the costs incurred by us	• Shetland

3. LESSONS LEARNED FROM OUR EXPERIENCE AT RIIO-ED1, AND OFGEM'S DECISIONS AT RIIO-ET2, RIIO-GT2 AND RIIO-GD2

In this section, we describe how our experience at RIIO-ED1 and our review of Ofgem's decisions for the RIIO-ET2, RIIO-GT2 and RIIO-GD2 price controls have informed our approach to developing uncertainty mechanism proposals for RIIO-ED2.

We begin by capturing key reflections on our UM package at RIIO-ED1, focusing particularly on challenges we faced in using the available re-openers, and we make a series of recommendations for change at RIIO-ED2. We then highlight key observations arising from our review of Ofgem's RIIO-T2 and RIIO-GD2 final determinations, and we explain how these observations have shaped our RIIO-ED2 proposals.

3.1 Lessons learned from our experience at RIIO-ED1

At RIIO-ED1 final determination, we were granted a series of UMs, most of which are applicable to all DNOs (except for mechanisms for Shetland and Subsea cables, both of which are only applicable to us). Our package of RIIO-ED1 UMs incorporates a range of mechanism types, including automatic allowance adjustment mechanisms (such as indexation and pass-through mechanisms) as well as a volume driver for smart meter roll-out costs and a series of in-period re-openers.

Whilst our RIIO-ED1 re-openers cover a range of specific cost drivers, the opportunities to apply for additional funding have been limited to certain pre-defined years. It is important to note that we have not used all re-openers available to us at RIIO-ED1: of nine available re-openers (excluding Shetland costs), we have only submitted re-opener applications for three to date (High Value Projects, Rail electrification and Subsea cables). Moreover, of the £100.0m additional funding we requested under these re-openers in 2019, only £61.2m (61.2%) was granted by Ofgem. Across the sector, we calculate that only 29.0% of the re-opener funding requested by DNOs during the 2019 application window was granted by Ofgem. Some of the available RIIO-ED1 re-openers have not been used by any DNOs over RIIO-ED1 to date.

These observations emphasise that whilst UMs provide the capacity to adjust DNO allowances upwards or downwards based on external developments, it is highly unlikely that all available UMs will be used by a single DNO during a price control period. This creates a need to build in sufficient flexibility at RIIO-ED2, recognising that different DNOs will face different cost challenges based on external developments in their licence areas.

Based on our experience at RIIO-ED1, we have considered our key reflections for how to design and implement effective UMs at RIIO-ED2, which work in customers' interests. We set out these reflections, which focus primarily on re-opener design and application, below.

Scope and flexibility

Our first reflection concerns the overall scope and flexibility of our RIIO-ED1 UMs. Notably, with the exception of the re-opener for High Value Projects, our RIIO-ED1 UMs are largely focused on specific expenditure areas or events. Whilst this has provided clarity over UM scope, it has restricted the flexibility of the overall UM package in adjusting for material new uncertainties (and additional unforeseen costs) that have emerged during the RIIO-ED1 period to date. The High Value Projects re-opener has offered some flexibility for unforeseen costs, but it has a substantially higher materiality threshold than the standard threshold applied to other mechanisms, which has restricted its potential application. Over RIIO-ED1, there have been several instances where detailed licence modifications have been required to grant DNOs significant additional funding for unforeseen events, partly due to a lack of existing UMs that cover the scope of these events, for example on subsea cables.

Looking ahead to RIIO-ED2, we consider there is a need for greater flexibility in the overall package of UMs, which reduces the likelihood of incurring substantial unforeseen and unavoidable costs, or the need to use other less appropriate regulatory mechanisms or ad hoc changes to the licence or regulatory framework. We note that Ofgem's RIIO-ED2 SSMD proposals include UMs for Strategic investment and net zero legislation. We welcome the flexibility these will provide given the need to decarbonise our network in line with the broader UK economy (although as we note later in this document, Ofgem should allow DNOs to trigger the net zero re-opener). We also recognise that the transition to a five-year price control slightly reduces the risk of unforeseen costs (although the scope and nature of the cost uncertainties we face will be different at RIIO-ED2).

It is important though that the final package of RIIO-ED2 UMs provides sufficient flexibility, including through the consideration of stakeholder views and the adoption of additional UMs proposed by DNOs, whilst also recognising the need to avoid an excessive number of mechanisms.

This includes incorporating sufficient flexibility for us to respond to evolving stakeholder needs over RIIO-ED2, ensuring that we maintain high service quality.

Re-opener windows

Our second reflection concerns the use of infrequent, time-limited, and narrow re-opener windows. Whilst we agree that re-opener windows provide transparency and support forward planning, we also consider that these windows should be sufficiently frequent to allow DNOs to submit applications at the appropriate time. We have found that the infrequent re-opener windows available for some RIIO-ED1 mechanisms have limited our ability to develop timely, well-evidenced re-opener applications, resulting in unrecovered costs and substantial delays in resolving whether additional funding is required (and awarded).

Looking ahead to RIIO-ED2, we note that Ofgem’s SSMD proposes to decide the relevant Regulatory Year(s) for re-opener windows on a case-by-case basis (with these windows being one weeklong and in late January by default). We consider that the default approach for RIIO-ED2 should be to allow annual re-opener application windows, unless there is a clear reason why this is not appropriate (for example, an UM is only needed for the first half of RIIO-ED2 and not the second half). This approach will allow DNOs greater flexibility to develop high-quality re-opener applications over RIIO-ED2.

We believe that this will ultimately benefit not only ourselves but also our customers, in that it enhances the timing and probability of success of our re-opener applications, reducing the time and resource spent on unsuccessful applications (and the need to prioritise associated investment over other projects).

Submitting a re-opener application

Our third reflection concerns the process involved in submitting re-opener applications to Ofgem. Over RIIO-ED1, we have submitted multiple re-opener applications, and we have found the application process sometimes inefficient and time-consuming. A key area of challenge has been understanding Ofgem's concerns and providing the relevant follow-up information required to address concerns and secure Ofgem approval in time for the Annual Iteration Process (AIP). Our RIIO-ED1 re-openers typically have application windows in May, leaving relatively limited time for the exchange of supporting evidence and detailed conversations given that the results of the AIP are typically published in November. We have found that Ofgem often requires substantial depth and breadth of supplementary information not asked for in the original submission guidelines before reaching decisions, and at times this information has been sought through repeated email correspondence when holistic conversations at an early stage could have expedited the decision-making process.

Looking ahead to RIIO-ED2, we note that Ofgem's SSMD proposes to bring re-opener application windows forward from May to January. We support Ofgem's proposal to bring application windows forward, as this will increase the available time for clarification, cross-party discussion, and additional evidence before the AIP process. This will enable DNOs and Ofgem to better evidence and test the case for additional re-opener funding.

To further support timely decision-making, we advocate that the streamlining of the re-opener application process undertaken by Ofgem in its RIIO-T2 and RIIO-GD2 final determination is also applied for RIIO-ED2.

This includes the development of a re-opener application pipeline log to ensure common visibility of anticipated re-opener applications, and a tiered assessment system for applications (informed by the materiality and complexity of the application) to ensure proportionality.

Ofgem should also allow for re-opener process extensions for individual applications, where this is required to support effective decision-making, particularly in more complex cases or where wider stakeholder engagement or input is required. This will further ensure that Ofgem's decisions over re-openers are driven by the quality of the underlying evidence, and not by process-related considerations.

3.2 Observations from Ofgem's T2 and GD2 final determinations which have influenced our proposals

As part of developing our UMs, we have reviewed Ofgem's decisions from the T2 and GD2 final determinations, and we have carefully considered the implications for our own proposals. Our review has highlighted several key observations, which have guided our thinking. We describe each of these observations in turn and explain how they have influenced our proposals.

1. Ofgem UM acceptance rate

Firstly, we note that the overall Ofgem acceptance rate for companies' bespoke UM proposals was relatively low across the T2 and GD2 controls, except for the GT sector. Some network companies proposed a substantial number of UMs in their business plans, only for the majority of these to be rejected by Ofgem. This emphasises the need to carefully test proposed UMs against Ofgem's business plan guidance, taking note of Ofgem's assessment feedback from draft determinations. In this feedback, Ofgem notes that rejected bespoke UMs generally failed to meet one or more of the following criteria:

- Sufficient justification of the uncertainty
- Sufficient information to implement the mechanism
- Sufficient evidence of potential drawbacks and value for money

In developing our proposals, we have been mindful of the high evidential threshold required to secure UM acceptance, recognising the need to ensure alignment with customers' interests and secure value for money for consumers. In doing so we have also considered the need to avoid an excessive number of UMs which risks creating excessive bill volatility for customers.

The first step in our process for developing additional UMs therefore involved testing our initial list of candidate uncertainty areas against Ofgem's criteria, and de-prioritising those areas where the business plan guidance requirements were not clearly met. For example, we deprioritised visual amenity cost uncertainties on grounds of materiality (visual amenity uncertainties are more substantive in transmission businesses). This process enabled us to prioritise the most robust additional UM proposals, and in section 6 of this document we describe each of our proposed UMs with reference to Ofgem's requirements, showing how these requirements are met. This includes detailed explanation required for implementation of the mechanisms.

We have also tested our proposals extensively with internal and external stakeholders, as described further in sections 4 and 5, and we have used stakeholder views to inform the de-prioritisation and refinement of our proposed UMs.

2. Use of common UMs

Secondly, we note that where Ofgem accepted the need or principle for an additional UM, it tended to apply the UM on a common basis (either across all sectors or all companies within a sector), rather than accepting UMs on a company-specific basis.

In developing our proposals, we have therefore considered the applicability of our proposed additional UMs to other DNOs, limiting the number of proposals which are specific to our SEPD or SHEPD licence areas (whilst recognising that some RIIO-ED2 uncertainties are regional by nature). We have also initiated engagement with other DNOs to test our proposals and gauge support, and we will continue to work with Ofgem and other DNOs to collaboratively develop UMs across several policy areas.

In this Annex, we have signposted the 'our-proposed UMs' which we consider applicable to other DNOs, distinguishing these from UMs which we consider truly unique to one or both of our licence areas.

3. Cross-sector UM applicability

Thirdly, our review of the T2 and GD2 final determinations identified several UMs which arguably have equal (or greater) applicability to the electricity distribution sector. We included these UMs within our initial list of candidate uncertainty areas, and line with our approach to the broader set of identified uncertainties, we de-prioritised those with a less compelling case, leaving a set of prioritised proposals. One of our proposed additional UMs for RIIO-ED2 has been strongly influenced by our T2 and GD2 review:

- Our proposed UM for Wayleaves and Diversions is influenced by the close out mechanism for landowner compensation which Ofgem granted to Scottish Hydro Electric Transmission (SHET) at ET2. The award of this mechanism follows Ofgem's decision to reject SHET's proposed re-opener for landowner compensation costs, instead deciding that costs should be adjusted at the end of the ET2 period (rather than in-period through a re-opener). Our proposed re-opener for Wayleaves and Diversions is importantly narrower than SHET's proposal, and we propose that costs associated with compensation of injurious affection claims should be adjusted using a close out mechanism, in line with Ofgem's ET2 approach. In our detailed description of the Wayleaves and Diversions re-opener (within section 6), we explain why we consider a re-opener approach to be more suitable than a close out mechanism for diversions costs specifically.

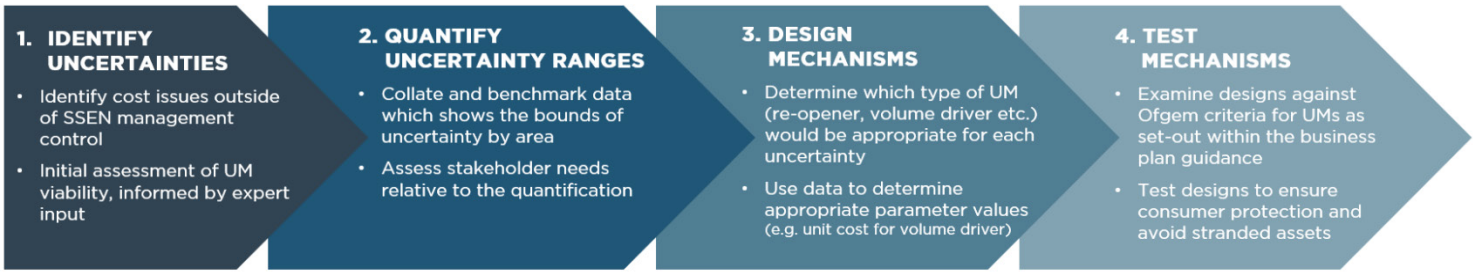
4. OUR APPROACH TO DEVELOPING UNCERTAINTY MECHANISMS AT RIIO-ED2

In this section, we explain how we have developed our proposed additional UMs. We set out the four-step framework we have used to identify, quantify, design and test our mechanisms, and we show how this framework has been applied across each of our mechanisms.

Our four-step framework for developing additional UMs

In Figure 4.1 below we set out our four-step framework for developing additional UMs. We have applied this framework across each of our proposals, and we have additionally gathered and incorporated feedback from a range of internal and external stakeholders throughout the development process.

Figure 4.1: Framework for developing additional UMs



We summarise each of the four steps below, and we show how they have been applied across each of our proposed mechanisms.

Step 1: Identifying uncertainties

Our process

Our first step involved identifying candidate uncertainty areas which may be suitable for an UM, and then narrowing down the list of options based on Ofgem's key criteria. To identify key cost uncertainties faced by us at RIIO-ED2, we drew on a range of sources, including:

- Our existing UMs from ED1.
- Engagement with internal business leads and subject matter experts.
- Engagement with Ofgem and peer DNOs.
- A targeted review of our risk register, which incorporates a wide range of business risks.
- Analysis of Ofgem's final determinations for T2 and GD2.
- Consideration of uncertainty areas flagged by Ofgem in the RIIO-ED2 SSMD.

This allowed us to develop a longlist of uncertainty areas. Recognising the need to avoid using too many UMs (given the effects on customer bill volatility), we then de-prioritised uncertainty areas which we consider to be less suitable for an UM. We used Ofgem's guidance to inform our de-prioritisation decisions, and we provide a detailed breakdown of the reasons for de-prioritisation in Appendix C. Prominent reasons for de-prioritisation included:

- Lack of a clear needs case for additional investment at RIIO-ED2, and/or consumers contributing to additional investment (recognising that some risks and uncertainties should be absorbed by DNOs or managed through other regulatory tools, as we emphasise in section 2).
- Lack of clear external trigger(s) for UM use.
- Lack of sufficient uncertainty, where there is high degree certainty on future cost impacts, which mean that funding should be sought through baseline allowances rather than an UM.
- Lack of sufficient cost materiality.

Following our de-prioritising of some uncertainty areas, we defined a set of prioritised uncertainties to take forward for UM development, incorporating Steps 2, 3 and 4 in our process.

Table 4.2: Summary outcomes from Step 1 for our proposed additional UMs

UM name	Outcomes from Step 1
Wayleaves and Diversions	• Identified through reviewing T2 mechanisms and our internal engagement. • Land right holders may terminate wayleave agreements for reasons outside our control, creating a need for diversion works. • There is significant uncertainty over how many terminations will occur each year, which is ultimately driven by land right holders' decisions to pursue terminations (this falls outside of our control). • There is also significant uncertainty over the cost of resulting diversion works. This is driven by historic volatility in the annual cost of diversions, which in turn reflects how the costs involved can vary significantly depending on the land area involved and the volume/voltage level of network assets crossing the land. • Together, these factors mean that outturn costs may vary significantly from the baseline allowances.
Shetland	• Identified by reviewing existing mechanisms for ED1. • Some future Shetland costs are outside our control - these may cause deviation from baseline Shetland costs.

Subsea Cables	• Identified by reviewing existing mechanisms for ED1. • For RIIO-ED2 we are proposing baseline-funded proactive replacement and general repairs on its subsea cables, but there remains a risk of unforeseen cable faults, which we cannot fully control. These faults may require substantive remedial reactive works, including reactive cable replacement, the costs of which are not captured in the baseline plan.
Hebrides and Orkney Whole Systems	• Identified post draft submission and through further engagement with stakeholders. • In two regions of our license area: Hebrides and Orkney islands we have two vectors of uncertainty going into the RIIO-ED2 period: 1. **Uncertainty on the driving need to act** (*CfD auctions in late 2022, further charging reviews (e.g. TNUoS), SGN review of LPG/LNG provision, solution to replace diesel gen sites on islands*) 2. **Uncertainty over the optimal type of action which is interdependent on the wider stakeholders in the region** (*whole system assessment is needed across multiple energy vectors*) • Risk of material regret for consumers if we fully commit to a solution now without more detailed whole system thinking in the next 18 months
Distributed Generation Monitoring	• Identified through internal engagement following publication of the findings of Ofgem's call for evidence on the issue. • The results of Ofgem, the ENA and DNOs' ongoing consultation on this issue could impose significant costs on us, but this need would only be identified after our business plan submission.
Polychlorinated Biphenyls	• Identified through Ofgem working groups (and recognised by Ofgem) and experience within the ED1 period. • We must comply with The European Commission new Regulation on Persistent Organic Pollutants, which requires the removal of Polychlorinated Biphenyls (PCBs) from our network by end of 2025. • DNOs generally have limited visibility of the prevalence of PCB on their network, as this was not information previously required to be logged or monitored. We have established an internal asset data task force to understand prevalence of PCBs and requirements for asset replacement.

	• Equally the scale of the deliverability challenge to meet the legislative date is different across DNOs depending on the scale of historical deployment of asset types containing PCBs. • Data is being provided on an ongoing basis through sampling, but full visibility of work required will not be known fully until into the RIIO-ED2 period.
Ash dieback removal	• Identified through our internal engagement. • Since its first identification in the UK in 2012, Ash dieback has been detected in over 60% of 10km^2 in the UK. Research has shown that less than 20% of the UK's Ash population is tolerant to the disease. • We must remove vegetation which are in proximity to our network that cause a safety and/or security of supply risk. • The volume of trees in proximity of contact with our network is unknown and the costs for tree removal can be variable, depending on rate of intrusion of the disease. Further survey work is required to determine costs and volumes we must incur.
OpEx adjustor	• Identified post draft business plan submission and review of final determinations for RIIO-T2. • Baseline OpEx (CAI and NOC) does not include provision to deliver UMs. Some UMs will require a substantive OpEx adjustment which will need to be accounted for.
Strategic Investment	• Suggested by Ofgem in the RIIO-ED2 SSMD. • Future of energy demand determined by external policies/trends like electric vehicle (EV) market development which are outside our control. • The additional network capacity required could vary significantly relative to baseline proposals, necessitating a UM. The existing ED1 load-related re-opener mechanism would not provide sufficient flexibility to manage the increased market uncertainties in RIIO-ED2.

Step 2: Quantifying uncertainties

Our second step involved quantifying the cost uncertainty associated with each of our uncertainty areas. To do this, we worked closely with internal experts to develop cost uncertainty ranges, which aim to capture the full set of potential cost impacts over RIIO-ED2 (from low to high).

Our approach to quantifying uncertainties varied based on the nature of the uncertainty, and on the available evidence. We distinguished discrete uncertainties from continuous uncertainties based on the range of possible outcomes, which informed our estimation approach.

- Discrete uncertainties are those with a finite set of possible outcomes, each with an associated cost impact (for example, uncertainty over possible implementation of a new government policy). To quantify these uncertainties, we sought to define the possible scenarios and estimate the cost impacts to us under each one (drawing on historic data, RIIO-ED2 projections and expert insight), thereby creating a range of possible costs.

- Continuous uncertainties are those characterised by continuous distributions with a very large set of possible outcomes and cost impacts (for example, uncertainty over the number of electric vehicles purchased by consumers over RIIO-ED2). To quantify these uncertainties, we drew on historic cost distributions where possible, and we developed forward-looking scenario analysis with expert input.

We align and orientate the uncertainty ranges around the baseline RIIO-ED2 funding proposals. This enables us to show where the baseline proposals fall within the uncertainty range, which in turn allows us to calculate the net financial impacts of our UMs (including customer bill impacts).

Our uncertainty ranges also account for the broader characteristics of each uncertainty, including:

- Profile (is the uncertainty two-sided relative to baseline costs, or one-sided?).

- Timing (does the uncertainty materialise at specific points in time, or throughout RIIO-ED2?).

- Dependencies (is the uncertainty dependent on or impacted by other elements of the RIIO-ED2 business plan?).

Table 4.3: Summary outcomes from Step 2 for our proposed additional UMs[11]

UM name	Outcomes from Step 2

Wayleaves and Diversions	• Continuous uncertainty.
	• Cost uncertainty ranges:
	  ○ SEPD: £35.6m to £80.1m, relative to a baseline of £44.8m (-£8.9m to +£35.3m)
	  ○ SHEPD: £1.3m to £4.0m, relative to a baseline of £2.6m (-£1.3m to +£1.4m)
	• We used historic costs from previous price controls to estimate the uncertainty range
	• N.B. Costs variation to baseline for Injurious Affection claim costs we propose to treat as an end of RIIO-ED2 period close out mechanism and are not included in the above cost materiality range.

Shetland	• Discrete uncertainty. • Cost uncertainty ranges (SHEPD only):

[11] All cost uncertainty range figures presented in Table 4.3 are rounded to the nearest £m, including positive and negative variances relative to baseline expenditure.

	○ SHEPD: £87.1m to £113.8m, relative to a baseline of £99.8m (-£12.7m to +£14.0m) • We used 'rolled on' ED1 costs for the extension of existing arrangements, and the latest SHEPD projections for the transmission link and future standby solution to infer our cost uncertainty estimates, based on market tested information. • N.B. Pass through and our proposed UM to cover variation in contribution to the transmission link is excluded from range as this would be a RAV transfer rather than a totex adjustment.
Subsea Cables	• Continuous uncertainty. • Cost uncertainty ranges (SHEPD only): ○ SHEPD: £0 to £75.7m, relative to a baseline of £0 (£0 to +£75.7m) • For reactive replacement, we used historic SHEPD data on annual cost of subsea cable faults over ED1 to develop the cost uncertainty range. • For remote generation, our cost uncertainty range was informed by historic SHEPD data on the costs of mobile and embedded generation tied to subsea cable fault response over 2020-21. • N.B. our relative baseline is zero since we have no reactive replacement costs in our baseline plan, only proactive ones and fault maintenance costs
Hebrides and Orkney Whole Systems	• Discrete uncertainty • Cost uncertainty ranges (SHEPD only): ○ SHEPD £151.2m to £275.6m relative to a baseline of £151.2m (-£151.2m to +£275.6m) • For the lower range we set an assumption the UM would remove £151m of baseline spend from our plan because third party whole system solution is more economic • For the upper range we don't know what whole system solutions could outturn, so to set a range we have calculated the 'do minimum lifetime costs' for distribution. Continuation of the existing security of supply solutions (diesel) or further subsea cable investment is the do minimum cost
Distributed Generation Monitoring	• Discrete uncertainty. • Cost uncertainty ranges: ○ SEPD: £0 to £24.1m, relative to a baseline of £0 (£0 to +£24.1m) ○ SHEPD: £0 to £16.7m, relative to a baseline of £0 (£0 to +£16.7m) • We considered the potential upper end of DG monitoring costs across sites in four voltage categories (EHV, HV, LV half hourly metered and LV non-half hourly metered). Summing the likely upper end for each of these together generated the uncertainty ranges given above.
Polychlorinated Biphenyls	• Continuous uncertainty. • Cost uncertainty ranges: ○ SEPD: £28.4m to £44.7m, relative to a baseline of £28.4m (£0m to +£16.3m) ○ SHEPD: £13.2m to £34.4m, relative to a baseline of £13.2m (£0m to +£20.1m)

	• This is based on latest data for replacement of pole and ground mounted transformer sites which we believe to contain PCBs and will need to be replaced by the end of 2025 legislative date and are not certain enough to include within the baseline or accelerated ED1 funding.

Ash dieback removal	• Continuous uncertainty
	• Cost uncertainty ranges
	  ○ SEPD: £0 to £38.0m, relative to a baseline of £0 (£0 to +£38.0m)
	  ○ SHEPD: £0 to £10.0m, relative to a baseline of £0 (£0 to +£10.0m)
	• This estimate is based on latest data on the abundance of Ash dieback in our licence area and current cost experience of removing these trees, which is a function of disease intrusion and can be up to five times more expensive than conventional tree removal.

OpEx adjustor	• Continuous uncertainty
	• Cost uncertainty ranges
	  ○ SEPD: £493.4m to £598.8m, relative to a baseline of £502.4m (-£9.0m to +£96.4m)
	  ○ SHEPD: £275.6m to £313.4m, relative to a baseline of £278.8m (-£3.3m to £34.5m)
	• We propose for CAI the percent increase would be set on a consistent basis to the approach used to determining efficient CAI baseline allowances i.e. using the coefficient for CapEx from the POLS regression analysis at Draft Determinations. However, in advance of this we have calculated for using available information from all DNO draft plan submissions (excluding UK Power Network) a regression coefficient of 0.3035% for CAI.

Strategic Investment	• Continuous uncertainty.
	• Cost uncertainty ranges:
	  ○ SEPD: £206.0m to £408.9m, relative to a baseline of £226.8m (-£20.8m to +£182.1m)
	  ○ SHEPD: £61.6m to £129.2m, relative to a baseline of £71.2m (-£9.5m to +£58.2m)
	• We used DFES 2020 scenarios and associated load-related investment forecasts to determine the upper and lower bounds for our cost uncertainty ranges. These scenarios are driven by different assumptions over the growth of low carbon technologies (LCTs) such as EVs and heat pumps over RIIO-ED2.

Step 3: Designing UMs

Our third step involved designing appropriate mechanisms for each uncertainty, based on the nature of the uncertainty and its characteristics.

We first considered which mechanism type to apply. Although Ofgem's RIIO-ED2 SSMD defines five different types of UM (re-opener; volume driver; pass-through; indexation; use-it-or-lose-it (UIOLI) allowance), the majority of our mechanisms are re-openers or volume drivers and of the other three mechanism types, we only propose to use pass-through mechanisms (specifically in relation to our Shetland power station fuel cost uncertainties, which represents a continuation of the current ED1 arrangements). Our non-use of Indexation or UIOLI allowances reflects how our proposed mechanisms involve uncertainties over volume delivery, and the costs involved are often specialised with no price indices to refer to.

In deciding between re-opener and volume driver mechanisms, we carefully considered the scope of potential costs, the nature of external triggers and the level of certainty over unit costs. An advantage of volume drivers over re-openers is that they allow for automatic adjustment of allowances in line with volumes delivered, but they require sufficient certainty over both the scope of potential costs and the level of unit costs. There also needs to be a transparent means of safeguarding against excessive investment and over-delivery, thereby ensuring that the outturn level of investment is aligned with consumers' interests. Where these criteria are met, we have developed volume driver proposals, and where they are not met, we have instead proposed re-openers.

After deciding the mechanism type, we then defined our proposed parameters for each UM.

For re-openers, this involved defining a range of parameters including the materiality thresholds and application windows for each mechanism, as well as whether the mechanism should have an Ofgem trigger. Our default approach has been to follow the common re-opener parameters set out by Ofgem in the RIIO-ED2 SSMD, deviating from these parameters only where we consider this necessary and justifying why. Our broader position on Ofgem's common re-opener parameters is set out later in this document.

For volume drivers, this principally involved defining the unit costs for each mechanism. We define appropriate unit costs which balance the need for simplicity and transparency against the need for sufficient accuracy. However, we have also given careful thought to the external trigger events associated with each volume driver, and we have sought to build safeguard components into each mechanism which prevent greater volumes being delivered (and rewarded) which aren't in the interest of consumers. We explain these safeguards in greater detail within the detailed articulation of our proposals, but their aim is to tie the delivery of greater volumes to the outcomes that matter for network users (e.g. delivery of efficient additional capacity which avoids low network utilisation). This provides added protection for consumers.

Table 4.4: Summary outcomes from Step 3 for our proposed additional UMs

UM name	Outcomes from Step 3
Wayleaves and Diversions	• Re-opener for physical diversions to reflect uncertainty over both volume (number of diversions due to terminations) and average diversion costs (found to be volatile from ED1 experience). Standard materiality threshold trigger to incentivise cost control and reduce RIIO-ED2 bill volatility for customers. • Close-out mechanism for IA claims to reflect the greater predictability of these costs for the baseline compared to physical diversions, but recognised ongoing uncertainty based on changes in trends associated with land agent claims outside SSENs control which could result in higher or lower volumes of claims than foreseen at the start of the price control.
Shetland	• A set of UMs to reflect the uncertainty pre and post the construction of the transmission link, including costs associated with providing an enduring standby solution.
Subsea Cables	• Volume driver proposed for reactive replacement works, given reasonable certainty over unit costs when measured on a £ per km basis (with a reasonably strong historical correlation between length of cable replaced and outturn cost). The principal uncertainty is over volume of replacement required. • Re-opener proposed for remote generation. This reflects uncertainty over the volume of cable faults and the extent of remote generation backup required should faults occur, recognising that the costs of remote generation can fluctuate significantly depending on the location and severity of cable faults (as well as the supply areas requiring backup generation). • Re-opener proposed for cable decommissioning. This reflects the uncertainty over costs associated with the removal of decommissioned cables, given the limited precedent for this.
Hebrides and Orkney Whole Systems	• Re-opener proposed will allow for either upward or downward adjustment of baseline allowances, depending on required investment by SSEN. Triggered only within the first two years of RIIO-ED2 unless otherwise directed by Ofgem.
Distributed Generation Monitoring	• Re-opener proposed to reflect need and cost uncertainty. Similar to Radio Spectrum Allocation, the only viable alternative is a UIOLI allowance, but this would remove Ofgem's ability to scrutinise efficiency of investment at a relevant point in time. Additionally, our current view of the upper bound for costs in this area is reliant on numerous assumptions related to the nature of the decision made. An accurate assessment of costs can only be made once these caveats are made clearer. • The re-opener would be triggered by policy decisions made by Ofgem or related bodies that there is a needs case for a material amount of DG monitoring, and that the cost burden of such monitoring should fall on DNOs such as us (as opposed to other parties such as generators).

UM name	Outcomes from Step 3
Polychlorinated Biphenyls	• Volume driver proposed given the relative unit cost certainty of replacing assets containing PCBs whilst there is a volume uncertainty dependent on the outcome of further survey work. • The volume driver would be in place until at least 2026 with us adjusting allowances automatically each year based on reported replacements. The adjustment would be at the standard unit rates for the assets agreed at the start of RIIO-ED2. • A close our report would be provided to Ofgem with outcomes of survey work used to justify interventions. Ofgem would have ability to revise down total volumes funded only if evidence for replacement was not justified.
Ash dieback removal	• Re-opener proposed given the considerable cost and volume uncertainty. • Whilst the need to remove diseased trees is clear to prevent contact with assets and risks to safety and security of supply; the exact volume in proximity of contact is unclear as is the removal cost, which is dependent on disease intrusion. • We propose the re-opener would only be triggered once we have reached, through the cost of tree felling, the standard materiality threshold for a UM. To trigger the UM we propose we will submit to Ofgem a detailed report outlining costs and volumes for replacement to the end of RIIO-ED2 based on latest survey data of diseased trees in proximity to our assets.
OpEx adjustor	• Automatic adjustment based on the same formula used to establish the relationship between workload driver, CapEx and efficient CAIs in our baseline plan, to be determined by Ofgem at the Draft Determinations. This means there would be a percent increase of the baseline CAI allowance for each individual licensee for a 1% of increase of CapEx allowance above the baseline allowance through specified UMs.
Strategic Investment	• DNOs and Ofgem are working together to design this UM; Ofgem is minded to use a volume driver to ensure efficient allowance adjustment. Unit costs can be determined using regression analysis of cost per unit of capacity delivered, drawing on historical and forecast data.

Step 4: Testing our mechanisms

Our final step involved testing our proposed mechanisms against Ofgem's business plan minimum requirements and refining our proposals (including mechanism designs and parameters, mechanism scope and estimated materiality) to best align with these criteria. We have tested our proposals from a range of perspectives, involving internal and external stakeholders in this process. Our key testing considerations have included:

- Challenging the balance between baseline funding and UMs (testing why funding linked to UMs cannot be incorporated into baseline cost allowances or absorbed as an ongoing risk to manage by the company).

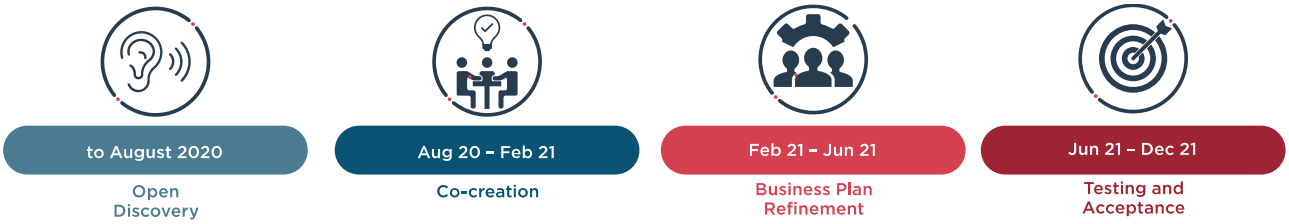
- Ensuring consumer value (from an economic, social and environmental perspective), and protecting consumers from under delivery.
- Avoiding stranded assets arising from over-investment.
- Avoiding us earning undeserved gains or losses from poor UM design and/or calibration.
- Ensuring alignment with the broader RIIO-ED2 business plan.

Table 4.5: Summary outcomes from Step 4 for our proposed additional UMs

UM name	Outcomes from Step 4
Strategic Investment	• We have engaged with cross-industry working groups on UM development, including other DNOs and Ofgem. • UM designed to ensure we are not incentivised to over-invest and create stranded assets, and that unit cost allowances are as representative/accurate as possible (bearing in mind the need for efficient delivery).
Wayleaves and Diversions	• We have targeted the scope of the re-opener to only include diversions as a result of wayleave terminations, deciding that injurious affection claims should be subject to an end-of-period adjustment mechanism. Our approach has been closely informed by discussions with SP Energy Networks (SPEN), which we have used to test and refine our proposals.
Shetland	• We have assessed the aggregate impact on consumers of the combination of Shetland UMs, to ensure any drawbacks (e.g. bill volatility) are outweighed by the benefits of ensuring Shetland's power is well-maintained. This is consistent with our approach in ED1. We have also allowed for future review of Shetland's standby supply, ensuring this best meets customer needs.
Subsea Cables	• We have tested our plans with internal experts, ensuring alignment with the broader RIIO-ED2 subsea cables strategy and wider stakeholder views. • We have refined our proposed mechanism design, distinguishing between proactive replacement (funded through baseline), and reactive replacement (funded through a volume driver). Our proposals will ensure that consumers only pay for the exact nature of the works we undertake.
Hebrides and Orkney Whole Systems	• We have pressure tested our proposals against our baseline investment proposals and the wide range of stakeholder feedback received from those with interests in the region.
Distributed Generation Monitoring	• We have sought to ensure the mechanism in this area has sufficient flexibility to cope with a wide variety of potential future DG monitoring policy decisions.
Polychlorinated Biphenyls	• We have included a proposed close out report with the ability for Ofgem to adjust volumes funded should there be evidence that the volumes automatically funded exceed that required to meet our legal obligations by 2025.
Ash dieback removal	• We have proposed a trigger event linked to the ongoing costs incurred from diseased tree removal. This means would only trigger after a standard materiality threshold has been exceeded; and we produce updated survey data on the costs and volumes for diseased tree removal in proximity of

UM name	Outcomes from Step 4
	asset contact. This ensures consumers are protected should the extent of the issue not be as extensive as currently believed.
OpEx adjustor	• We have sought to ensure the mechanism in this area has sufficient flexibility to cope with potential future indirect operating cost requirements required to deliver key activities including enabling customers to connect and meeting our legal obligations, for example in relation to PCBs
Strategic Investment	• We have engaged with cross-industry working groups on UM development, including other DNOs and Ofgem. • UM designed to ensure we are not incentivised to over-invest and create stranded assets, and that unit cost allowances are as representative/accurate as possible (bearing in mind the need for efficient delivery).

5. OUR APPROACH TO STAKEHOLDER ENGAGEMENT



Our Uncertainty Mechanisms strategy has been informed by our Enhanced Engagement programme, full details of which are set out in ***Enhanced engagement strategy (Annex 3.1).*** Our draft plan was underpinned by three phases of stakeholder and customer engagement (illustrated in the diagram above). The details of this engagement and insights are set out in Appendix D to this Annex and provide a clear line of sight between what stakeholders told us and our Uncertainty Mechanisms strategy.

5.1 Final Uncertainty Mechanism Strategy Testing and Acceptance

We have refined our final Uncertainty Mechanisms strategy based on Phase 4 of our Enhanced Engagement, which involved direct testing of the strategy with 1,526 stakeholders through eight events. The table below sets out the clear line of sight of the changes between our draft and final Uncertainty Mechanisms strategy based on this engagement.

5.2 Engagement Evidence Triangulation and changes between Draft and Final Plan

We have continued to engage with stakeholders right across our plan since our draft submission. UMs have been discussed in four events: (1) Academic panels; (2) Bilateral engagements with national and local government; (3) The cost and output event; and (4) A bilateral with Citizens Advice. We have also heard from the Challenge Group and wider stakeholders through Ofgem Working Groups, such as on Access SCR reform.

Through these events and bits of feedback we discussed several key themes including working with uncertainty in the RIIO-ED2 period across the plan and ongoing collaboration with stakeholder groups. The conversations also touched on specific proposals including subsea cables and load (Strategic Investment).

The feedback has shaped our proposals for this final business plan submission in several ways:

- **Load related expenditure (Strategic Investment)** – stakeholders emphasised the need for plan optionality, and that a mechanism was needed. They want continued engagement on UM design
    - We have developed a proposed design using their feedback ***Strategic Investment UM (Appendix 17.1.1)*** and are engaging through the Ofgem Working Group, including ensuring stakeholder voices are heard in this group

- **Scottish Islands (subsea) –** we heard that most felt the UM for reactive replacement of faulted cables was necessary, but that stakeholders wanted more optionality to cover the need for additional capacity
    - We propose an additional UM in the Hebrides and Orkney to allow us to facilitate the outcomes of additional whole system analysis in the region
- **LV monitoring** – we heard the challenge from the Ofgem challenge group that they felt our UM approach in some areas risked creating a dis-incentive to find efficiencies in our baseline spend
    - We pressure tested our UM approach here relative to the baseline and felt on balance the UM was not suitable to include in the final RIIO-ED2 plan
- **Access SCR** – we reviewed the Ofgem 'minded to' decision and heard feedback from our customers that they still don't have enough information to change their plans for network connections
    - We have carefully reviewed the purpose of our draft plan UM against the 'minded to', stakeholder feedback and other UM and have proposed to remove it for final plan

5.3 Our Customer Engagement Group

We have engaged with the CEG specifically on the topic of UMs five times during our RIIO-ED2 business plan development, in July 2020, October 2020, March 2021, September 2021 and October 2021.

In our July 2020 session, we discussed broad principles for UMs in the context of the wider RIIO-ED2 framework, reviewed the UMs in place during ED1, and discussed our process for proposing robust UMs in our RIIO-ED2 business plan. We built on this in our October 2020 session by discussing Ofgem's SSMC, our initial prioritisation of potential UM proposals, and updates to our process for developing UM proposals. At our March 2021 session, we proceeded to discuss the detail of our UM proposals for the draft plan, and how we have assessed their financial impact.

Since our draft business plan submission in July 2021 we engaged with the CEG on two occasions. In September 2021 we heard the CEG's reflections on our draft plan, we also shared detail on feedback we had received from a range of stakeholders related to UMs; and we discussed customer bill impacts of the draft plan proposals. At the October 2021 session we deep-dived UM proposals on Wayleaves & diversions; LV monitoring, subsea cables, and PCBs. We also discussed our stakeholder feedback and crafting of the business plan narrative.

5.4 Peer DNO engagement

In developing our package of UMs, we have worked closely other DNOs, through the Ofgem working groups and the Electricity Networks Association (ENA). We have also held several conversations we have initiated with peer, through which we have discussed potential proposals for additional UMs and explored opportunities for collaborative mechanism development.

We have engaged with SP Energy Networks (SPEN) to consider proposals for UM(s) linked to wayleave terminations. Whilst the Wayleaves and Diversions UM described later in this document solely represents our own view of mechanism design, we reflected points from our engagement in the design.

We have continued our engagement in the Ofgem Load Related Expenditure (Strategic Investment) working group and discussed options with some DNOs bilaterally. These conversations have helped shaped the proposal which is covered in detail in ***Strategic Investment UM (Appendix 17.1.1)***

On PCBs several DNOs expressed a desire to explore a UM to fund the continued removal of assets containing these from our network, as the volume of assets becomes clearer during RIIO-ED2. Whilst the PCB UM described later in this document solely represents our own view of mechanism design, we have reflected on our engagement with others to set the scope and design of this mechanism.

6. OUR PROPOSED ADDITIONAL UNCERTAINTY MECHANISMS IN DETAIL

In this section, we describe each of our proposed additional UMs in detail, showing how these meet the requirements set out in Ofgem's business plan guidance.

Table 6.1 below summarises the additional UMs which are described in this section. We explore the issues addressed by each mechanism and their indicative materiality in greater detail within our UM-specific write-ups.

Table 6.1: Summary of our proposed additional UMs

UM name	Type of UM	Applicable to...	Issues addressed	Cost uncertainty range relative to RIIO-ED2 baseline
Our proposed UMs				
Wayleaves and Diversions	Re-opener	ED companies	Costs associated with uncertain diversions costs following wayleave terminations.	SEPD -£9m to +£35m SHEPD -£1m to +£1m
Shetland	Re-openers	SHEPD only	Costs associated with extended full duty supply arrangements pre-link, the process to implement the enduring solution, adjustments to the contribution towards the Shetland transmission link, and backup supply electricity to the Shetland islands, post construction of the new transmission link to the UK mainland.	SEPD N/A SHEPD -£13m to +14m
Subsea Cables	Volume driver & Re-openers	SEPD and SHEPD only	Costs associated with subsea cable replacement following damage or faults, additional remote backup generation and cable decommissioning.	SEPD Not quantified SHEPD £0 to +£76m
Hebrides and Orkney Whole Systems	Re-opener	SHEPD only	Costs associated with the outcomes of additional whole system analysis in the Scottish Islands to meet net zero to be undertaken in RIIO-ED2	SEPD N/A SHEPD -£151m to £276m
OpEx adjustor	Volume driver	ED companies	Costs associated with adjusting the efficient level of operating expenditure SSEN requires to deliver specific uncertainty mechanisms.	SEPD -£9m to £96m SHEPD -£3m to £35m

Distributed Generation Monitoring	Re-opener	ED companies	Costs related to the possibility of increased DG monitoring requirements resulting from Ofgem's review of the issue.	SEPD £0 to +£24m SHEPD £0 to +£17m
Polychlorinated Biphenyls	Volume driver	ED companies	Costs related to removing assets containing PCBs from our network by end of 2025 to meet legislative requirements.	SEPD £0 to +£16m SHEPD £0 to +£20m
Ash dieback removal	Re-opener	ED companies	Costs associated with removing Ash dieback diseased trees in proximity of contact with our network.	SEPD £0 to +£38m SHEPD £0 to +£10m
Strategic Investment	Volume driver	ED companies	Costs related to uncertain load-related expenditure driven by the net zero transition and rising demand for electricity.	SEPD -£21m to +£182m SHEPD -£9m to +£58m

6.1 Wayleaves and Diversions

a. Issues and risks that the proposed mechanism addresses

To operate and maintain our network apparatus in pursuit of net zero, including overhead lines and underground cables, we require access rights to privately owned land which our apparatus crosses. To secure access rights, we negotiate land access agreements with property owners (known as 'Grantors'). Negotiation surrounds rental and/or compensation where appropriate for the grant of the land right.

The two primary forms of land access agreements used are Wayleave agreements and Easements (also known as Deeds of Servitude in Scotland). These agreement types differ significantly in their permanence. Wayleave agreements are personal agreements between the network operator and the Grantor, in return for an annual rental or one-off commuted payment to the Grantor. By contrast, Easement (Servitude) agreements are permanent rights that form a burden on the property title, and they therefore run with the property and are binding on successors in title. As a result, Easements (Servitudes) are a non-terminable agreement. We seek to secure Easements (Servitudes) over Wayleaves where possible, to ensure efficient and sustainable land access.

As discussed above, Wayleaves are a terminable agreement. Grantors can seek removal of assets or a diversion of apparatus. When this happens, Network operators are time constrained to three months to either negotiate a mutually acceptable solution or lodge an application for Necessary Wayleave. Network system planning, valuation principles, compensation principles and planning principles all have to be understood in order that an appropriate strategy can be defined to best protect the UK bill payer. It might be that a mutually acceptable arrangement can be reached between Grantor and us or it might be that a retention of assets in their existing location is required and a Necessary Wayleave is pursued. A Necessary Wayleave is no guarantee of success and will likely give rise to a compensation claim which could be heard at a tribunal hearing.

There is uncertainty around the nature and quantum of termination and diversion costs. These challenges can range from individual householder led notices to remove to large scale housing developer claims running into millions of pounds. There are costs associated with initial strategic and planning work as well as the potential costs of reconfiguring the network when required. The costs of reconfiguring the network can vary significantly, and this in turn drives cost uncertainty at the aggregate level.

Throughout ED1, we have found that the annual cost of diversions has fluctuated significantly, due to volatility in the volume and average cost of works. This makes it challenging for us to accurately forecast diversions costs at RIIO-ED2, with the potential for costs to be significantly higher than our central projection should the volume and/or average cost of diversions differ materially from this projection. This is an issue that affects all distribution licence areas to some extent, although as we explain further below, this is a more critical issue on our Southern network given that many of our largest diversion works involve the 132kV network.

Our RIIO-ED2 business plan includes baseline funding proposals for diversion works, which have been calculated based on historic data and expert insight.

We are additionally proposing a re-opener UM which will adjust our allowances based on the realised cost of delivering physical diversion works. This will allow us to recover efficient additional costs as required to complete diversion works in a timely manner.

It is important to emphasise that diversion works are not the only potential outcome from a land access challenge. One of the alternative outcomes is that we may reach a compensation settlement with the Grantor to ensure continued land access, reflecting a loss of land value caused by the network apparatus. These settlements are known as Injurious Affection (IA) claims, and they may be initiated by Grantors even when they are not pursuing a Wayleave termination. Whilst the volume of IA claims has risen over ED1, reflecting the broader evolution of the claims market, the RIIO-ED2 costs of these claims are easier to predict than diversions costs due to relatively large sample sizes and stable average settlement costs.

As a result, we are not proposing a re-opener for IA compensation costs. We are instead proposing that Ofgem applies an RIIO-ED2 close-out adjustment for IA compensation costs, to reflect the efficient costs incurred. This would match the approach towards IA compensation costs adopted at T2 by Ofgem and SHET. We propose to strengthen the reporting of the costs arising from IA compensation cost within the annual regulatory reporting cycle. This will provide Ofgem and DNOs with greater visibility as costs are incurred and can therefore better prepare for the close out.

Our proposed approach recognises that whilst IA compensation costs are easier to predict than diversions costs, they are largely outside of our control and dependent on the future trajectory of IA claims initiated by Grantors (who are generally supported by claiming agencies). In keeping with the T2 approach, we consider that we should not benefit or be penalised through the TIM in relation to IA compensation costs, as any over or under-performance is not likely to be due to efficiency or inefficiency, but rather due to the nature of how the costs arise.

b. The design of the proposed mechanism

Our proposed mechanism for physical diversions is a re-opener, with the standard materiality threshold (1% of annual allowed base revenue). The re-opener will allow for either upward or downward adjustment of cost allowances, depending on outturn costs. We consider that there should be regular application windows available for this re-opener to provide the required flexibility to adjust allowances during RIIO-ED2.

The scope of the re-opener will include all costs relating to physical diversion works in the CV5 Business Plan Data Table, incorporating diversions due to wayleave terminations and diversions for highways.

Further we propose that Ofgem applies an RIIO-ED2 close-out adjustment for IA compensation costs, to reflect the efficient costs incurred. This would match the approach towards IA compensation costs adopted at T2 by Ofgem and SHET.

c. Ownership of risks under the mechanism

Under our proposed re-opener, ownership of risk will be shared between us and our customers. Given that the standard materiality threshold will apply, it will be our responsibility to manage the impacts of smaller cost variations which do not exceed the threshold. We will also bear the risk that requests for additional funding are rejected by Ofgem during the RIIO-ED2 period.

Our customers will bear the risk of higher bills, should additional diversions funding be awarded to us by Ofgem through the re-opener. However, the two-sided nature of the re-opener means that customers could experience lower savings should outturn costs be lower than our forecast.

This balance of risk is appropriate, as it incentivises us to manage diversions costs efficiently and minimise the need for diversion works. There is no guarantee that any requests for additional funding will be approved, and time investment will be required to prepare any re-opener applications, which will encourage us to control our costs.

However, our proposed re-opener also recognises that costs could be either higher or lower than forecast for reasons outside of our control, and it ensures that our customers' bills will reflect the realised costs of diversion works (noting our incentives to control costs). As explained further below, we consider that it is in customers' interests for us to agree and complete diversion works in a timely manner, noting that this is often the most cost-effective way to resolve Wayleave terminations.

d. Materiality of issue

To estimate the cost uncertainty associated with diversions at RIIO-ED2, we have drawn on historic data, RIIO-ED2 projections and expert insights. This has allowed us to define several scenarios for future diversions costs, reflecting how the cost of diversion works varies substantially across projects (with the possibility of very high costs for diversions involving the 132kV network).

For SEPD, we estimate a cost uncertainty range for physical diversions of £35.3m to £80.1m relative to a baseline spend of £44.8m (equivalently, this is -£8.9m to +£35.3m relative to the baseline). Our range accounts for uncertainty associated with both diversions due to wayleave terminations and diversions for highways, although the wayleave terminations component is much more material. Our range also accounts for outstanding claims associated with wayleave terminations, which has grown steadily over ED1. Our baseline plan includes a provision to address these outstanding claims over RIIO-ED2.

For SHEPD, we estimate a cost uncertainty range for physical diversion of £1.3m to £4.0m relative to a baseline spend of £2.6m (equivalently, this is -£1.3m to +£1.4m relative to the baseline). Our range accounts for uncertainty associated with both diversions due to wayleave terminations and diversions for highways, with the wayleave terminations component being more material.

The cost uncertainty range is materially larger for SEPD than SHEPD, reflecting how the most expensive diversion works often relate to the 132kV network in the SEPD region.

Although our uncertainty range is smaller for SHEPD, there is still uncertainty over outturn RIIO-ED2 costs, with the potential for higher costs as the market for wayleave terminations continues to evolve. Given this uncertainty, we consider that the re-opener should be available for both our SEPD and SHEPD licence areas.

The range for IA compensation costs is unknown at this stage and we propose will be managed through a close out adjustment mechanism.

e. Frequency and probability of issue

The cost of diversion works fluctuates every year and will naturally vary from our baseline forecast. Whilst our proposed re-opener includes annual application windows, it is very unlikely that the re-opener will be triggered every year, with more occasional use most likely.

We forecast that there is a higher probability of the re-opener being triggered in our Southern licence area. This is because many of our more expensive diversion works have historically occurred on the SEPD 132kV network, with wayleave terminations often triggered by land developers. Our Northern licence area does not have a 132kV network, as the 132kV network in north Scotland forms part of the transmission system.

f. Justifications for the proposed mechanism

Our proposed re-opener will allow for the efficient recovery of additional diversions costs if this is required as we deliver net zero, whilst also allowing for customers to be reimbursed should outturn costs be lower than our forecast. This will ensure that we do not make an automatic profit or loss for reasons beyond its control, which would weaken our accountability for delivering services efficiently. The re-opener will incentivise us to manage Wayleave terminations in the best interests of consumers, recognising that agreeing a diversion can often be the most cost-effective way to resolve terminations (as opposed to the pursuit of a Necessary Wayleave or Compulsory Purchase, which can involve protracted negotiations and legal proceedings).

We have carefully considered the scope of the proposed re-opener, to ensure that it truly captures costs which are outside our control and challenging to predict. As a result, we have targeted our re-opener specifically towards physical diversion works, excluding costs associated with compensating IA claims. As noted above, we have taken this decision based on evidence that diversion works are harder to predict, with greater year-on-year volatility due partly to the smaller volumes and often high unit costs involved. In the absence of a re-opener, there would be a greater risk of customers overpaying for diversions through their baseline RIIO-ED2 bills, and our proposals will encourage an efficient view of baseline costs which minimises this risk.

g. Drawbacks of the proposed mechanism and mitigations

We acknowledge that our proposed re-opener could increase bill volatility for consumers at RIIO-ED2, especially if it is triggered multiple times, potentially leading to bill adjustments in both directions during the RIIO-ED2 period. This is a disadvantage of using a re-opener rather than a single end-of-period adjustment, which we are proposing for IA compensation costs. We recognise that an end-of-period adjustment approach is a plausible alternative to a re-opener, and this approach should be adopted for diversions costs (in common with IA compensation costs) if our proposed re-opener is not approved. The bill volatility impact of our re-opener is reduced partly through the materiality thresholds we are proposing, which ensure that bill adjustments can only be sought where there are material cost variances.

We also see several broader advantages of our re-opener over an end-of-period adjustment mechanism (for diversions costs). Firstly, our re-opener ensures that cost recovery is better aligned to cost incidence from a timing perspective, with current customers sharing in upward or downward cost adjustments rather than these adjustments being passed onto future customers at ED3.

This is particularly significant for cost variances which arise early in RIIO-ED2. Secondly, our re-opener arguably provides greater protection for consumers, with us only able to apply for additional funding when the materiality threshold is exceeded, and Ofgem having greater discretion over any adjustments to allowances. Whilst an end-of-period adjustment would still allow Ofgem to assess the efficiency of additional costs incurred, it is likely that a re-opener process will involve a more detailed examination of cost efficiency, which is in consumers' interests.

h. Value for money for consumers

We consider that our proposed re-opener offers strong value for money for consumers. As noted above, the re-opener will incentivise us to manage Wayleave terminations in the best interests of consumers, recognising that agreeing a diversion can often be the most cost-effective way to resolve terminations (as opposed to the pursuit of a Necessary Wayleave or Compulsory Purchase, which can involve protracted negotiations and legal proceedings). We will continue to pursue avoidance of Wayleave terminations through negotiation and voluntary land access settlements wherever possible, but the re-opener gives us the flexibility required to undertake timely diversions where this is the most cost-effective solution.

Additionally, we would emphasise that our proposed re-opener does not weaken the broader incentive for us to pursue Easement (Servitude) agreements over Wayleave agreements, thereby simplifying land access arrangements and reducing the need for diversion works. This is a core part of our land management strategy and will ultimately reduce bills for future customers.

6.2 Shetland

a. Issues and risks that the proposed mechanism addresses

As part of its licence, SHEPD manages the supply of electricity to the population of Shetland.

Shetland is not currently connected to UK mainland transmission network and must therefore generate its own electricity supply. Its primary generation source is Lerwick Power Station (LPS), with backup capacity available through a Power Purchase Agreement (PPA) with Sullom Voe Terminal (SVT), and both of these power stations are fossil fuel powered. The costs of maintaining these supply sources fluctuates year-on-year, due to factors outside of SHEPD's direct control. There is also a contribution to supply from island renewables, enabled by the island Active Network Management (ANM) scheme.

In ED1, the costs of SHEPD's activity in Shetland have been funded through a combination of defined totex allowances, re-opener UMs applicable to all of the totex allowances, and direct pass-through of some costs. For example, totex allowances and re-openers have been applied to LPS capital and operating costs (excluding fuel costs) and the SVT PPA, whilst fuel costs for LPS (and contingency generation) plus Environmental Permit costs have been subject to pass-through.

Shetland's electricity costs and wider activities on Shetland associated with securing an enduring solution are currently funded through the Extended Interim Energy Solution, which was decided by Ofgem in 2018.[12] This includes re-openers applicable to the totex allowances, which can only be triggered at the end of the ED1 period.

The current allocation of pass-through mechanisms and re-openers reflects the relative degree of SHEPD control over outturn cost. For costs subject to pass-through, Ofgem agrees that while SHEPD should manage its activities efficiently, it ultimately has no control over the prices paid, which are determined by the broader market and regulations. For costs which are subject to totex allowances and re-openers, Ofgem considers that SHEPD should be incentivised to manage costs efficiently, whilst also recognising that additional funding may be required for reasons beyond SHEPD control (reflecting the variable costs of providing security of supply for Shetland customers).

Over ED1, SHEPD has worked closely with Ofgem to develop a long-term supply solution for Shetland. Ofgem has now approved the development of a new 600MW HVDC transmission link connecting Shetland to the mainland electricity network in Great Britain, and the project has recently entered the construction phase. The new transmission link will provide SHEPD customers with an enduring supply solution, substantially reducing Shetland's reliance on remote fossil fuel generation and associated emissions. On this basis, Ofgem has also approved SHEPD's proposal to contribute towards the transmission link. In addition to supplying the distribution system, the new transmission link will enable the connection and export of a significant amount of renewable generation.

The link itself will be connected to Shetland's electricity distribution system through the development of a new grid supply point. The distribution connection to the transmission link is expected to become operational in November 2024, when the contribution is expected to be made.

The four re-openers sought by SHEPD are mapped against the four areas of cost that SHEPD expects to incur in ED2 in its delivery of the enduring solution, as set out below.

Existing solution extension costs

As the grid supply point will not be available until late 2024, the existing interim supply arrangements will continue until that point. This incorporates LPS operating in full duty with the existing 8MW battery, supply from SVT or an equivalent replacement, and the Shetland ANM scheme. The uncertainties associated with these costs which were identified and for which re-openers have been provided in ED1, will remain relevant in the first few years of RIIO-ED2 until the enduring solution is in place. The first re-opener, applicable to the Shetland Extension Fixed Energy Costs allowance (or its ED2 equivalent) will provide an opportunity to recover costs associated with delays to the enduring solution driven by cost changes and wider delays outside of our control. It is possible that, for example, the transmission development is delayed, meaning that we require to run existing, more expensive arrangements on for longer. At this stage in ED2 we may also be liable for payments to standby / blackout avoidance service providers, whose equipment has been implemented to deliver standby arrangements. It is also possible that there could be demand increases on the system which drive the need to procure additional equipment or services to meet demand.

[12] https://www.ofgem.gov.uk/system/files/docs/2018/06/decision_on_shetland_interim_solution_-_final_1.pdf

Process to implement enduring solution

SHEPD has undertaken procurement and assessment processes during ED1 to identify and implement an enduring solution for Shetland, as required under licence (CRC 2Q). The current iteration of this process will continue until the enduring solution is in place, expected by late 2024. It is possible that this process will take longer or change focus for reasons outside of our control, which could drive cost changes. In recognition of such uncertainties, Ofgem has provided re-openers associated with totex allowances for these processes in ED1, and we seek a replicated arrangement for ED2.

Link contribution

Since SHEPD customers will benefit from the supply from the transmission link, SHEPD will make a financial contribution to the capital cost. The exact size of the SHEPD contribution remains uncertain and will depend on the final cost of the transmission link, and on a forthcoming Ofgem decision determining how it is calculated. Ofgem may decide that the SHEPD contribution is based on the estimated final capital cost (SHET's allowance for the link defined at Project Assessment), in which case the SHEPD contribution will be known prior to project completion. Alternatively, Ofgem may decide that the SHEPD contribution is based on outturn capital cost, in which case the contribution will be determined through a pre-agreed formula once the project is completed.

In the case of the former situation, we consider that an adjustment will not be required, as the contribution value will be known before Final Determinations and can be incorporated into licence, the PCFH and PCFM, and RIGs as required as part of the ED2 business plan process. However, if Ofgem decides to base the contribution on the transmission link outturn capital cost (as opposed to estimated cost based, for example, on the Project Assessment allowance value) then an adjustment will be required to reflect the difference between the estimated contribution value when SHEPD's opening ED2 position is defined, and the actual contribution value when the final link cost is known.

Standby costs

In addition to the uncertainty over SHEPD's contribution to the new transmission link, there is also uncertainty over the costs of standby supply arrangements to be adopted once the new link becomes operational. These standby arrangements will ensure continued electricity supply for the Shetland population should there be a power outage affecting the transmission system. SHEPD has assessed a range of possible options for the standby solution and has recommended retaining Lerwick Power Station (LPS) in a standby capacity on the basis of this technical and cost-benefit analysis. As part of the standby solution as a whole SHEPD will be required to purchase blackout avoidance equipment and services from the market.

Even if LPS is retained, as is recommended, future plant upgrades could be required to reduce its carbon footprint and deliver environmentally sustainable standby capacity. While the standby arrangements will definitively be required to run to cover planned outages for around 4 days per year, for monthly testing, and any other planned or unplanned outages, there is inherent uncertainty in the extent to which the standby arrangements will be used, and there is also an element of uncertainty around when the standby arrangements will commence, given the dependency on the transmission link development. The outage regime is captured in Section 3.4 of the Shetland EJP and anticipates 4 days a year running for a 'regular' maintenance year, 14 days every 7 years, and 3 months every 20 years for planned outages.

Forced outage predictions are also set out, with an overall combined planned and unplanned outage prediction of 3 events and an average of 18 days per year running time. SSEND's cost estimate for LPS running in standby mode for ED2 is based on the assumption of 4 days of running for 'regular' maintenance year planned outages (plus once a month engine testing) only, protecting customers from the inclusion of uncertain additional costs. Similarly, while SHEPD expects to incur standing monthly Availability charges levied by blackout avoidance service providers in return for keeping this service and associated equipment ready to use (and to allow them to recoup their investment), it is unclear how often blackout avoidance services will be utilised.

There is uncertainty around the need for, and scope and nature of, the proposed AC chopper (or alternative) which would help to ensure a smooth disconnection of the distribution and transmission systems when transmission outages occur (reflecting on the substantial volumes of wind which may be operating at the time). There are also uncertainties around SHEPD costs to integrate with the transmission ANM scheme, which is expected to be required to manage export from the distribution system onto the transmission system. SHEPD's cost estimates for the future standby arrangements are built on a 'base case' view of demand, however it is also possible that more customers will seek demand connections during the period. If this occurs, SHEPD will require to invest more in standby arrangements to meet this demand.

Given the uncertainties listed above, we are proposing a suite of UMs which cover costs linked to the current Shetland supply solution, and the Shetland future supply solution should this become operational during RIIO-ED2. By 'future supply solution' we refer collectively to the new transmission link and the future standby supply solution.

In the event that an alternative solution to LPS is required within RIIO-ED2 or ED3, costs will arise for decommissioning LPS, staff redundancy, and procuring alternative standby supply capacity from the market. We note that historically Ofgem intended to provide SHEPD with a UM for decommissioning and redundancy (see term "Lerwick Power Station Decommissioning Costs (UCLPSDC)" and "Lerwick Power Station Redundancy Costs (UCLPSRC)" in Ofgem's 2017 **Consultation on the cost of the new energy solution for Shetland**). Given the low likelihood of LPS decommissioning occurring before 2028, we have not currently built these aspects into our suite of UMs; however, if this is required, we will engage with Ofgem for provision of appropriate new mechanisms for these costs and associated with new standby provisions.

b. The design of the proposed mechanisms

Our proposed Shetland UMs are set out in Table 6.2 and the design is discussed in more detail below.

Table 6.2: Summary of proposed Shetland UMs

Re-openers	Re-opener timing	Estimated uncertainty range	Trigger threshold	Notes
1. Extended interim arrangements	Propose available any year from 2024/25 inclusive	-£0m > +£6m if enduring solution 4 months late to March 2025 (up to +£22m if 1 year late, not reflected in range)	10% symmetrical	
2. Enduring solution process costs		-£0.25k > + £0.25m		
3. Contribution		Not known – outside of SHEPD control as driven by SHET costs and Ofgem decisions	Zero. symmetrical – automatic adjustment if link cost changes	If Ofgem determine contribution is based on SHET allowance at Project Assessment, no adjustment required.
4. Enduring standby costs		- £13m > + £14m (if high demand)		

Existing solution extension costs

Until Shetland's future supply solution becomes operational, we are proposing to continue the funding arrangements currently applicable to Shetland under the Extended Interim Energy Solution arrangements. This includes an ex-ante allowance, a pass-through mechanism and a re-opener which apply to the ex-ante allowances. In our BPDT we have proposed this is to be continued in the form of the Shetland Extension Fixed Energy Costs allowance.

Process to implement enduring solution

SHEPD has utilised the Competitive Process Costs allowance (CPC, early ED1) and the Shetland Enduring Solution Process Costs allowance (2019/20-2022/23) to cover the administrative costs to identify and implement an enduring solution. Each of these allowances included the provision of re-openers to manage uncertain costs. We propose an extension of these arrangements for ED2, which in our BPDT we have proposed is continued in the form of the Shetland Enduring Solution Process Costs allowance.

We propose that the RIIO-ED2 continuation of these re-openers will have annual application windows, meaning that SHEPD will have the opportunity to apply for additional funding each year until the future supply solution becomes operational. In keeping with the Extended Interim Energy Solution arrangements, we propose that the materiality thresholds for these re-openers are set at 10% of the associated individual totex allowances, with both upward and downward allowance adjustments being subject to these materiality thresholds. The exception to this is the Shetland Extension Battery Costs allowance, which will have a 10% materiality threshold for upward allowance adjustments but a 0% materiality threshold for downward allowance adjustments (this is also in keeping with the Extended Interim Energy Solution).

Link contribution as noted above SHEPD will be allowed to trigger this re-opener **only** if Ofgem decides to base the contribution on the transmission link outturn capital cost (as opposed to estimated capital cost). We propose that SHEPD should have the flexibility to trigger this re-opener at the appropriate time (reflecting uncertainty over the completion date of the link and grid supply point), with annual application windows available. We anticipate that Ofgem's final decision on the contribution methodology will be provided as part of the Shetland link Project Assessment process, meaning that if Ofgem decides to base the contribution on estimated capital cost, then this re-opener will not be needed in our final RIIO-ED2 business plan. We also note that the contribution to the transmission link will likely be a RAV transfer and so not an adjustment on baseline Totex, and for this reason the cost materiality has not been included in our UM range.

We propose that this re-opener should not have an associated materiality threshold. This is because the transmission link contribution partly depends on an Ofgem decision, and we consider that UMs of this kind (where we are waiting on Ofgem decisions) should not have a materiality threshold because if the decision had been made earlier, we would have the opportunity to recover costs in full. Moreover, the transmission link contribution formula is designed to reflect the proportional benefits that SHEPD customers will derive from the new transmission link and has already been approved by Ofgem, and if it is agreed that the contribution is based on outturn capital costs, the value of any adjustment will be calculated mechanistically based on the methodology.

Standby costs

This re-opener will provide for a range of uncertainties associated with the costs of delivering Shetland's future standby supply arrangements, as highlighted above. We propose that this re-opener will have annual application windows, commencing in 2024/25. Again, in keeping with the Extended Interim Energy Solution arrangements, we propose that the materiality threshold for this re-opener is set at 10% of the associated Totex allowance, with both upward and downward allowance adjustments being subject to these materiality thresholds.

Further to our introductory note above on the spring 2022 update to Ofgem on standby costs, we will have more clarity on standby and blackout avoidance costs and contractual arrangements at that time, and propose we also engage with Ofgem on refinement to the re-opener for the Shetland Standby Fixed Energy Costs at that time.

c. Ownership of risks under the mechanism

Under Shetland's current funding arrangements, some costs are passed on to consumers in their entirety via pass-through mechanisms, meaning that consumers bear the risk of any cost fluctuations. As noted above, this includes fuel costs for LPS (and contingency generation) plus Environmental Permit and carbon costs. This balance of risk is appropriate because these costs are transparent, unavoidable and not in SHEPD's direct control (as Ofgem agreed at ED1).

For the proposed re-openers applicable to Shetland's current supply solution and Shetland's future standby supply arrangements, risks will be shared between SHEPD and consumers. SHEPD will bear the risk of small cost fluctuations which do not exceed the materiality threshold, as well as the risk of re-opener applications being rejected by Ofgem. Consumers will bear the risk of providing additional funding should SHEPD make a successful re-opener application.

This balance of risk is appropriate because it will incentivise SHEPD to manage the impacts of smaller cost fluctuations, whilst also ensuring that consumers contribute additional funding should this be demonstrably required (subject to Ofgem's approval). All of the re-openers are two-sided, and consumers will therefore be reimbursed should outturn costs be materially lower than the baseline Totex allowance.

For the proposed re-opener applicable to the SHEPD transmission link contribution, consumers will bear the risk of all cost fluctuations because we are not proposing to apply a materiality threshold. This balance of risk is appropriate because the SHEPD contribution methodology is partly driven by the transmission link cost and partly by the principle that SHEPD and its customers should pay their fair share of this cost, both approved separately by Ofgem. Should Ofgem decide to base the contribution on outturn costs, then the final contribution made by SHEPD will reflect the estimated proportional value of the transmission link to SHEPD customers (relative to other link beneficiaries). It is important to note that this re-opener will be two-sided, meaning that if the contribution is tied to outturn cost, funding will be returned to consumers should outturn capital costs be lower than expected.

d. Materiality of issue

Given we are proposing several UMs, we estimate materiality separately for each mechanism.

We have not estimated materiality for pass-through of current supply costs, because the adjustment of cost allowances is automatic. For the re-openers applicable to Shetland's current supply solution, we estimate a cost uncertainty range of -£0m to +£6.3m prior to construction of the transmission link. Our range is derived using outturn and projected ED1 cost data, and it reflects the expectation that Shetland will transition to its future supply solution from November 2024 onwards.

For the SHEPD contribution to the new transmission link, the cost uncertainty range is unknown relative to the baseline of £0 - there is no provision for the transmission link contribution within the baseline RIIO-ED2 plan, as this is being accounted for separately through a RAV transfer.

For the cost of delivering Shetland's future standby supply arrangements, we estimate a cost uncertainty range of -£12.7m to +£14m. In the low-cost scenario, SHEPD incurs costs from procuring and operating blackout avoidance equipment (including a battery and synchronous condenser), but no additional equipment is required to manage the impact of transmission-connected wind on the distribution system, no further costs are incurred to integrate the distribution and transmission systems, and no further equipment or services are needed to meet additional demand on the distribution system. By contrast, in the baseline and upper cost scenarios SHEPD incurs additional costs from procuring and operating an AC chopper to provide protection against forced transmission outages and, in the upper cost scenarios, from procuring additional equipment and services to meet demand and / or to integrate with the transmission ANM system.

e. Frequency and probability of issue

For the current supply costs which are subject to pass-through, the adjustment of SHEPD cost allowances will be automatic and will occur in every year of RIIO-ED2.

For the current supply costs which are subject to a re-opener, we anticipate that material cost variances (requiring the re-opener to be triggered) could occur at least once during RIIO-ED2, but they are very unlikely to arise in every applicable year. If the new supply solution is available from late 2024 onwards as contracted (with the current supply costs re-opener automatically expiring when the new solution becomes operational), there may be a relatively low likelihood of the interim supply costs re-opener being triggered during RIIO-ED2.

For the enduring solution process costs, again if the new supply solution is in place from late 2024, there may be a relatively low likelihood of the associated re-opener being triggered during RIIO-ED2.

For the SHEPD contribution to the new transmission link, there will only be an option to trigger the associated re-opener once. We forecast there is a medium probability that the re-opener will need to be triggered over RIIO-ED2 (noting that use of the re-opener is dependent both on how Ofgem will set the SHEPD contribution, and the outturn construction cost of the link).

For the cost of delivering Shetland's future standby supply arrangements, we anticipate that the re-opener is fairly likely to be used, because there is a high probability of fixed set-up costs for the new standby solution which is subject to the range of uncertainties set out in this section.

f. Justifications for the proposed mechanism

The UMs introduced for ED1 have proven effective in managing cost uncertainties in Shetland, and we consider that the current pass-through and re-opener mechanisms should be retained until the future supply solution becomes operational. It is right for SHEPD to pass costs through to the consumer where it has no direct control over the price paid, including for LPS fuel and Environmental Permit costs. For other costs linked to the current supply solution, and for the process to implement the solution, the re-opener with its materiality threshold allows for risk to be shared appropriately between SHEPD and its customers.

Looking to the future, SHEPD faces reasonable uncertainties over the future costs of Shetland's electricity supply. It cannot directly influence the cost or timing of delivery of the new transmission link, which will be heavily influenced by Ofgem decisions on the contribution methodology and a range of external factors, including those impacting the delivery date, and we consider that SHEPD customers should share the cost of a long-term supply solution which will significantly benefit them financially and environmentally.

Similarly, the costs of the future standby solution will reflect customers' energy needs and the efficient costs of security of supply. Our proposed re-opener will provide SHEPD with the flexibility needed to develop the best long-term standby solution for Shetland, taking account of future capacity requirements and the need to support the net zero transition.

g. Drawbacks of the proposed mechanism and mitigations

Given that we are proposing several UMs, there is a risk that they could collectively create bill volatility for customers over RIIO-ED2, as a result of multiple allowance adjustments (noting that Shetland costs are subject to recovery via the Hydro Benefit Replacement Scheme, from GB consumers). There is a small probability that the outturn cost of the new transmission link could be higher than planned, which contributes towards this risk.

An alternative approach would be to use an end-of-period adjustment for the costs of Shetland's supply arrangements, including the SHEPD transmission link contribution and the new Shetland standby solution. However, this approach would not eliminate bill volatility for SHEPD customers, because there would still be a need to transition away from the baseline allowances provided for Shetland's current supply solution. Moreover, this approach could significantly delay the recovery of transmission link contribution costs, resulting in future consumers paying for a supply solution long after it has begun to benefit current customers.

To ensure transparency and best align current customer bills with current costs, we consider that our proposed suite of UMs should be used rather than an end-of-period adjustment approach. The bill volatility impacts of our UMs can be reduced through using re-opener materiality thresholds, which we are proposing for most of our re-openers.

h. Value for money for consumers

Our proposed UMs deliver value for consumers in several ways.

Firstly, our proposed mechanisms are two-sided, allowing for consumers to be reimbursed through pass-through and/or re-openers should outturn costs be lower than expected. This ensures that SHEPD will not profit automatically from cost reductions, where these happen for reasons outside SHEPD control.

Secondly, the new transmission link (and the wider transition to Shetland's future supply solution) will substantially benefit current and future SHEPD customers, as well as onshore renewable generators operating in the region, all of whom will have a long-term connection to the mainland electricity network. The normalised costs of supplying Shetland's electricity are currently much higher than the UK average, and the new transmission link will result in significantly lower bills for GB customers (who will subsidise Shetland electricity costs from April 2021). The new arrangements will also simplify regulatory arrangements and reduce bill volatility for customers, which is expected to reduce the need for Shetland UMs at ED3 and beyond. Given these clear financial benefits, we think it is right for customers to support adjustments for the outturn cost of the link should Ofgem set the contribution methodology on this basis.

Thirdly, the new transmission link will bring major environmental benefits to Shetland residents and the broader SHEPD customer base, sharply reducing the need for diesel-powered generation and supporting future renewable energy generation. Our proposed re-openers will allow SHEPD the flexibility required to develop a sustainable supply solution which achieves these goals, incorporating the necessary standby capacity.

6.3 Subsea Cables

a. Issues and risks that the proposed mechanism addresses

We operate 128 subsea cables on its UK distribution network, the vast majority (110) of which are in the SHEPD licence area although there are 18 subsea cables in the SEPD licence area too, including connections to the Isle of Wight. These cables play a critical role in connecting Scotland's Island communities to the network, providing power supplies from the mainland to 59 inhabited Scottish islands. This helps to provide security of supply for consumers, whilst also allowing island-based renewable generators to supply the broader UK population, supporting the transition to net zero.

The age profile of our subsea cables varies, and we therefore have an ongoing programme of cable inspection works which aims to proactively identify cable damage and assess the need for remedial works. Where appropriate, we conduct proactive replacement works (as well as repair and maintenance activities) to reduce the risk of future cable faults and power outages. This approach recognises that subsea cable faults can be highly detrimental to island communities, interrupting power supplies and requiring the use of remote backup generation. An effective proactive approach to cable inspection and remedial works reduces the occurrence of future faults and therefore the need for reactive cable repair or replacement.

Our RIIO-ED2 business plan therefore places emphasis on conducting proactive replacement works, recognising that this is more efficient and significantly less disruptive than relying on reactive replacement works to address cable damage. We are proposing a programme of specific proactive replacement works as part of our business plan, with the total value of these works being approximately £134m. This consists only of named projects where a clear needs case has already been identified for proactive work, which will substantially reduce the risk of future faults. Alongside this, our baseline plan incorporates inspection activities worth £16m, and general cable repair and maintenance activities worth £13m. Our proposed programme of enhanced inspections will allow us to identify any further cables requiring intervention.

However, we cannot eliminate the need for additional cable reactive works, and there is significant uncertainty over the volume of this work and therefore the costs incurred at RIIO-ED2. Many of the waterways crossed by our subsea cables have volatile weather conditions, and they are also busy maritime routes, with extensive marine traffic. These factors are beyond our direct control and an important driver of the cost uncertainty we face.

When reactive work is required, the costs of this work can be substantial, with the potential for significant premiums compared to proactive replacement work. This reflects the need to secure the required equipment and personnel for reactive work at short notice (including hiring vessels), as well as costs associated with compensating remote backup generators whilst the primary supply is restored. The ED1 period has seen several cable faults occur on our network, requiring substantial reactive works. Whilst we have historic data on the costs of reactive replacement works, which gives us a view of average unit costs, there remains significant uncertainty over the volumes of cable faults (and therefore reactive replacement works) at RIIO-ED2.

Aside from the replacement or repair of active cables, a further key aspect of the cost uncertainty regarding subsea cables concerns future cable decommissioning requirements. Marine Scotland is responsible for the integrated management of Scotland's seas, and our subsea cable management activities in the SHEPD licence area must comply with Marine Scotland requirements. At RIIO-ED2, there is potential for Marine Scotland to tighten requirements around the decommissioning of cables which are no longer in active use. As part of the decommissioning process, Marine Scotland may require regular inspections and increased removal of these cables from the seabed, which could have a significant cost impact. There is also the potential for similar requirements to be introduced by the equivalent public authorities in the SEPD licence area.

b. The design of the proposed mechanism

Given the cost uncertainties specified above, we are proposing three UMs to provide flexible adjustment of cost allowances over RIIO-ED2. These mechanisms include:

- A volume driver to cover reactive replacement works required following cable faults in SHEPD and SEPD.
- We are additionally proposing a closely related re-opener to cover additional efficient costs associated with providing remote power generation (and backup power supply) for SHEPD communities following cable faults at distribution or transmission, where this is required.
- A re-opener to cover new cable decommissioning requirements initiated by Marine Scotland or the equivalent public authorities in England (which could include cable inspections and partial or full cable removals).

Although there is also uncertainty over the extent of reactive repair works required at RIIO-ED2, we are proposing to include a funding allocation for repair works (including general maintenance) in our RIIO-ED2 baseline plan. This proposal reflects the relatively limited materiality of cable repair activity compared to replacement and recognises the need to limit the number and scope of UMs, targeting them towards the areas of greatest cost uncertainty.

In this section, we outline the proposed design of each mechanism individually.

Reactive replacement volume driver design

Our proposed volume driver will cover reactive replacement works required across our subsea cable network. This mechanism will adjust cost allowances annually depending on the extent of cable faults requiring reactive cable replacement, as measured through the length of cable replaced.

We are proposing a single unit cost allowance (UCA) for the volume driver, of £[redacted] per km of reactive cable replacement (with no ability to use this volume driver for proactive works). This incorporates costs for the following sub-activities:

a. Cable laying

b. Cable protection

c. Third party soft costs

d. Survey costs

e. Inspection costs

f. Compensation costs

g. Other replacement works costs and

h. Vessel hire costs

To derive our proposed UCA, we have considered multiple potential designs and evaluated their accuracy using a historic dataset, which captures 23 reactive cable replacements conducted since 2002. The three UCA designs we analysed were:

- £ per km of cable replaced.
- £ per MW of capacity released.
- £ per MWkm (i.e. the product of cable length replaced and capacity released).

We used a combination of graphical analysis, regression modelling and Monte Carlo analysis to test each of these UCA designs against our historic dataset. Further detail on our analytical methodology and our findings is provided in Appendix A, but we summarise the approach followed below.

We first plotted the historic datapoints as shown in Figure 6.2 below, to assess how well each of these designs describe the relationship between cable magnitude and £m replacement costs (with the aim being to identify a clear statistical relationship).

Figure 6.2: Scatter plots with trendlines for: left) £m/km, centre) £m/MW and right) £m/MWkm

[redacted]

We then conducted regression modelling and Monte Carlo analysis to further test the predictive accuracy of our three UCA designs. The regression modelling formalised our graphical analysis, testing the statistical significance of the relationships in Figure 6.2. Our Monte Carlo analysis went a step further, by examining the difference between costs predicted by these regressions versus actual costs incurred (the 'cost gap'). For each of the three UCA designs considered, our Monte Carlo approach involved selecting a random combination of 3 or 5 cable replacement projects from our historical sample, calculating the combined cost gap and repeating this 10,000 times to derive a distribution of cost gaps for each UCA design. We then evaluated the relative performance of each UCA design by considering the mean cost gap across the 10,000 simulations (the closer to zero, the better) and the standard deviation across the 10,000 simulations (the smaller, the better).

Taking into account each of these analytical approaches, we found that the £ per km UCA design provides the most accurate measure of reactive replacement costs, and based on the historic data studied we are proposing a UCA of £[redacted]/km.

Remote generation re-opener design

Our proposed re-opener will cover the efficient costs of securing remote power generation to provide communities with backup power supply, specifically in the case of cable faults which lead to power outages. We will be able to trigger the re-opener only if we are required to undertake reactive repairs or replacement on a subsea cable which has faulted **and** the fault has resulted in a loss of power supply through the affected cable.

The re-opener will have the standard materiality threshold and annual application windows, in line with the annual application of our reactive replacement volume driver. We consider that a re-opener is the most appropriate design for this UM, as the costs of remote generation can fluctuate significantly depending on the location and severity of cable faults (as well as the supply areas requiring backup generation). It is not therefore appropriate to use a volume driver (as we are proposing for reactive replacement) in this case.

We do not consider that Ofgem should be able to trigger this mechanism, as there is no potential for downward allowance adjustment (only upward adjustment) and the use of the mechanism is not determined by Ofgem decisions. We consider that it is our sole responsibility to apply for funding adjustments where required, ensuring that we provide sufficient justification for the re-opener to be used.

Cable decommissioning re-opener design

Our proposed re-opener will cover changes to Marine Scotland requirements (or equivalent requirements in the SEPD licence area) governing the treatment of decommissioned cables, which could include (but will not necessarily be limited to):

- Inspection of decommissioned cables.
- Partial or full removal of decommissioned cables.

The re-opener will have the standard materiality threshold and annual application windows. The trigger for its use will be a defined change in requirements set by Marine Scotland (or the equivalent public authorities in England), formalised either through general legislative changes or specific legal instruction to us, for the treatment of decommissioned cables on either a cable-specific or network-wide basis. It will be our responsibility to demonstrate that the new requirements will require material additional funding (above the materiality threshold) to fulfil.

We consider that a re-opener mechanism is the best way to manage uncertainty, recognising that our decommissioning requirements have been limited to date, and also that there is considerable uncertainty over the direction and extent of future Marine Scotland requirements. We believe a re-opener design is beneficial for both ourselves and consumers as more accurate costs can be identified based on events during RIIO-ED2, with less risk ultimately placed on all parties.

We do not consider that Ofgem should be able to trigger this mechanism, as there is no potential for downward allowance adjustment (only upward adjustment) and the use of the mechanism is not determined by Ofgem decisions. We consider that it is our sole responsibility to apply for funding adjustments where required, ensuring that we provide sufficient justification for the re-opener to be used.

c. Ownership of risks under the mechanism

The ownership of risk for subsea cable damage and faults ultimately sits with both the network owner and customers, as subsea cables are often a single point of failure, and cable faults can therefore result in power outages and the potential need for remote backup generation. Risk is shared between parties here, in the sense that customers incur social and economic costs from the interruption of supply whilst the DNO must co-ordinate reactive repair or replacement works, typically at significant cost premia.

By conducting well-targeted proactive works as part of our baseline plan, we can substantially lower the probability of cable faults and thereby reduce the risks incurred by customers. Where funding is provided through baseline allowances, the majority of risks are borne by the DNO, with customers sharing in overspend or underspend (noting that this creates upside as well as downside risk).

This provides a clear rationale for the programme of proactive works (as well as enhanced inspections) included in our baseline plan.

Turning to our UM proposals themselves, our proposed volume driver for reactive replacement will also share risks between us and our customers. The volume uncertainty over reactive works will be borne by customers, who will contribute additional funding should this be required. We will bear the risk that outturn unit costs are higher than the agreed UCAs, which could arise if reactive cost premiums are higher than anticipated, although there is also the potential for outturn unit costs to be lower than the agreed UCAs. We consider that this balance of risk is appropriate, as the volume driver will provide strong incentives for us to deliver reactive replacement works efficiently, and customers will stand to benefit from timely completion. The use of a volume driver (which is relatively automatic) provides a credible commitment that we will invest as required to replace damaged cables and minimise disruption to our customers.

Our proposed re-opener for remote generation costs will share risks between us and our customers. It will be our responsibility to justify the need for additional funding to support remote backup generation in the event of a cable fault, with Ofgem being able to challenge our proposed costs. This offers greater customer protection than the volume driver for reactive replacement costs, and we consider that this is appropriate as the costs of remote generation can fluctuate significantly depending on the location and severity of cable faults, which increases the need for regulatory scrutiny. Equally, it is important that customers share the costs of managing and resolving unforeseen cable faults, as this reduces supply disruption and supports the timely completion of reactive repair or replacement works, all of which benefits customers.

For our proposed re-opener covering decommissioning costs, the risk lies predominantly with us as there is no guarantee that re-opener applications (and the need for additional funding) will be accepted by Ofgem, potentially resulting in unrecoverable costs. However, customers will also bear some risk that requirements will materially change over RIIO-ED2, potentially requiring substantial additional costs (especially if the new requirements apply across a large number of inactive cables). This could potentially increase not only the volume of works, but also the market prices of cable inspection and removal activities (which are typically reserved for active cables at present). We consider that this is a reasonable balance of risk, placing a clear requirement on us to justify the cost impacts of new requirements and make the case for additional funding. It is right that customers should bear some risk of additional costs, as Marine Scotland (and the equivalent public authorities in England) make decisions on behalf of the broader population which aim to protect the marine environment (bringing its own benefits to consumers).

d. Materiality of issue

We have separately estimated the cost uncertainty associated with each of our proposed UMs. Given the relatively limited extent of our cable network in the SEPD licence area, it has not been possible to reliably develop cost uncertainty ranges for SEPD due to limited historic cable fault incidence.

The cost uncertainty ranges presented below therefore relate to the SHEPD licence area, where the majority of our cable network is located.

For reactive replacement works, we have estimated a cost uncertainty range of £0 to £67m, relative to a baseline (for reactive replacement) of £0. We have calculated this range using historic data on cable fault rates. Based upon this historic data, we experience an average of 3.2 faults per year with 1.4 of these faults leading to repair work and 1.8 leading to replacement work. The upper end of our range (£67m) assumes that we continue to incur 1.8 faults per year requiring replacement throughout RIIO-ED2. This is an appropriate upper cost estimate because our proposed RIIO-ED2 baseline plan involves a much greater emphasis on proactive replacement than previous price controls, and we would expect this proactive work (together with responsive replacement) to reduce the need for reactive replacement at RIIO-ED2.

For remote generation, we have estimated a cost uncertainty range of £0 to £8.7m, relative to a baseline of £0 for additional remote generation costs in event of fault. We have calculated the upper end of our cost uncertainty range using our estimated expenditure on mobile and embedded generation tied to subsea cable fault response over the 2020-21 reporting year. The upper end of our range assumes that the costs incurred in 2020-21 will be repeated across all five years of RIIO-ED2. The £0 baseline reflects how our RIIO-ED2 plan does not include baseline costs for reactive (i.e. post-fault) replacement of subsea cables, and therefore there is no baseline provision for mobile and embedded generation tied to subsea cable fault response. It is important to note that our RIIO-ED2 plan does include baseline cost provision for remote generation capabilities more broadly (i.e. remote generation not tied to additional costs for subsea cable fault response).

For decommissioning costs, there is substantial uncertainty about the potential costs we could incur at RIIO-ED2. This is driven by several factors, including the unknown scope and strength of new decommissioning requirements, and the limited precedent (and historic cost base) for conducting such decommissioning works. Due to the challenges of projecting future costs in this area, we have not estimated a cost uncertainty range.

e. Frequency and probability of issue

The reactive replacement volume driver will involve automatic annual adjustments to cost allowances, and this is likely to be used regularly through RIIO-ED2 given that historic data indicates an average of 1.8 cable faults (requiring reactive replacement) per year. The extensive proactive work planned by us for RIIO-ED2 should reduce the likelihood of cable faults, but there remains significant potential for unforeseen events such as 3rd party damage which could create a need for repair or replacement works.

Similarly, the potential frequency of cable faults means that the remote generation re-opener could be used multiple times through RIIO-ED2, with the frequency of use depending on the materiality of the faults incurred (and the costs of remote backup generation).

The decommissioning re-opener will only be triggered should changes in decommissioning requirements push additional costs above the materiality threshold. We anticipate that there is a moderate probability of new requirements, but it is highly unlikely that requirements will materially change more than once over the RIIO-ED2 period (meaning that the chance of the re-opener being triggered multiple times is very low).

f. Justifications for the proposed mechanism

Taken collectively, our proposed UMs for reactive replacement together with the remote generation re-opener aim to ensure that cable damage is addressed promptly and efficiently.

Our proposed volume driver for reactive replacement recognises that cable faults cannot always be avoided and may occur for reasons beyond our control. Restoring subsea cable supplies quickly and cost-effectively is critical, as this minimises the negative impacts of disrupted power supplies and also importantly reduces the need for backup remote generation. Currently when faults do occur, diesel generators are often required to bring the remote areas back online and local renewable generators are disconnected as the network is down. The timely replacement of subsea cables is therefore vital not only for customer service, but also in supporting the net zero transition and minimising disruption to renewable generators in our island communities (which in turn impacts their profitability). Our volume driver will strongly incentivise us to respond with agility and efficiency when cable faults occur. This will be further supported by our remote generation re-opener, which will provide the flexibility needed to secure remote backup generation quickly and cost-effectively, thereby reducing customer disruption.

Our proposed re-opener for decommissioning costs reflects the substantial uncertainty we face over future cable decommissioning requirements, bearing in mind that we have not conducted many end-of-life inspections or removals of decommissioned cables to date.

The scope of any new requirements is unknown, creating significant uncertainty over their cost impact, especially because the changes could apply across selected high-risk cables or across our broader network. We consider that our re-opener provides the required protection should our decommissioning costs substantially increase (maintaining a clear financial distinction from our management of active cables), whilst recognising that these highly uncertain costs are not suitable for baseline funding.

g. Drawbacks of the proposed mechanism and mitigations

The volume driver proposed for reactive replacement could potentially be used as a back-up or insurance policy should we run out of baseline funding for proactive works. This drawback is mitigated partly by ensuring all cables that will be proactively managed and all that will be reactively managed are clearly identified in advance of the price control. This provides transparency over our intended activities and helps to ensure the volume driver will not be exploited or otherwise de-incentivise proactive work. This clear distinction of activities reinforces the strength of our baseline funding proposals (and the likelihood of securing a suitable funding package), thereby minimising the extent to which reactive replacement is seen as a backup option.

h. Value for money for consumers

Our proposed approach to subsea cable management provides value for money in several ways.

The proactive cable management approach proposed by us for RIIO-ED2 provides value for money for consumers as it reduces the average costs incurred from cable replacement activities. If a reactive-only approach was taken to large, high-risk cables then substantial premiums would be incurred due to the short notice required for vessel hire and cable manufacturing. These premiums drive the price of work up substantially, and therefore planned proactive work is typically more cost-effective than reactive work. Our baseline plan, together with our proposed volume driver for responsive replacement, will ensure that less emphasis is placed on reactive works than in previous price controls, driving improvements in cost efficiency and reductions in cable faults.

Our approach additionally provides broader value to customers, from a social, economic and environmental perspective. Our proposals will strongly incentivise the avoidance of cable faults and timely fault response, thereby reducing the occurrence and duration of power outages and remote backup generation. This will minimise disruption to customers from our island communities, supporting local economies and reducing harms to vulnerable consumers. By ensuring that renewable generators can stay connected to the mainland grid and reducing the need for diesel-powered island generation, our proposals will also reduce the environmental footprint of our island communities and support the transition to net zero, ultimately benefiting consumers right across our licence areas.

6.5 Distributed Generation Monitoring

a. Issues and risks that the proposed mechanism addresses

In August 2020, Ofgem published a call for evidence on visibility of distributed generation (DG) connected to the GB distribution network. This followed an investigation into the 9 August 2019 power outage.

Ofgem published a document[13] on 26 February 2021 setting out its findings on its call for evidence, and next steps to improve DG visibility.

Ofgem summarised its findings stating that the GB Electricity System Operator (ESO) and DNOs are likely to be the principal data users and beneficiaries, that use cases for DG visibility data are poorly defined and that no cost benefit analyses for improving DG visibility have been undertaken. The costs to establish full visibility of distributed generation on our networks are significant and we agree with Ofgem that the use cases are not yet clear.

The following timeline was set between Ofgem and the ENA earlier in 2021:

- Defining the use cases and frequency of occurrence, and number of generators affected thereof, for DG visibility and monitoring for the ESO and DNOs - by May 2021.

[13] Next steps on visibility of distributed generation connected to the GB distribution networks

- Defining functional specification of uses cases - by July 2021.
- Derive a cost-benefit analysis framework and undertake this for DG visibility and monitoring - by December 2021.

Beyond 2021, further steps will be required to consider:

- The most appropriate DG visibility required against each use case.
- Whether DG visibility equipment should be installed on existing or newly connected DG.
- Policy options for the governance and cost of improving DG visibility.

As it stands, the timelines set out by Ofgem will make it impossible for network companies to develop detailed proposals for DG monitoring in baseline plans, since all the above steps are required to be completed as a prerequisite, and this will certainly not happen before December 2021. As such, we have not included any costs for enhancing visibility of existing distributed generation in our baseline plan.

There remains a significant possibility that the conclusions of Ofgem's review of DG monitoring will impose significant burdens on DNOs, and if this were to occur it would likely be during RIIO-ED2. In this case, we would not have sufficient allowance in our baseline plan to cover the associated costs, and we are thus proposing an UM to cope with this possibility.

b. The design of the proposed mechanism

The proposed mechanism is a re-opener, with the standard materiality threshold (1% of annual allowed base revenue) and annual application windows.

The re-opener will be triggered by decisions by Ofgem or related bodies that there is a needs case for a material amount of DG monitoring, and that the cost burden of such monitoring should fall on DNOs such as us.

c. Ownership of risks under the mechanism

The risks associated with this mechanism are owned mostly by our consumers, since they will bear the full cost of DG monitoring during RIIO-ED2 should they be required and material. However, any smaller costs under the materiality threshold related to this issue will be absorbed by our business.

This apportionment of risk is appropriate since the decision to install DG monitoring and impose the cost on DNOs will likely fall outside our control. The mechanism will only be triggered should Ofgem's extensive review result in identification of a needs case, and thus consumers can be confident that, overall, they will benefit despite temporary bill impacts. The alternative of including this funding as part of our baseline plan would reduce risk to consumers, but there is a possibility that DG monitoring costs will not be imposed on DNOs, as well as the likely inaccuracy of any baseline costs due to the exact nature of DG monitoring still being unclear.

d. Materiality of issue

We have considered the maximum possible cost of increasing DG monitoring across our network as a result of policy decisions described above. Combining these across our Capital Expenditure (CapEx) and Operating Expenditure (OpEx) categories and various site voltages, this gives an upper bound of £24.1m for SEPD and £16.7m for SHEPD. As there is no baseline spend associated with this uncertainty, the range relative to baseline is £0 to +£24.1m and £0 to +£16.7m for SEPD and SHEPD respectively.

e. Frequency and probability of issue

This mechanism will only be triggered once, since it is predicated on a specific event that will likely only occur once at most over RIIO-ED2 (based around a specific Ofgem policy decision). Despite this, the mechanism has an annual application window to ensure flexibility over timing of any re-opener application.

The probability distribution of the potential outcomes of Ofgem's DG monitoring is difficult to forecast. Our current expectation is that there is a medium probability of a need for this mechanism to be triggered.

f. Justifications for the proposed mechanism

This mechanism will only be triggered should the DG monitoring review process, which is being led by Ofgem, concludes that a material amount of DG monitoring investment is needed and net beneficial to consumers, and that these costs should be covered by DNOs. The need for an UM in this area is entirely due to timing factors completely outside our control – had this review happened earlier, then any need for investment could have been included in our baseline plan.

This timing problem is similar to the Access SCR issue discussed in the following sub-section, for which Ofgem itself suggested an UM may be necessary. As Ofgem already acknowledges the justifications in this area, we consider that this UM would be just as merited.

g. Drawbacks of the proposed mechanism and mitigations

A potential drawback of funding this area through UM in that it could leave consumers exposed to the types of issue seen in the 9 August 2019 power cut until an appropriate plan of investment can be scoped and justified through a re-opener application. However, given the need to ensure a full needs case in this area to determine the course of action providing most value to consumers, it is not possible for our industry to provide certainty on this issue before the start of RIIO-ED2. An UM provides the best alternative to this.

h. Value for money for consumers

The value for money provided by DG monitoring itself will be determined by the extensive cost-benefit analysis being undertaken by Ofgem and the ENA over the coming year. The UM itself provides value be ensuring that, should this review determine that investment in DG monitoring would benefit consumers on balance, DNOs such as us will be able to access funding to finance these investments.

6.6 Polychlorinated Biphenyls replacement

a. Issues and risks that the proposed mechanism addresses

The European Commission introduced a new Regulation on Persistent Organic Pollutants (POPs) (Regulation (EU) 2019/1021 of the European Parliament and of the Council of 20 June 2019 on persistent organic pollutants (recast)). Appendix 1 to the Regulation states that:

"*Member States shall identify and remove from use equipment (e.g. transformers, capacitors or other receptacles containing liquid stocks) containing more than 0,005 % Polychlorinated Biphenyls (PCBs)*[14] *and volumes greater than 0,05 dm*^{3}*, as soon as possible but no later than 31 December 2025*".

Environment Agency (EA) guidance applies the assumption that transformers are PCB contaminated if manufactured before 1987 unless it is certain that they are uncontaminated e.g. if they have been tested to show that they contain 50ppm or less of PCBs. The effect of these Regulations and the EA's guidance is that DNOs will have to test all ground mounted transformers manufactured before 1987 for PCBs and remove those which are contaminated. As Pole Mounted Transformers cannot be sampled and tested on site, all pre-1987 units will have to be replaced unless a method can be found to determine their PCB content.

It is recognised industry wide that DNOs generally have limited visibility of the prevalence of PCB on their network, as this was not information previously required to be logged or monitored. We like other DNOs have established an internal asset data task force to understand prevalence and requirements for asset replacement. Data is being provided on an ongoing basis through sampling, but full visibility of work required will not be known until into the RIIO-ED2 period. We are in discussion with Ofgem, alongside peer DNOs, through the ENA on determining the provision of additional funding with the ED1 period for removal of a portion of these assets containing PCBs, given this was unknown and not accounted for in setting the current price control period. However, this will not account for all asset replacement given ongoing data gathering, and it is anticipated significant of the funding will be required through RIIO-ED2.

Our analysis has sought to identify volumes where we have confidence that costs will be incurred during either in the RIIO-ED1 period, or the RIIO-ED2 period. Where we don't have confidence in quantum of assets to be replaced attempting to recover all RIIO-ED2 costs through the baseline places a greater risk on consumers as we have insufficient information from historical precedence to set a full ex-ante allowance request with confidence. As such, the RIIO-ED2 UM will ensure funding is provided for those additional volume of asset replacements required for the volumes we are mandated to replace, and which have not already been funded via another source. Should funding for asset replacements during the RIIO-ED1 period not be approved ahead of time, the UM would also enable the recovery of such costs.

b. The design of the proposed mechanism

We propose the mechanism should be a volume driver and with a final review on volumes. Allowance for PCB replacements will be increased annually and automatically through a volume driver, at the agreed RIIO-ED2 unit rates for individual asset classes, based on a DNO's reported volume of assets replaced. It

[14] PCBs are a family of substances which are good electrical insulators used historically in electrical transformers and capacitors. They are chemically stable, fire resistant and don't easily generate a vapor.

would cover allowances for the volumes we are mandated to replace, and which have not already been funded via another source. We propose this arrangement remains in place until at least 2026[15] whereupon we should set out to Ofgem justification through a close out report, with independent verification, for the total volume of assets removed in accordance with meeting the legislative target. Ofgem would then have the right, but not the obligation, to adjust the total volumes of assets funded for removal via the volume driver, if evidenced that the total volumes exceed that which are required in order to comply with legal obligations. The final review we propose would only be triggered by Ofgem and would only be applicable to the volume of assets delivered and funded via the volume driver and not the unit cost of assets associated with replacement. The final review would only, if applied, be able to adjust the total volumes down from the total replacements declared by DNOs and standard materiality thresholds would apply.

The scope of the volume driver should cover all asset classes which contain PCBs as identified by DNOs in submission of the close out report and independently verified.

c. Ownership of risk under the mechanism

This mechanism is designed to reduce the risks related to PCB removal borne by both us and consumers. Consumers will bear the overall costs replacing assets containing PCBs to meet the legislative target and the volume uncertainty in the first three years of RIIO-ED2, since this will impact their bills. We will however look to minimise any fluctuations.

We should bear the cost risk associated with volumes of assets rejected by Ofgem as not justifiably replaced, upon review of the close out report. We believe by only allowing for a downward adjustment on total volumes this gives us incentive to efficiently phase the removal of PCB assets up until the legislative deadline and avoids excessive bill fluctuations.

Additionally, we will bear risks related to the unit cost allowance, albeit subject to the totex Incentive Mechanism. This represents a reasonable balance, since the volume of replacements is mostly determined by the results of the sampled data, whilst there is scope for our business to seek efficiencies on unit costs.

d. Materiality of issue

Our current evaluation of the Pole Mounted Transformers (PMT) that would need to be replaced has followed the approach developed for the ENA cohort model based on the testing we have done to date. Using this approach, we have been able to classify volumes of our PMT population into those that a) we know need replacing, b) we know don't need replacing, and c) where more testing is needed. Where we know volumes need replacing, we propose that the costs of these are recovered through the funding within RIIO-ED1 period (i.e. we replace as soon as possible) or within the baseline costs for RIIO-ED2. Where more testing is needed, we estimate that 50% of these may need replacing, but proposes that these volumes are treated by the UM. Tables 6.6 (a) and 6.6 (b) summarises our current view of the PMT volume split.

[15] This date should be subject to review pending any derogations provided by the Environment Agency or the Scottish Environment Protection Agency; but be no earlier than 2026.

Table 6.6 (a) – PMT volumes for replacement SHEPD

Vol (#)	RIIO-ED1 Accelerated 2021-2023	RIIO-ED2 Baseline 2023-25	RIIO- ED2 UM Volumes
PMT (mainly 11kV)	1,234	2,900	3,475
PMT (mainly 33kV)	55	129	196

Table 6.6 (b) – PMT volumes for replacement SEPD

Vol (#)	RIIO-ED1 Accelerated 2021-2023	RIIO-ED2 Baseline 2023-25	RIIO- ED2 UM Volumes
PMT (mainly 11kV)	2,213	5,136	1,532
PMT (mainly 33kV)	1	3	2

For Ground Mounted Transformers, we have adopted a similar approach although we have identified alternative solutions to replacement, through undertaking an oil change, resulting in a more efficient cost outcomes. Tables 6.6 (c) and (d) summarises our current view of the GMT volume split.

Table 6.6 (c) – GMT volumes for replacement SHEPD

	RIIO-ED1 Accelerated2021-2023	RIIO-ED2 Baseline 2023-25	RIIO-ED2 UM Volumes
GMT (Oil Change) (minimum)	45	59	0
GMT (Replacement for 11kv only) (minimum)	10	5	112

Table 6.6 (d) – GMT volumes for replacement SEPD

	RIIO-ED1 Accelerated2021-2023	RIIO-ED2 Baseline 2023-25	RIIO-ED2 UM Volumes
GMT (Oil Change) (minimum)	306	242	0
GMT (Replacement for 11kv only) (minimum)	103	4	212

In the RIIO-ED2 period we estimate a total cost uncertainty range of £37m (SEPD: £16.3m & SHEPD: £20.1m). This includes replacement and oil changes. The cost for GMT inspections is included within the baseline for RIIO-ED2 and accelerated funding for RIIO-ED1.

e. Frequency and probability of issue

The volume driver would be triggered annually upon receipt of our annual report of volume of assets taken off the network. The probability of using the volume driver would be near certain for the first three years of RIIO-ED2. The final review would only be used once at the discretion of Ofgem, should there be sufficient evidence that the total volumes funded for replacement through the volume driver were not justified.

f. Justifications for the proposed mechanism

The nature of the mechanisms is proposed due to the unique nature of the uncertainty faced and need for additional funding being recognised by Ofgem. There is little cost uncertainty in replacing the assets containing PCBs. The types of assets in question are common across the network and latest unit costs for these assets are included in our business plan submission. There is however a volume uncertainty linked to the outcome of ongoing asset data gathering activities which will extend into the RIIO-ED2 period. Given the need to deliver the total replacement requirements by the legislative target and the expected large volume of assets to be replaced simultaneously in the first three years of RIIO-ED2 we propose an automatic mechanism volume driver mechanism is applied. The automatic mechanism will ensure we deliver the timely replacement of assets in the short period available until the legislation comes into force. We propose volumes are adjusted annually upon production of an annual report by us on volumes replaced. We propose adjustment done at the unit rates agreed for the purpose of RIIO-ED2 for the applicable asset classes as this is not likely to materially change in the first three years of RIIO-ED2 following business plan commencement.

Automatic volume driver mechanisms however typically require a clear external trigger to justify the change in volumes being funded for. In the absence of this a suitable protection is required to ensure the volumes being replaced are justified by the network company. Whilst the requirement to replace the assets is clearly linked to a need set out in legislation, the total volume of the replacements up to 31st December 2025 is currently within our span of influence and is linked only to the ongoing internal asset data assessments of assets containing PCBs. This creates a risk to consumers with an automatic mechanism in that it potentially allows DNOs to trigger replacements without reference to an external trigger. To allow the benefits of the automatic mechanism to be realised whilst simultaneously protecting consumers and given the unique considerations of this uncertainty we propose a final review with the volume driver which would afford Ofgem the right, but not the obligation, to review the volumes of assets delivered in each year to ensure replacements are justified. We propose Ofgem only be allowed to trigger the final review once upon receipt of a PCB volumes close out report by us which will be independently verified. We are proposing this final review is unidirectional and can only act to adjust the total volume of assets replaced down from the level funded through the volume driver, if evidenced necessary by Ofgem. This mechanism enables us to ensure targets are achieved, without creating an incentive for us to over-invest PCB replacement.

g. Drawbacks of the proposed mechanism and mitigations

The two main alternatives to the proposed mechanism are the application of a re-opener rather than a volume driver, or no UM. The main drawback of a volume driver mechanism is the lack of external reference point on the volumes requiring automatic funding adjustment. The proposed final review overcomes this drawback by ensuring Ofgem have direct ability to review the whether the total volumes incurred where justified. Further by setting the final review as downside only the mechanism enables us to ensure targets are achieved, without creating an incentive for us to over-invest PCB replacement

A re-opener: this would mean that we would need to go through the full re-opener application process to secure additional allowances for PCB removal at a point in the RIIO-ED2 period. As we outline in section (b), we are reasonably certain of our unit cost estimates, and as such this would provide little benefit. It would also create significant additional drawbacks in terms of increasing the regulatory burden, making us less confident to incur the expenditure if guarantees on a known unit cost are not put in place.

No UM: this would not allow any adjustments whatsoever, and thus does not tackle the issue. Moreover, it would fail to tackle the uncertainty around the amount of replacement needed, meaning that either:

- Not all assets with PCBs would be removed or
- That we would need to significantly increase our baseline allowances to mitigate this risk, which could result in over-investment

h. Value for money for consumers

This mechanism provides value to consumers by ensuring harmful PCB material are removed from our network in a timely manner whilst preventing consumers over-paying.

This mechanism ensures that we will be able to replace PCBs to maintain the resilience, reliability, and efficiency of our network as uncertain as the total volume of these assets become clear. By preventing both under-delivery and over-investment, this mechanism will provide the maximum possible value to consumers out of all the options considered (including not applying an UM).

6.7 Ash dieback removal

a. Issues and risks that the proposed mechanism addresses

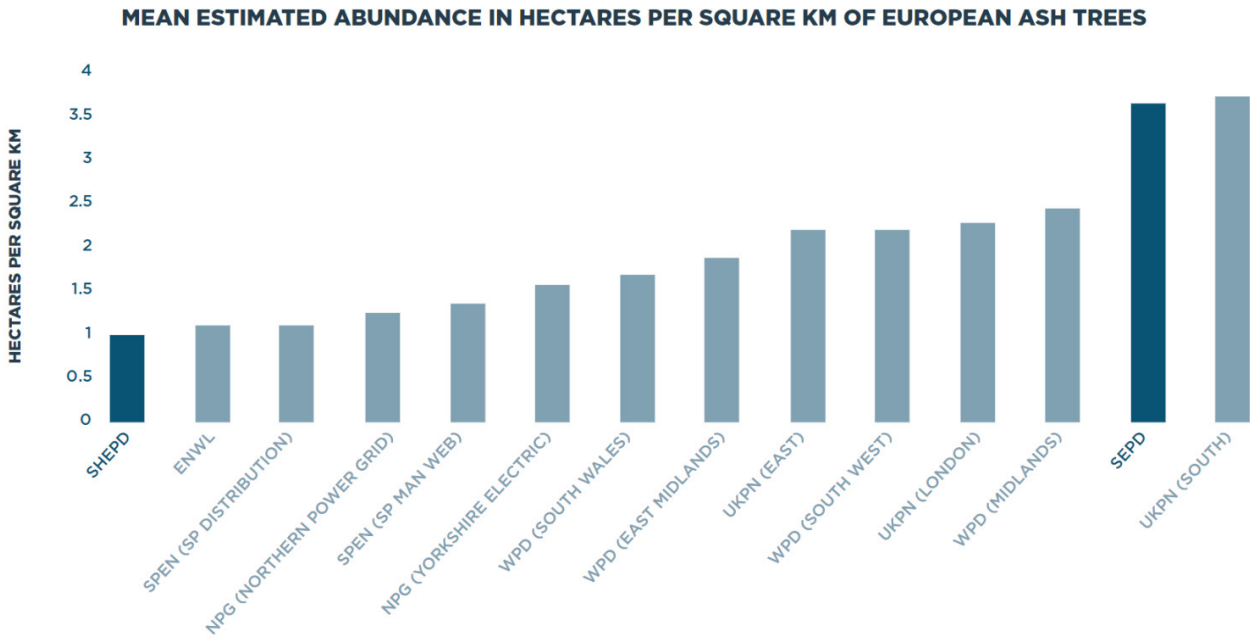
We have a legal duty to maintain overhead line networks free of interruptions, Electricity Safety, Quality and Continuity Regulations (ESQCR 43-8) and resilience standard Engineering Technical Report (ETR 132). Trees are one of the principal causes of unplanned service interruptions on lines and we are required to make networks 'resilient' to tree and vegetation damage, including during abnormal weather conditions. We undertake targeted vegetation management programmes to help achieve this, which will continue into RIIO-ED2.

Since its first identification in the UK in 2012, Ash Dieback, which is caused by a fungal pathogen – *Hymenoscyphus fraxineus*, has been detected in over 60% of 10km^2 in the UK. Research has shown that less than 20% of the UK's Ash population is tolerant to the disease.

The rate of progress of the disease within individual trees can be unpredictable and can take up to 18 months for symptoms to show after first infection as it is dependent upon environmental factors and the presence of other pathogens which may take advantage of weakness caused by the disease and hasten the trees' decline.

SEPD has the second highest abundance of Ash trees of all DNOs, see figure 6.7. Whilst SHEPD has the lowest abundance of Ash trees this does not exempt the area from the issues caused by Ash dieback. Whilst we have high level estimates of Ash abundance and a clear need to remove impacting diseased trees, we do not have complete data on proximity of diseased Ash trees to our assets. This issue is not regional specific, but rather industry wide, affecting all electricity distribution companies, as well as other utilities and infrastructure sectors with above ground assets, such as highway and rail agencies.

Figure 6.7: Mean estimated abundance of European Ash trees by DNO licence area



Many trees will ultimately die from the disease, but they will become gradually more dangerous as they decline towards death. The main risk posed by trees which are affected by Ash dieback is that weakened or damaged limbs, or the whole tree, may fall and cause injury or contact with our assets. Diseased trees create a particular challenge for us; and due to the reduced strength conventional means (manual access, climbing with chainsaws etc.) of tree removal are not always suitable and mechanical harvesting equipment with the operator in a protective cab is often required. Our experience form ED1 suggests this could be up to five times more expensive than conventional tree removal means. The cost of removal is directly linked to the state of disease within the tree. For trees at an earlier stage of decay the cost for removal can be lower as the structural integrity of the tree is better suited to conventional removal; the state of the disease can only be found following visual expert inspection. **This creates a cost uncertainty** with the exact means and effort for removal varying by site, and heavily influenced by the required safety measures.

The cost uncertainty is **compounded by volume uncertainty** with exact numbers and rates of death and decline of Ash trees in proximity to our assets difficult to predict.

Research, and the experience of those managing tree populations, demonstrates that most Ash trees in the UK which are close to property or infrastructure will need to be felled over the next few years. Additionally, Ash trees grow widely and very vigorously from seed, so, although a significant proportion of mature trees are expected to die over the next few years, the size of the overall Ash population is likely to take longer to decline.

Death rates of mature trees will also vary depending on pressures on the population from other environmental and biological factors.

We have responsibility for Ash dieback management in proximity to our assets, where a tree is considered at risk of contact. The need case to remove these trees is clear and is a requirement ESQCR. Consideration for stakeholders, and budgetary implications, mean that removing all Ash trees within the vicinity of the overhead line network as part of a mass felling exercise funded through the ex-ante baseline plan would not be feasible, and would not gain the desired permanent network resilience due to the expected regeneration of new trees. It will therefore be necessary to plan an ongoing monitoring and cutting schedule which is flexible and responsive to manage the evolving threat to the network throughout our licence areas.

In the current price control period, ED1, we have managed the prevalence of diseased trees through our ongoing tree cutting budget, although the growing rate of diseased trees, since first being detected in 2012 and their high costs for removal have created significant strain on this allowance and is one of the reasons for overspend. Given the increasing cost and volume uncertainty associated with Ash removal relative to our networks we are proposing re-opener UM in RIIO-ED2 which will allow us to trigger additional funding upon receipt of updated information from ongoing manual[16] survey work for removal during the RIIO-ED2 period. We propose the costs of manual surveying to detect Ash dieback threats in proximity to our network is covered through the baseline. We propose the total costs of diseased tree removal is only borne by consumers after a cost materiality threshold has been exceeded, consistent with the approach adopted in most other UMs.

Ash dieback will be an ongoing issue into the ED3 period and beyond. Whilst our efforts in RIIO-ED2 will remove most known diseased trees at risk of contact with our assets this will not preclude further spread into healthy trees or regeneration of new trees which subsequently become infected. It is more than likely we will require to update our tree removal strategy in preparation for ED3.

b. The design of the proposed mechanism

The proposed UM is a re-opener, with the standard materiality threshold (1% of annual allowed base revenue). We propose that we should have the flexibility to trigger this re-opener once after the standard materiality threshold has been exceeded. To trigger the re-opener, we propose we present to updated Ofgem survey data showing the extent of diseased trees in proximity to our assets and costs for removal based on disease intrusion. This data will evidence a refined cost allowances ask to cover the ongoing management of the risk to the end of the RIIO-ED2 period. We propose to complete the survey within the

[16] "Manual" survey, as we need to not only ensure we have the specific species of tree, but we must also check if an Ash tree is healthy or not. We cannot remove a healthy Ash tree 'just in case'.

first two years of RIIO-ED2 on both our networks; meaning the timing of our re-opener submission is likely to be 2025, depending on costs incurred to date relative to the materiality threshold.

The cost of the survey is included with our baseline proposal. We propose the scope of the re-opener request be narrow and focused only on the increased costs of removing diseased trees in proximity of contact with our assets. For the avoidance of doubt the re-opener would not cover costs or volumes associated with other drivers for vegetation management.

We do not consider that Ofgem should be able to trigger this mechanism, as there is no potential for downward allowance adjustment (*only upward adjustment on a zero baseline for diseased tree felling costs*) and the triggering of the ask to use the mechanisms is not conditional on Ofgem or other stakeholder decisions. We consider that it is our sole responsibility to apply for funding adjustments where required, ensuring that we provide sufficient justification for the re-opener to be used after we have exceeded the cost materiality threshold.

c. Ownership of risk under the mechanism

The cost risk is owned by our consumers. Like wider vegetation management they should bear the full cost of removing diseased trees in proximity to our assets which present a safety or security of supply issue during RIIO-ED2. It is also prudent that consumers bear the costs of surveying the tree population in proximity to our assets to determine a re-opener ask. This is consistent with costs consumers bear elsewhere to allow us to establish and refine ongoing needs cases for asset intervention.

The operational risk of managing the impacts of diseased trees in proximity to our network and ensuring compliance with the ESQCR remains with us. We have the responsibility to prevent contact with our assets and the ongoing process of identifying harmful diseased trees for removal.

d. Materiality of issue

The survey work we propose to undertake at the start of RIIO-ED2 will provide the evidence to support an accurate proposal of the costs and volumes of diseased trees for removal in proximity to our network during the RIIO-ED2 period.

To design this UM proposal, we have calculated an indicative cost estimate of an additional £48m across both licence areas (SEPD: £38.0m & SHEPD: £10.0m) to remove diseased trees, funded by the UM. This estimate is based on latest data on the abundance of Ash dieback in our licence area and current cost experience of removing these trees, which is a function of disease intrusion and can be up to five times more expensive than conventional tree removal. This cost estimate does not include the cost of surveying which is included in the baseline. Our estimated costs for Ash removal do not include the additional c.£5-£15m that will be spent in the first two years of RIIO-ED2 to remove the highest risk trees as we continue survey work, although we expect the full costs of felling to be recovered if the materiality threshold is breached. We anticipate a materiality threshold of c.£5-£15m depending on total RIIO-ED2 base revenue outturn (standard materiality threshold for UMs is 1% of annual allowed base revenue).

e. Frequency and probability of issue

We are proposing to make one submission to trigger the re-opener once the cost materiality threshold for diseased tree removal has been exceeded, as set out in section (b). Our experience in ED1 on felling costs suggests this trigger point is likely to be reached in 2025, which will coincide with completing detailed survey work in the first two years of RIIO-ED2.

Our probability of using the mechanisms relatively certain as we expect the intrusion of Ash dieback on healthy trees in proximity to our network to continue to grow aggressively for the reasons outlined in section (a). Further as also noted in section (a) the issue of Ash dieback will be ongoing issue into ED3 and beyond. We anticipate reviewing our strategy again prior to ED3.

f. Justifications for the proposed mechanism

The proposed mechanism is a re-opener, covering 100% of the felling costs post materiality threshold. We believe this to be prudent as the need case to remove these trees is clear there remains cost and volume uncertainty associated with diseased tree removal which can only be refined post detailed survey work. A re-opener is well suited to managing cost and volume uncertainty. There are other mechanisms design options we have considered although we do not regard these as appropriate in this case:

- Including a portion of the felling costs within the baseline and only including a re-opener to cover the revised costs and volumes upon receipt of updated survey data. Whilst this option is attractive to us as it gives a higher degree of relative certainty on allowances for felling removal, we do not think this would be in consumers interests. The evidence to support a baseline funding ask is not yet substantive and requires a more detailed survey to ascertain the volume of diseased trees in proximity of our assets and their costs for removal based on rates of intrusion. We believe funding should only be released once this data is available. Further, we support the application of a standard cost materiality threshold for Ash dieback. This will ensure we bear the initial cost risk for diseased tree removal and only trigger for the full costs once the ongoing costs become significant.

- A volume driver mechanism would not be in the interest of consumers since there is relative cost uncertainty on unit rates required to remove the trees. This unit rate varies by the level of intrusion of disease on the tree and the terrain being operated in. Whilst it will be impossible to develop a unit rate for each individual tree, we expect our update survey work to give us a more accurate assessment of the level of intrusion and the level of effort required to remove trees across the network. This in turn will enable us to present a more refined and up-to-date set of volumes and unit rates for removal which a re-opener mechanism is better suited to.

- A close out mechanism at the end of the RIIO-ED2 period to cover logged-up and evidenced costs of diseased tree removal was considered to be a significant cashflow risk to us given our indicative assessment of the total feeling costs expected in RIIO-ED2, as set out in section (d). This approach may be appropriate in some lower cost areas of the plan or where the need to trigger a re-opener is particularly uncertain given the ongoing evolution of a discrete topic which may reduce its probability of use. In this case however the probability is highly likely and we believe a re-opener during the RIIO-ED2 period ensure the costs of managing Ash dieback can be agreed as soon as relative information is available, which avoids cash flow risk and gives consumers certainty on bills as early as possible.

- Not having an UM would not be appropriate given the substantial volume uncertainty around the total number of trees to be removed and the cost range associated with removing individual trees. The need for consumers to fund diseased tree removal is clear and we are required to comply with ESQCR; the uncertainty hangs on when that funding should be released. The consequence of not having an UM is either a substantially higher baseline proposal for diseased tree removal which would be largely speculative in its construction; or a low ineffective baseline which would be quickly exceeded, exposing consumers to cost overruns. The re-opener UM allows us to bring forward an accurate funding request once the specific removal need is known.

g. Drawbacks of the proposed mechanism and mitigations

Through our mechanisms design we have removed the principle drawback which is the lack of evidence to support a baseline allowance proposal for diseased tree removal. Our proposed mechanism recognises the need to remove diseased trees is clear, but the total costs and volumes associated with removal are still to be determined.

By only funding after the materiality threshold has been exceeded and upon publication of detailed survey data, we are removing from consumers any risk that the materiality of this issue is not current in the RIIO-ED2 period. Consumers will only pay once the materiality is proven.
We will continue to remove diseased trees whilst the survey is undertaken and so safety and security of supply risks to consumers are not impacted.

h. Value for money for consumers

As the level of Ash dieback and the infection rates and impact are still unknown the UM is the best approach to minimise the impact to consumers. As set out in section (g) our proposed mechanism recognises the need to remove diseased trees is clear, but the total costs and volumes associated with removal are still to be determined. By only funding after the materiality threshold has been exceeded and upon publication of detailed survey data, we are removing from consumers any risk that the materiality of this issue is not current in the RIIO-ED2 period. Consumers will only pay once the materiality is proven. We will continue to remove diseased trees whilst the survey is undertaken and so operational risks to consumers are reduced.

6.8 Strategic Investment

The Strategic Investment Uncertainty Mechanism drives significant potential changes to allowances, and also has the most potential complexity in that the design of this mechanism represents a significant departure from the ED1 re-opener approach to Load Related Expenditure uncertainty. As such, a substantive appendix to this annex has been created, to explain and discuss our proposed approach to Strategic Investment specifically. A brief description of how the mechanism addresses each criteria of a UM is presented below; however further detail should be sought in the appendix.

a. Issues and risks that the proposed mechanism addresses

Whilst there is a clear need for substantial Strategic Investment, there remains significant uncertainty over the volume, timing, location, and type of investment required. The need for additional network capacity will be driven by a range of factors, including key trends outside of our control such as the development and uptake of LCTs, consumer behaviour and new government legislation.

As Ofgem rightly acknowledges in the RIIO-ED2 SSMD, DNOs must strike a careful balance between investing proactively enough to support rising demand and prevent system overload, whilst also investing efficiently and minimising the risk of stranded assets. DNOs should also minimise bill increases for consumers, ensuring that costly reinforcement of the network is only applied when alternative options, such as use of market-based flexibility services, are insufficient to meet consumers' current and future needs.

Recognising these important trade-offs and the need to provide flexibility over RIIO-ED2 investment (as the net zero transition evolves), Ofgem's RIIO-ED2 SSMD proposes an UM for Strategic Investment, as well as a separate net zero re-opener mechanism to cover impacts from new net zero targets or legislation (or other related developments). We welcome both of these proposals, and we are continuing to engage with Ofgem on their design and parameters. We consider a key difference between the Strategic Investment UM and the net zero UM to be the nature of their impacts on investment. We envisage the Strategic Investment UM to cover incremental changes (including potentially large changes) in load-related investment as needed to deliver additional network capacity, whereas the net zero re-opener will cover new net zero targets or legislative decisions (or other related developments) that necessitate a quantum change on our costs and outputs (including but not limited to load-related investment).

b. The design of the proposed mechanism

In line with Ofgem's RIIO-ED2 SSMD, we are proposing a volume driver mechanism which will adjust cost allowances based on the net capacity delivered by load-related investments in each year. We consider that the mechanism should provide for annual allowance adjustments, based on pre-agreed unit costs. The full detail of our design is outlined in ***Strategic Investment UM (Appendix 17.1.1)***

c. Ownership of risk under the mechanism

Our proposed volume driver will result in risks being shared between us and our customers. Should we deliver less capacity or circuit length than we've set out in our baseline plan, the mechanism would facilitate for the return of allowances to customers. Equally, however, there may be a need for additional investment over RIIO-ED2 to deliver the required network capacity, then customers will contribute towards the cost of this. Our baseline proposals focus on high certainty works (that is, those needed in the least aggressive scenario considered) as well as works that avoid foreclosing our most aggressive credible scenario. This approach minimises the risk that any baseline funded assets could be stranded, protecting consumers.

We will bear the risk that outturn unit costs are higher than our unit cost allowances. This risk is also two-sided, in that we will benefit should we achieve cost efficiencies relative to our unit cost allowances.

We consider that this balance of risk is appropriate and aligned to customers' interests. Given the challenges in forecasting the level of investment required, and the magnitude of this investment, it is important that we have the financial flexibility to deliver the optimal level of additional network capacity over RIIO-ED2. Any delays in delivering this investment could not only weaken customer service (increasing the risk of system overload and power outages), but impede GB's decarbonisation journey, creating substantial costs for wider society. The flexibility provided by the volume driver will enable us to invest efficiently based on customers' evolving needs.

The proposed approach to unit costs further strengthens the incentives for us to deliver additional network capacity efficiently, creating opportunities for economies of scale.

d. Materiality of issue

Our proposed volume driver for Strategic Investment will cover fluctuations in investment relative to the RIIO-ED2 baseline plan (on an annual basis). To estimate the cost uncertainty range associated with this volume driver, we have therefore calculated the maximum projected underspend and overspend relative to the baseline, based entirely on the DFES 2020 scenarios. Applying this approach, we derive an expenditure range of £268m to £538m across our two licence areas combined, relative to a baseline of £298m (equivalently, the potential variance from the baseline is -£30m to +£240m).

This breaks down as follows across our licence areas:

- For SEPD, the expenditure range is £206.0m to £408.9m relative to a baseline of £226.8m (equivalently, the potential variance from the baseline is -£20.8m to +£182.1m).
- For SHEPD, the expenditure range is £61.6m to £129.2m relative to a baseline of £71.1m (equivalently, the potential variance from the baseline is -£9.5m to +£58.2m).

e. Frequency and probability of issue

The proposed volume driver will have an annual application, fed by our stakeholder engagement and annual planning process. The probability of the mechanism being applied is high, given the highly uncertain nature of issues such as LCT uptake and consumer behaviour, and the fact that only small deviations from baseline volume forecasts could potentially necessitate application of the mechanism (although as noted above, we would be willing to discuss the use of dead bands with Ofgem and other DNOs).

In addition to the above, we recognise that there needs to be transparency over DNOs' load-related investment decisions, to provide the required assurance that any additional investment undertaken is necessary and efficient. We consider that the Strategic Investment volume driver needs to be accompanied by a clear trigger which is consistent across all DNOs and externally transparent, which is discussed in ***Strategic Investment UM (Appendix 17.1.1)***

f. Justifications for the proposed mechanism

Our justification for each aspect of our proposed UM design is detailed throughout the Strategic Investment ***Strategic Investment UM (Appendix 17.1.1).***

g. Drawbacks of the proposed mechanism and mitigations

We recognise that the combination of volume driver parameters and supporting processes which collectively make up the Strategic Investment UM creates complexity, and there is a risk that such complexity could dilute transparency and accessibility for broader stakeholders. This is an important consideration, given the consumer interest in our contribution to net zero. We intend to work closely with Ofgem and other DNOs over the coming months to ensure that our final mechanism design is sufficiently straightforward and transparent for our stakeholders, recognising that key aspects of the UM including unit cost allowances design are subject to ongoing discussion with Ofgem and other DNOs.

A more specific potential drawback of the mechanism is the challenge involved in setting accurate unit costs. There is an important balance to strike between simplicity and granularity when developing unit cost allowances, with a need to avoid allowances which are either a weak proxy for outturn costs or very complex to administer.

To ensure we get this balance right, there should be some flexibility over how granular our unit cost allowances can be, allowing for distinctions across various cost dimensions (such as asset type or voltage

level), rather than mandating a one-size-fits-all approach. Providing this flexibility will enable DNOs to employ established analytical techniques that assess the case for different unit cost designs and identify those that strike the best balance between simplicity and granularity. We consider that such techniques could include econometric and Monte-Carlo modelling of relationships between project-level delivery costs and various explanatory variables (such as new capacity delivered or asset lengths), to ascertain which relationships are the strongest and most consistent (thereby reducing the likelihood of windfall profits or losses being incurred).

Such analysis could be used to design and calibrate unit cost allowances, and it could potentially incorporate both outturn ED1 data and forward-looking RIIO-ED2 data for a rounded view.

The most critical drawback is the concern that a volume driver could be used significantly more than forecast and result in DNO's claiming excessive allowances, impacting consumer bills. This is ideally mitigated by the robust application of forecasting and decision making that means each use of the mechanism is very well justified, and Ofgem's annual right to challenge that evidence would hold DNO's to account for only delivering activities that serve the consumer's interest. However, additional measures such as an automatic 'tramline' trigger for a re-opener if allowances breach a certain rate could be combined with this proposal to provide an additional layer of protection for consumers.

h. Value for money for consumers

We consider that our proposed mechanism offers value for money in several ways. Firstly, our mechanism provides value through its flexibility. As noted above, it is challenging to forecast how much investment will be required over RIIO-ED2, with deviations from the baseline plan being very likely. In the absence of an UM, this would risk significant underspend or overspend against baseline allowances, which could negatively impact customer service (especially if it led to system overload) and/or result in customer bills being higher than required. Our mechanism addresses both of these issues, ensuring that outturn investment is sufficient to maintain high standards of customer service whilst keeping customer bills efficient (i.e. only as large as needed to support sustainably high service standards for current and future customers).

Secondly, our mechanism recognises the pivotal role DNOs must play in supporting the net zero transition. The adoption of a volume driver signals to our stakeholders that we are making a credible commitment to invest as required to support the decarbonisation of key industries. This arguably brings positive externalities for wider society (including consumers), in that it demonstrates the supporting infrastructure required for LCTs will be put in place, and this in turn will encourage consumers to play their support in decarbonising the economy. Given that the transition to net zero will be substantially driven by consumer behaviour change, it is highly important that consumers have confidence that DNOs (and other energy network companies) are playing their part and supporting this behaviour change. Achieving this will ultimately support the cost-effective delivery of net zero emissions across wider society.

6.9 Hebrides and Orkney

a. Issues and risks that the proposed mechanism addresses

Through our RIIO-ED2 business plan we are powering communities to net zero. Our investment programme for our North of Scotland Licence area includes special factor investment for the 59 inhabited Scottish islands we serve will ensure we can maintain: (1) a safe, resilient and responsive network; (2) be a valued

and trusted service for our customers and communities; and (3) accelerate progress toward a net zero world. Scottish Islands have critical path role in delivering the UK's Government's 2050, and the Scottish Government's 2045 net zero targets.

In our baseline RIIO-ED2 plan we are setting out the following special factor investment (table 6.9 (a)) proposals relevant to communities in the Scottish Islands (excluding Shetland and Worst Served Customers):

Table 6.9 (a) – Special factor investment for Hebrides and Orkney region

Investment area	Proposal summary
Subsea cables	£184.0m
Diesel embedded generation	£45.0m

In two regions of our license area: Hebrides and Orkney islands we have two vectors of uncertainty going into the RIIO-ED2 period which creates an opportunity for us to deliver more efficient outcomes for consumers:

i. **Uncertainty on the driving need to act,** *which could include reinforcing and/or incrementally expand parts of the distribution network in the region*. The condition of certainty is resolving policy, third party, and technology choices in the region. We believe this uncertainty is likely to resolve over the next 18 months into the start of the RIIO-ED2 period. Specifically:

- We know many wind farm developers (with total capacities of hundreds of MW) are awaiting the outcome of the latest UK Government Contract for Difference auctions, expected mid-2022. These developers will need routes to market which will extend beyond the current capacity of the distribution and transmission networks. In addition, ensuring increased network capacity and redundancy is a pressing issue for several local community and enterprise groups who provide crucial local fiscal benefits to the region. Until we know the outcome of these auctions the need we are catering for remains uncertain.

- The Prime Minister has pledged (October 2021) to make Britain's electricity system "net zero carbon" by 2035, an interim target in the countries drive to net zero by 2050. This will undoubtedly require an immediate step up in efforts to achieve this landmark date and will more than likely require additional renewable investment within the Scottish Islands given their potential. It is likely that connection requests will increase over the coming months as developers leverage government incentivisation to meet this target. If this happens then the needs of a network associated with the Scottish Islands will be very different to those today.

- Whilst Ofgem have published their 'minded to' decision on Access SCR it is clear from engaging with our customers that their resulting behavioural changes will not be immediate and will only become clear once additional policy reviews, such as a review of transmission charging reforms are complete and the outcomes from the Electricity

Transmission Network Planning Review and the Offshore Transmission Network Review are better understood. We expect this to resolve in the coming 18 months which will likely alter the driving need for enabling investments

- Scotia Gas Networks (SGN) are actively reviewing through innovation funded projects future energy source to provide heat and industrial loads on the islands (**H100 and the HyCORAL**). This includes a review of the long-term future of the Stornoway LPG storage site, and the LNG storage facilities at Oban and Campbelltown. We are engaging with this review because the range of available alternatives must consider a role for electrification and a combination of alternative technologies (some of which are only just coming to market) if net zero targets are to be met. The outcome of this review will significantly influence local energy network needs in the region

- Scotland has a target to reach to reach net zero emissions by 2045. Whilst this target is clear there remains uncertainty on the optimal solution for sustainable alternatives to the vital security of supply role our seven Distributed Embedded Generation sites fulfil in the Hebrides and Orkney. The need to act as a DNO to provide the security of supply changes as other third-party factors change in the region. We must factor in potential roles for greater Distribution System Operation DSO activity through active network management, alternative technologies such as batteries and hydrogen, and further subsea reinforcement

Each one of the above items is strong enough to create a need to review the whole system needs for the Hebrides and Orkney regions. If these events occur in isolation, it may be possible in some limited circumstances to manage the impact through the range of other UMs in our plan or via the totex baseline. However, when they occur simultaneously, as they likely will, they create an unprecedent need for industry to re-evaluate from a broader whole system perspective the optimal route to fulfilling consumer need. Issues that we currently experience in the Hebrides and Orkney will not abate or disappear until some form of step change is introduced. Incremental change will never be sufficient to address the barriers and investment by individual parties and in a whole system context would be sub-optimal to the needs of consumers.

ii. **Uncertainty over the optimal type of action which is interdependent on the wider stakeholders in the region**. Once further certainty on driving need is available it will be necessary to undertake a whole system review of investment solutions considering multiple energy vectors. This assessment must consider the holistic outcomes to the region and the UK (*with the benefit for a distribution solution sitting alongside the benefits of other solutions*):

- Ensuring there is sufficient capacity to give routes to market for developers
- Maintaining security of supply, including for worst served customers
- Maximising long term socio-economic welfare for consumers and producers

To do this key stakeholders including developers, local communities & government, the Electricity System Operator, and other parts of the utility sector such as transmission and gas must be involved, alongside us as DNO. The assessment must start with a clear definition of a counterfactual including the condition of existing network assets, such as Distributed Embedded Generation, and subsea cables. The assessment must consider a range of solutions and focus on finding a solution which minimises regret across scenarios and be enduring in the long run.

There is a risk of material regret if we fully commit to one solution now without a more detailed whole system thinking in the next 18 months. However, we cannot continue to wait in perpetuity without acting if we are to meet net zero targets and enable economic progress. The next 18 months are crucial to removing the uncertainty of several moving parts and finding a solution which delivers on the outcome's consumers need for the region, but we need this to come with hard deadlines and clear target outcomes.

b. The design of the proposed mechanism

This proposed UM facilitates the investment SSEN may need to take as a stakeholder post a whole system review the Hebrides and Orkney. The re-opener will allow for either upward or downward adjustment of baseline allowances, depending on required investment by SSEN.

The mechanism we propose could be triggered multiple times upon completion of whole system assessments. The frequency will depend on the structure of the assessments adopted, which may need to be done at a sub-regional level (e.g. Inner and Outer Hebrides).

We cannot control the timelines of third parties in the process, but we accept we must set milestones by which investment decisions must be made to avoid jeopardizing delivering our emission reduction and reliability commitments. We therefore propose limited annual application windows to be available for the UM, but with sufficient latitude to recognise the emergence of a proposed solution may happen at different times for the Hebrides and Orkney. We propose the UM should only be available in first two years of RIIO-ED2, unless otherwise directed by Ofgem. This will give time to complete the whole system reviews but will ensure investments are not held in perpetuity in the need case stage, which increases security of supply risk to consumers and delays the transition to net zero that can be achieved. Placing a limited window on developing a re-opener needs case creates an urgent imperative to find a solution and act across the industry.

We do not consider that Ofgem should be able to trigger this mechanism as the need for investment is not determined by Ofgem decisions. We consider that it is our sole responsibility to apply for funding adjustments when required, ensuring that we provide the required justification.

How the UM will work with the baseline allowances

Aligned with our draft plan we believe there is a need for baseline allowances as set out in section (a). We have included a focused set of baseline investments which is our ex-ante view today. Having a baseline is critical, even though we are requesting an additional UM. The baseline will allow us to progress development in the region in the event a whole system review cannot be completed in the time available. As noted, we cannot wait in perpetuity and stand-by in the constant belief that better information will be revealed which could change the investment needed. Whilst we do this, we are foregoing benefits to producers and consumers that additional capacity from our baseline will provide. The baseline therefore is our 'back-stop'. We need to commit to stakeholders that they will get genuine improvement in the event certainty cannot be found through a whole system assessment. As above, the limited time windows associated with applying to use the UM create the necessary constraints to allow this backstop to kick-in so that a solution can be delivered in the RIIO-ED2 period.

To protect consumers through this we propose the re-opener be symmetrical and that the baseline funding is subject to a Price Control Deliverable (PCD). This will ensure: (a) baseline funding can be removed and replaced with the most efficient whole system solution, if this is required; and (b) if the uncertainty persists and the baseline works are not undertaken the PCD will return unused baseline allowances, thus protecting consumers in the event of complete inaction. We propose the PCD will not be applicable in the event Ofgem do not decide post submission of a proposed re-opener adjustment by SSEN.

How the mechanism will interact with other UMs

We know this UM could have overlap potential with other UMs, so we have carefully considered the scope of the proposed re-opener to ensure it is distinct from our other proposed UMs in several ways:

- **Load Related Expenditure (Strategic Investment)** – whilst both mechanisms will deal with load related capacity considering whole system solutions, the Hebrides and Orkney Whole Systems re-opener will focus on higher quantum projects which require a re-opener rather than a volume driver and include network resilience (non-load) investment drivers. Moreover, it will consider our investments to decarbonise our network by finding alternatives to Distributed Embedded Generation on the islands as part of an integrated solution. The Strategic Investment UM would technically not have the scope to cover these investments.
- **Net zero re-opener** – whilst both mechanisms focus on the higher quantum investments to achieve net zero; the Ofgem proposed net zero re-opener does not have a network company trigger, or role for DNOs on the Net Zero Advisory Group. Having a network company trigger is essential for enabling whole system outcomes in the region and our proposal will enable this.
- **Coordinated Adjustment Mechanism (CAM)** – whilst both mechanisms related to whole systems the CAM is specifically focused on the transfer of funding between network companies, if required following a whole system assessment. The CAM cannot increment or decrement funding if the whole system assessment identifies alternative solutions are more efficient for consumers. Should it be necessary we would seek allowances through the Hebrides and Orkney Whole System re-opener to use the CAM to transfer allowances to another network company following the whole system assessment. This would be needed if another RIIO-2 regulated network company doesn't have the mechanism to deliver the funding for the whole system outcome identified.
- **Subsea cable UMs** – whilst both related to subsea cables and Distributed Embedded Generation our proposed UMs for subsea cables specifically focus on post-fault expenditure. Whilst there could be a coincidental cases a faulty cable that need to be replaced in the next 12 months forming part of the Hebrides and Orkney Whole Systems re-opener there is still a need for a separate subsea cable UM to cover faulted cables for the full duration of RIIO-ED2.

c. Ownership of risk under the mechanism

The risks associated with this mechanism are shared between consumers and SSEN. It is right consumers should fund and reap benefit from the most economical and efficient solution following a whole system assessment. Should there be a need for additional distribution investment following the whole system assessment over RIIO-ED2 to deliver the required network capacity, then customers, like other investment, should bear the cost for this if they are getting the benefits.

SSEN will continue to maintain the operational responsibility of maintaining security of supply in the region through the RIIO-ED2 period, including responding to faults on existing assets. SSEN will also be responsible of managing the efficient operation of diesel sites whilst alternative solutions are found and implemented.

There is a risk that a whole system solution cannot be found in the time available and we propose to mitigate this risk by including an efficient level of baseline spend within our ex-ante plan. This will ensure consumers have a 'back-stop' that delivers benefits within the RIIO-ED2 period. Should the unlikely event occur where the baseline plan is also undelivered due to inaction on the part of SSEN then we propose a PCD associated with the baseline to further protect consumers.

We consider that this balance of risk is appropriate and aligned to consumers' interests. As set out in section (a) there is real and significant uncertainty across two vectors which is outside our control and could result in significant deviations from the baseline. The alternative of solely funding through the baseline and not having a UM would not reduce risk to consumers and would not be appropriate given that it potentially foregoes the opportunity for consumes to find more beneficial solutions. It would also prevent us from fully fulfilling our whole system licence obligations in the interest of consumers.

d. Materiality of issue

Our estimate materiality range associated with this UM is -£151.0m to £275.6m. The lower end of this range is calculated on an assumption that a portion of our ex-ante baseline spend could be replaced by third party whole system solution. The table sets out the range and underpinning assumptions:

Table 6.9 (b) – Lower range of Hebrides and Orkney UM cost materiality range

Investment	Lower end of UM materiality range	Assumptions for ex-ante investment removed
Outer Hebrides	£51.3m	Sky-South Uist (2); Laxay-Kershader (2); Eriskay- Barra; Loch A'Choire (North & South); South Uist to Eriskay
Inner Hebrides	£20.4m	Mainland –Kerrera (1&2); Coll-Tiree; Mull – Iona
Orkney Isles	£40.1m	Hoy-Flotta; Mainland-Shapensay; Pentland Firth West; Mainland – Hoy
Remote diesel generation	£40.1m	Battery Point works; Bowmore works; O&M costs; fuel costs

The upper end of this range is based on 'do minimum' lifetime costs of a distribution solution. We don't know what types of options could be assessed through a whole system assessment, so we have based our assessment on a 'do minimum' distribution solution which would implicitly have to be signed onto in the event that no whole system solution can be found in order to maintain security of supply and to reduce emissions as far as possible. The table below sets out the range and the underpinning assumptions:

Table 6.9 (c) – Upper range of Hebrides and Orkney UM cost materiality range

Investment	Upper end of UM materiality range	Assumptions of continued investments
Outer Hebrides	£160.1m	Continued use of diesel standby + Carbon cost for Battery Point, Arnish, Loch Carnan, and Barra
Inner Hebrides	£21.2m	Assume double circuit on Jura to Mainland and Islay, rendering diesel running to extreme exceptional events
Orkney Isles	£93.3m	Third cable to Orkney and Kirkwall runs only for extreme exceptional events

e. Frequency and probability of issue

We anticipate that the re-opener will be used in the RIIO-ED2 period. We have already begun initial work on structuring a whole system assessment and will undertake the in-depth assessment through 2022.

The frequency of the UM is likely to be between one and three times during the RIIO-ED2 period. This reflects there may be a timing difference in completing the regional whole system assessments. We will look to minimise this by submitting multiple assessments, where possible to reduce regulatory assessment burden on Ofgem. As noted in section (b) we propose the mechanism should only be used in first two years of RIIO-ED2.

f. Justifications for the proposed mechanism

We believe the need for a mechanism is justified in three parts:

1. As set out in section (a) there is a clear external uncertainty which exists going into the RIIO-ED2 period. This uncertainty sits across two vectors and is a known unknown with a potential to create a large variance from what we know today (and have included in our baseline). We also believe the probability of this uncertainty resolving is within the next two years high. There are very public and distinct events which could trigger the need for different investment solutions, which will only be revealed through a whole system assessment

2. It is not appropriate to manage the risk through the ex-ante totex baseline. The scale and scope of variance is such that to manage further distribution funding through the baseline we would have to either significantly increase our ask or not undertake multiple other investments. Whilst we have signalled the baseline ask which could be impacted, we proposed safeguards to ensure consumers ultimately only pay for what is delivered

3. No other mechanism is sufficiently suitable to cover the funding and scrutiny required through the whole system process. As set out in section (b) there is a clear distinct need case for this mechanism which overcomes the limited scope of other proposals

This UM achieves two vital and material results. It will identify the efficient allowances necessary to meet customer need once third-party uncertainty has reduced and in the process, unlock the opportunity to use

those allowances to create material whole system solutions for the most remote and economically challenged areas of our network.

At this point in time, we cannot create the necessary allowances to address need because of third party uncertainty and we cannot create a whole system solution because we do not yet know the value of investment which all parties can bring to the table.

Ultimately, we require this mechanism to fulfil our role in a whole system assessment to the fullest extent and to secure funding for Diesel Embedded Generation replacement. Without a mechanism we would be limited by the ex-ante baseline in the scope, scale and level of innovation in solutions we can bring into the assessment as a distribution company because we would not have the optionality to provide the funding to unlock additional investments even if cost benefit analysis supported them for consumers.

g. Drawbacks of the proposed mechanism and mitigations

A potential drawback in UMs is that they can create too much flexibility for the DNO. If they are not clearly defined on when they can be used and the frequency of use there is a risk they incentivise companies to continue wait until better information comes around, which can results in inaction and lost benefits. In the case of whole system assessments with multiple stakeholders this 'waiting' is more likely as the DNOs cannot control the timetable of third parties. We have sought to mitigate this risk by limiting the frequency of application for the UM to the first two years of RIIO-ED2 and including the baseline spend in our plan. This creates the imperative to act now, but it also ensures consumers continue to benefit in the event of delays to the whole system assessment.

h. Value for money for consumers

We consider that our proposed re-opener offers strong value for money for consumers. It strengthens our requirement to undertake whole system assessment across multiple energy vectors thereby ensuring the most economic and efficient solution to a multitude of regional issues is developed. It also ensures as a distribution company we can bring a full scope of conventional and innovative solutions into the whole system assessment, thereby maximising the choice range to consumers and helping to discover what is really value maximising to socio-economic welfare. The re-opener recognises that the there are several ongoing requirements which are unique to the Hebrides and Orkney regions which are not mutually exclusive and cannot be resolved today. The re-opener will ensure a holistic approach is taken to addressing these issues.

Our approach additionally provides broader value to customers, from a social, economic, and environmental perspective. Our proposals will ensure the most economic enduring solution which maximises socio-economic welfare in the region is found which ensures renewable generators can stay connected to the mainland grid and reducing the need for diesel-powered island generation. Our proposals will also reduce the environmental footprint of our island communities and support the transition to net zero, ultimately benefiting consumers right across our licence areas.

6.10 OpEx adjustor

a. Issues and risks that the proposed mechanism addresses

We have set out through this annex that some of our Capital Expenditure (CapEx) investment requirements are uncertain, and as such we require additional CapEx UMs alongside those proposed by Ofgem. For the same reasons that CapEx investment requirements are uncertain there is also uncertainty in corresponding future Operating Expenditure (OpEx) associated with some of these UMs. Specifically, there is likely to be a requirement to adjust allowances for Closely Associated Indirects (CAIs) to match the new capital investment landscape CapEx UMs sets.

The uncertainty in OpEx is linked only to a sub-set of our CapEx UMs proposals in this annex. Not all CapEx increases will result in an automatic substantial rise in OpEx. Our baseline plan includes efficient ex-ante OpEx aligned with the level of ex-ante baseline CapEx we are proposing. This includes significant efficiency improvements relative to ED1. It does not include 'head room' to cover additional OpEx which would be associated with some of our UMs and would be outside our ability to manage through the ex-ante baseline. Further as Ofgem are proposing to set the allowances on an activity level, pre-capitalisation for RIIO-ED2 the ability to make OpEx adjustment is needed to recognise the additional impact of CAIs from the delivery of CapEx through UMs.

We therefore consider that an adjustor for CAIs is appropriate linked to the level of CapEx which is increasing on the trigger of specific CapEx UMs. This overall approach proposed is consistent with that used in electricity transmission for RIIO-T2.

b. The design of the proposed mechanism

Our proposed approach to manage the OpEx uncertainty linked to specific CapEx UMs is to use an automatic OpEx adjustor. This automatic adjustment would be based on the same formula used to establish the relationship between workload driver, CapEx and efficient CAIs in our baseline plan, to be administered by Ofgem at the Draft Determinations. This means there would be a percent increase of the baseline CAI allowance for each individual licensee for a 1% of increase of CapEx allowance above the baseline allowance through specified UMs. The percent increase would be set on a consistent basis to the approach used to determining efficient CAI baseline allowances (*i.e. using the coefficient for CapEx from the POLS regression analysis*). The mechanism would only be triggered in the year corresponding to the delivery of the additional CapEx and could be used at any point in the price control period. This is consistent with the approach used in transmission.

We propose the specific CapEx UMs which a CAI adjustment would be applicable to are (and for which cost materiality ranges are included in our plan):

- Load Related Expenditure (Strategic Investment)
- Wayleaves & Diversions
- Polychlorinated Biphenyls
- Environmental Legislation

We also propose the UM is also applicable to following CapEx UMs for which cost materiality ranges are currently unquantifiable, but would result in significant additional CAI if applied:

- Rail Electrification

- Net zero re-opener

c. Ownership of risk under the mechanism

The ownership of risk is consistent with the CapEx UMs which the OpEx escalator corresponds to, as set out in section (b), and described for each of the UMs we propose elsewhere in this annex.

We propose the OpEx adjustor is only triggered in either the year corresponding to the associated CapEx UM, for CAI. This ensures SSEN manages operational cost risk up until additional CapEx has been approved or delivered and additional funding cannot be provided before this. SSEN will continue to manage the operational cost risk associated with other UM not associated with the OpEx adjustor.

We believe this is a fair balance of risk between SSEN and our consumers. Our baseline CAI reflects an efficient level of spend for our baseline allowance proposals and include no 'head room' for additional large capital expenditure. If the CapEx funded through the UMs were to be more certain today, we would have included these in our baseline and re-calibrated the CAI proposed allowance. The provision of the OpEx allows for this efficient re-calibration at the appropriate time and not before.

d. Materiality of issue

As set out in section (b) we propose for CAI the percent increase would be set on a consistent basis to the approach used to determining efficient CAI baseline allowances i.e. using the coefficient for CapEx from the POLS regression analysis at Draft Determinations. However, in advance of this we have calculated using available information from all DNO draft plan submissions (excluding UK Power Network) a regression coefficient of 0.3035% for CAI. On this basis we calculate a total range for the UM as set out in table 6.10. This range is based upon applying the regression coefficient to the CapEx UMs set out in section (b).

Table 6.10 – Cost materiality range for CAI component of OpEx adjustor UM

Company	Baseline CAI	Lower range	Upper range
SHEPD	£278.8m	£275.6m	£313.4m
SEPD	£502.4m	£493.4m	£598.8m

e. Frequency and probability of issue

The frequency of use for this uncertainty mechanism will be directly linked to the corresponding CapEx UMs and will be triggered either in the corresponding year for CAI. Given the spread of spend in the corresponding CapEx UMs we have in our plan we believe it is highly likely that the OpEx adjustor will be triggered more than once and possibly in every year during the RIIO-ED2 period.

f. Justifications for the proposed mechanism

Our core justification for this uncertainty mechanism aligns with the issues this mechanism is trying to address as set out in section (a) and more generally our timely delivery of net zero requirements. It provides us with OpEx allowances when CapEx allowances are funded through the relevant UM and

ensures that overall OpEx allowances is calibrated to efficiently link to the total CapEx in an efficient manner. We have not included 'head room' within our baseline OpEx allowance to account for large capital adjustments and so this UM provides for this only when required, thus protecting consumers.

We do not believe it is credible to link all CapEx UMs to the adjustor given some will entail minimal OpEx changes which would be within the standard percent of base revenue materiality threshold for UMs. We have only linked the OpEx adjustor to those CapEx uncertainty mechanisms which have a material likelihood of OpEx increases is greater than the base revenue materiality threshold.

Whilst it would be possible to include OpEx components within each of the corresponding CapEx UMs we do not believe this approach is justified given the timing of required revenue differences between CapEx and OpEx linked to the uncertainty.

g. Drawbacks of the proposed mechanism and mitigations

A drawback potentially associated with this proposed uncertainty mechanisms is the scope of CapEx associated with the mechanisms, and whether UMs not included in the scope could result in significant changes to OpEx but are not covered by the OpEx adjustor. In this scenario the DNO could be potentially absorbing a substantive risk and may be disincentivised from pursuing the associated CapEx UM. Whilst this is a potential drawback of the mechanism for DNOs on balance we believe it would not be prudent to subject all CapEx UMs to the mechanism. It is correct the company should bear the risks of OpEx increases in some cases where these are less than the base revenue materiality threshold for instance. Through our analysis of our plan and experience we have carefully selected the CapEx UMs OpEx adjustments should be applicable to as set out in section (b).

h. Value for money for consumers

Consumers principally get value through this UM by ensuring we can efficiently deliver associated CapEx UM. The RIIO-ED2 period will be characterised by much higher use of UMs than previous periods. These cannot be delivered without efficient funding for CAI and NOCs. It would not be in the interests of consumers to include 'head room' in the ex-ante allowances to cover OpEx costs linked to uncertain CapEx. Without this proposed UM, we would have significant limitations in our ability to prepare and execute re-openers within period to the quality required to withstand the high bar of regulatory scrutiny. This could in turn limit our ability to deliver the scale and pace of change consumers require from us to reach net zero, potentially displacing critical investments into the RIIO-ED3 period or beyond.

7. OUR VIEW ON OFGEM'S CONFIRMED UNCERTAINTY MECHANISMS

In this section, we provide our view on the UMs proposed by Ofgem in the RIIO-ED2 SSMD, some of which are also applicable to the T2 and GD2 controls and some of which are specific to RIIO-ED2.

The first part of this section explains our position on the common re-opener parameter proposals set out by Ofgem in the SSMD. The second part of this section then explains our position on each of Ofgem's proposed mechanisms individually, considering:

- Our view on the scope of the UM and Ofgem's proposed parameters (where these have been defined).
- Our view of the cost uncertainty range associated with each UM, which contributes to our broader analysis on the aggregate financial impact of uncertainties at RIIO-ED2. We explore the aggregate financial impact of our UMs further in the section 8 of this document.

The second part of this section does not include coverage of the Ofgem-proposed UMs which are linked to financeability and the return on capital. For commentary on these mechanisms and their associated cost impacts, please see ***Finance and Financeability (Chapter 19)*** of our business plan:

- Inflation indexation of RAV and allowed return.
- Cost of debt indexation.
- Cost of equity indexation.
- Tax review.
- Real Price Effects.

The second part of this section also does not include coverage of the following pass-through mechanisms, which are used to automatically adjust allowances for costs which fall outside of our control:

- Ofgem licence fee.
- Business rates.
- Pensions adjustment.

7.1 Our position on Ofgem's confirmed common re-opener parameters

In this sub-section, we explain our position on the common re-opener parameter proposals set out by Ofgem in the RIIO-ED2 SSMD. It should be noted that the positions we outline below apply across the full set of additional UMs we set out earlier in this document, insofar as we propose to apply Ofgem's common re-opener parameters. For example, we are proposing to apply the standard re-opener materiality threshold across most of our additional re-openers, and this sub-section sets out our overarching position on the calibration of the materiality threshold (which applies across these re-openers).

The position we outline below should be read in conjunction with our October 2020 response[17] to Ofgem's Sector Specific Methodology Consultation (SSMC), although the below text supersedes our SSMC response in several areas (reflecting Ofgem's proposed changes at SSMD).

RE-OPENER APPLICATION WINDOWS

In the RIIO-ED2 SSMD, Ofgem proposes to maintain its SSMC position. Re-opener application windows have been brought forward from May to January, and the time period for applications has been reduced from one month to one week (the last week in January).

We continue to disagree with Ofgem's decision to shorten the application window to one week, and we consider that application windows should be at least two weeks long to allow for high-quality re-opener applications to be prepared and submitted. Moreover, our internal governance process to approve re-opener applications requires more time to be completed appropriately. Our proposal is in both DNO and Ofgem interests, as it supports an efficient decision-making process for re-opener applications.

AUTHORITY TRIGGERED RE-OPENERS

In the RIIO-ED2 SSMD, Ofgem proposes to moderate its approach towards triggering re-openers. Having previously proposed in the SSMC that Authority triggers should apply to all re-openers, Ofgem now proposes that the use of Authority triggers should be decided on a case-by-case basis. Where Authority triggers are included, these will be subject to the same scope and materiality thresholds that apply to re-openers triggered by licensees.

We support Ofgem's decision to moderate its approach at SSMD, and we agree that the use of Authority triggers should be decided on a case-by-case basis rather than being applied automatically to all re-openers. We note that Ofgem's revised RIIO-ED2 approach is aligned to the T2 and GD2 final determinations in this respect.

As noted in our SSMC response, where Authority triggers exist, the Authority should have to abide by the same re-opener application windows as DNOs, rather than being able to trigger re-openers at any time (which would create major challenges for planning our resources). Moreover, in cases where it proposes to use Authority triggers, Ofgem should consult on its proposals and provide DNOs with an opportunity to share their views.

Of the additional UMs described in section 6 of this document, we consider that an Authority trigger should not be applied to any of the following re-openers:

- Subsea Cables (reactive replacement re-opener; remote generation re-opener; cable decommissioning re-opener)
- Ash dieback removal
- Hebrides and Orkney Whole Systems

[17] **Our response to Ofgem's SSMC**

We do not consider that an Authority trigger is appropriate for these UMs, for several reasons. Firstly, the baseline cost associated with each of these re-openers is £0, and therefore there is no potential for downward adjustment of allowances (only for upward adjustment). We note that in its RIIO-ED2 SSMD, Ofgem cited the potential for reductions in DNO workload (relative to the baseline plan) as a key driver for applying Authority triggers, but this rationale does not apply to the re-openers listed above. Secondly, the triggering of these re-openers is not dependent on decisions made by Ofgem (with some of these re-openers instead being dependent on decisions made by other public bodies). Thirdly, given that these re-openers only involve upward adjustment of allowances, we consider that it is our sole responsibility to apply for funding adjustments where required, ensuring that we provide sufficient justification for the relevant re-opener(s) to be used.

RE-OPENER MATERIALITY THRESHOLDS

In the RIIO-ED2 SSMD, Ofgem proposes to apply a default materiality threshold for re-opener applications, which it has provisionally set at 1% of annual average base revenues (after application of the relevant TIM rate), subject to a full consultation at draft determination. This is a continuation of Ofgem's SSMC position. Ofgem also proposes not to allow an aggregation process for re-openers to meet the materiality threshold, which represents a change from its SSMC position. Ofgem similarly decided to remove the re-opener aggregation process in the T2 and GD2 final determinations.

We disagree with Ofgem's proposal to set the materiality threshold at 1% of annual average base revenues (after application of the TIM rate). We note that in this respect Ofgem's proposals do not align with the T2 and GD2 final determinations, where the materiality threshold was set at 0.5% of annual average base revenues. In contrast, Ofgem has followed the same approach as T2 and GD2 in disallowing re-opener aggregation. We consider that Ofgem should follow a fully consistent approach across price controls in relation to materiality thresholds, especially because some of Ofgem's proposed RIIO-ED2 re-openers are cross-sectoral (including the net zero re-opener). The use of a 1% threshold risks preventing DNOs from putting forward re-opener applications that would be accepted under the T2 and GD2 controls, and we do not consider there to be a valid justification for this.

7.2 Our position on Ofgem's proposed common uncertainty mechanisms

In this section, we explain our position on each of Ofgem's proposed common UMs individually.

SMART METER INTERVENTIONS

Sector: **ED only**

Type: **Volume Driver**

Description of Ofgem proposal: The mechanism proposed by Ofgem in this area is identical to the analogous mechanism included in ED1. It will automatically adjust DNO allowances based on the number of callouts related to smart meter installations. This mechanism will adjust our allowances if the number of callouts actually required differs from this assumption. Ofgem adjusted our allowances in accordance with license area specific unit costs in ED1. To incentivise DNOs to reduce callouts, a tapering mechanism was also applied, with the unit cost falling once the callout rate passes a certain threshold.

Our estimate of materiality over RIIO-ED2: We do not foresee a material deviation to our baseline costs for smart meter interventions in RIIO-ED2.

Our view on the mechanism: We agree with Ofgem on the need for an UM. Moreover, our ED1 experience suggests that a volume driver following Ofgem's design is appropriate.

CYBER RESILIENCE

Sector: **Cross-sector**

Type: **Re-opener**

Description of Ofgem proposal: Given the "ever-evolving landscape associated with cyber risk", there is uncertainty around the requirements DNOs will face, as these may change due to new risks or new regulation. This mechanism will enable DNOs to apply for adjustments to their allowances during a single mid-period re-opener window if they can demonstrate material changes in the amount of cyber resilience (OT and IT) spending they require. Ofgem stated it will "consult on any materiality threshold" for this re-opener.

Our estimate of materiality over RIIO-ED2: Based on our planned and potential cyber resilience projects during RIIO-ED2, our baseline costs are £[redacted]m for SEPD and £[redacted]m for SHEPD, and we anticipate a materiality range relative to these baselines of -£[redacted]m to +£[redacted]m for SEPD and -£[redacted]m to +£[redacted]m for SHEPD.

Our view on the mechanism: We agree with Ofgem on the need for flexibility in allowances related to cyber resilience during RIIO-ED2. Ofgem's SSMC Appendix 2 stated that the scope of this re-opener covered "new cyber resilience activities, new risks or threats, as well as new statutory or regulatory requirements that are not subject to baseline allowances". Our view is that the scope of this re-opener needs to be broad, with DNOs able to make re-opener applications based on any rationale, rather than being limited to a clear external trigger. This will ensure that DNOs are funded for this critical and ever-evolving aspect of their business plans, given the extensive uncertainty on the future nature of cyber resilience requirements. In response to Ofgem's decision to consult on any materiality threshold, our view is that Ofgem should follow the precedent it sent at T2 and GD2 in setting no threshold for this mechanism.

ELECTRICITY SYSTEM RESTORATION (BLACK START)

Sector: **ED Only**

Type: **Re-opener**

Description of Ofgem proposal: This mechanism has been introduced to deal with possible changes to regulations as a result of the Black Start guidance due to be published by the Secretary of State. There is potential for additional costs as a result of changes to the guidance, particularly with respect to the mandatory resilience period, which is currently set to three days, but is being reviewed with the potential for an extension of the resilience period to seven days. This would increase the level of fuel required for generators and the volumes of batteries required at substations that need to be made resilient.

Ofgem have stated that this mechanism could be removed if black start guidance is confirmed in time. The standard materiality threshold will apply.

Our estimate of materiality over RIIO-ED2: We have not included baseline costs in this area. Based on historical (ED1) costs related to changes in the mandatory resilience period, we anticipate that the materiality range relative to this zero baseline is £0 to +£14.0m for SEPD and £0 to +£7.0m for SHEPD.

Our view on the mechanism: We agree with the need for a mechanism in this area. However, we consider that no materiality threshold should apply to this mechanism. Similar to our Access SCR mechanism, our costs in this area are dependent on an imminent decision outside our control, which if made sooner would have enabled us to included costs in our baseline, without a materiality threshold needing to be passed.

Even if Black Start guidance was published before the start of RIIO-ED2, we would not have time to plan and accurately assess the efficient costs we require to action any changes to our business plan we require as a result. As such, we consider that Ofgem should not leave the option open to remove this mechanism.

ENVIRONMENTAL LEGISLATION

Sector: **ED Only**

Type: **Re-opener**

Description of Ofgem proposal: This mechanism has been designed by Ofgem to deal with potential changes in legislation and/or regulations that will affect the plan of work described in DNOs' Environmental Action Plans (EAPs). Under the proposal, both Ofgem and DNOs will be able to trigger the re-opener, with the standard materiality threshold and annual application windows being applied.

Our estimate of materiality over RIIO-ED2: We consider the most material area of uncertainty under Environmental Legislation to be SF_6 legislative requirements, with the potential for new legislation at RIIO-ED2 which requires us to replace network assets containing SF_6. Our baseline spend incorporates the investment needed to reduce SF_6 leakage in line with our science-based emissions reduction targets, with an associated cost of £5.4m for SEPD and £0.2m for SHEPD. Since we are committed to achieving this reduction, the low end of our cost uncertainty range is identical to our baseline.

However, there is a material chance of new legislation which will require additional cost. The high end of our cost uncertainty range assumes that we have to network assets containing SF_6, and we estimate that this will cost £89.3m for SEPD and £34.1m for SHEPD. This creates cost uncertainty ranges of £0 to +£89.3m relative to the baseline for SEPD, and £0 to +£34.1m relative to the baseline for SHEPD.

Our view on the mechanism: We support the inclusion and design of this re-opener. We note that whilst SF_6 reduction is the most material area of uncertainty, there is a possibility of new legislative requirements in other areas within the scope of the EAP, and it is right that the re-opener covers this.

STREET WORKS

Sector: **ED Only**

Type: **Re-opener**

Description of Ofgem proposal: This mechanism has been carried over from ED1, and Ofgem is not currently proposing to make changes for RIIO-ED2. The existing mechanism covers additional costs associated with permitting schemes and other street works legislation not included as part of the ex-ante

allowance. The existing mechanism also covers the volumes of activity associated specifically with load-related expenditure and new connections expenditure.

Our proposed amendment: This re-opener should be amended to allow us to recover additional costs if we are mandated to handle hazardous types of spoil differently, as guided by the Environment Agency.[18] We propose the re-opener should be triggered twice:

1. After a protocol comes into force (this could be as early as 2023) – provision of the amendment to the re-opener will allow us to apply for allowances to cover one-off costs of delivering the protocol (e.g. staff up-skilling to identify waste, laboratory and establishing quarantine storage sites)

2. At the end of ED2 – this will allow us to apply for allowances to cover spend we've incurred associated with disposing of the waste aligned with the protocol

Our estimate of materiality over RIIO-ED2: We cannot calculate the materiality of spend associated with amending the re-opener today. The volume of waste classified as hazardous remains unknown and is dependent on mandates from the Environment Agency; and the cost of disposing the waste is dependent on the mandate as well. Therefore, we will only apply at the end of the period if costs are greater than the standard UM materiality threshold and Ofgem would have the right to review costs and volumes associated with our application at the end of ED2.

RAIL ELECTRIFICATION

Sector: **ED Only**

Type: **Re-opener**

Description of Ofgem proposal: This mechanism has been carried over from ED1 to deal with uncertainty around the detailed implementation of rail electrification projects. Moreover, at ED1 Ofgem stated "there are questions about who will bear the costs to the networks of these projects", with Ofgem considering that they should be recovered from rail customers. The mechanism has been expanded for RIIO-ED2 to include costs in rail electrification projects from companies that may not have a connection with Network Rail. The standard materiality threshold applies.

Our estimate of materiality over RIIO-ED2: We are currently engaging with Network Rail and other parties regarding plans for a rail electrification programme in the North of Scotland. Whilst we have an indication of the routes being considered for electrification, we have not yet received the detailed information required to define the extent of diversion works required. We are also yet to receive detailed information on either the proposed phasing of the works, or on the distribution of funding across customer bases (with a potential for financial contribution from rail customers). As a result, we cannot currently forecast the potential costs associated with this programme. In relation to the SEPD licence area, we are not aware of any planned rail electrification programmes over RIIO-ED2, but we consider that the re-opener should be made available in case a need for diversion works emerges in the future.

[18] Environment Agency Guidance RPS 211 - Excavated waste form utilities installation and repair

Our view on the mechanism: We support the inclusion and design of this re-opener, including the expansion of its scope to include companies that may not have a connection with Network Rail. We note that there are plans under development for a rail electrification programme in the North of Scotland, which includes the SHEPD licence area. If approved, this will create a need for diversion of some distribution network assets, which SHEPD may be required to fund.

NET ZERO

Sector: **Cross-sector**

Type: **Re-opener**

Description of Ofgem proposal: This mechanism is designed to supplement the strategic investment volume driver should there be wholescale changes to the profile of energy demand, due to factors that may as yet be unknown, but could include major policy or legislative changes set out by government which impact multiple sectors. Ofgem have proposed that only themselves can trigger this mechanism, and it can do so at any time during the price control, with adjustments made unilaterally if they clear the standard materiality threshold.

Our estimate of materiality over RIIO-ED2: Given the breadth of this re-opener and the types of issues it is designed for; it is not possible to judge the materiality of any adjustments to our allowances it could enable.

Our view on the mechanism: We agree with the need for an additional re-opener to deal with potential net zero related changes that are not covered by the strategic investment volume driver. However, we consider that this re-opener should be able to be company as well as Ofgem triggered, given that DNOs may have greater visibility of net zero related challenges affecting their networks. We also consider that large changes in our allowances as a result of this re-opener would need sufficient consultation with our business and other relevant stakeholders.

COORDINATED ADJUSTMENT MECHANISM

Sector: **Cross-sector**

Type: **Re-opener**

Description of Ofgem proposal: This re-opener is part of the broader whole systems approach and aims to enable outputs and associated revenues to be reallocated from one network company's price control to another network company's price control. The mechanism will also be included for the end of ED1 to coincide with the start of the T2/GD2 price controls. The annual application window for this re-opener is set in May, allowing networks to reassess options after deciding whether to submit re-opener bids in other areas in January. There is no materiality threshold for this re-opener.

Our estimate of materiality over RIIO-ED2: Given the types of issues this re-opener is designed for will only materialise in the RIIO-ED2 period after further analysis, it is not possible to judge the materiality of any adjustments to our allowances it could enable.

Our view on the mechanism: We consider this mechanism to be an important component in our industry's strive towards better whole systems solutions, and support its inclusion, and proposed design.

ENHANCED PHYSICAL SITE SECURITY

Sector: **Cross-sector**

Type: **Re-opener**

Description of Ofgem proposal: This re-opener is designed to deal with uncertainty around the possibility of changes in the scope of work related to physical site security mandated by the government.

Working with BEIS, DNOs agree and implement the Physical Security Upgrade programme (PSUP). There could be changes to the list of sites requiring security upgrades and/or the scope of changes at each site. DNOs may apply for additional funding in mid-period and end-of-period application windows. This mechanism is carried over from ED1, during which the standard materiality threshold applied.

Our estimate of materiality over RIIO-ED2:
[redacted].

Our view on the mechanism: We agree with Ofgem's proposed mechanism design in this area.

8. DELIVERABILITY AND DEPENDENCIES

In this section, we explore how our UM proposals relate to our broader RIIO-ED2 business plan, from a variety of perspectives.

Sub-section 8.1 assesses the cumulative financial impact of our UMs relative to baseline RIIO-ED2 Totex, capturing the potential upward or downward adjustments to cost allowances which our UMs could necessitate. We compare this against benchmark companies from the T2 and GD2 sectors.

Sub-section 8.2 articulates the linkages between our development of UMs and the broader RIIO-ED2 business plan. And explains how we have aligned our work closely with business plan development (recognising the need to strike an appropriate balance between baseline funding and UMs).

Lastly, sub-section 8.3 considers deliverability challenges associated with our UM proposals, both in terms of general considerations and UM-specific considerations. A major theme of these deliverability challenges is the extent to which works associated with additional UM funding can be feasibly delivered over RIIO-ED2. We describe how deliverability risks are being identified and mitigated as part of the RIIO-ED2 business plan.

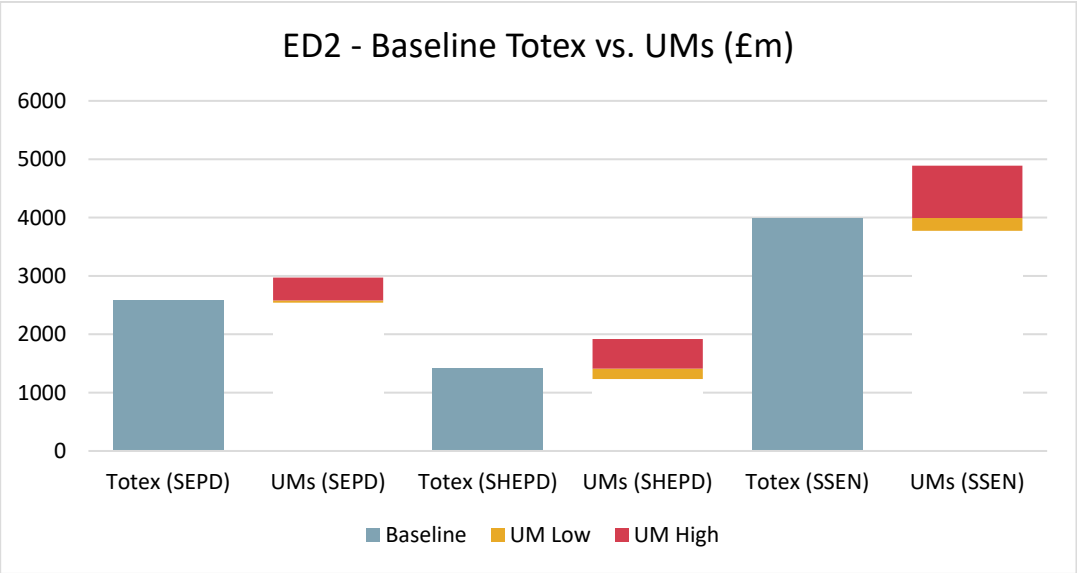
8.1 Uncertainty in the round

In our commentary on Ofgem's proposed RIIO-ED2 UMs and our additional UM proposals, we provide estimates of the overall materiality associated with each individual UM. We have formed these materiality estimates by developing cost uncertainty ranges for each UM, which aim to capture the full range of potential cost impacts associated with each UM (from low to high). In each case, we present the baseline funding allowance associated with the UM (where applicable), and we capture the potential for positive or negative cost variance relative to the baseline arising from the UM. We refer the reader to sections 6 and 7 for these cost uncertainty ranges.

In this sub-section, we assess the cumulative financial impact of our UMs relative to baseline RIIO-ED2 totex. We have calculated this by combining the lower and higher ends of our UM-specific cost uncertainty ranges, to create an aggregate cost uncertainty range which accounts for the full set of potential outcomes across our suite of UMs.

Figure 8.1 captures our aggregate cost uncertainty range relative to baseline RIIO-ED2 Totex, for SEPD, SHEPD and SSEN (Distribution) respectively. Our 'UM Low' estimates (in green) show the potential for downward allowance adjustments, whilst our 'UM High' estimates (in red) show the potential for upward allowance adjustments. This analysis incorporates both Ofgem-proposed and our-proposed UMs, although we do not include pass-through UMs, indexation UMs, RPEs or Ofgem's proposed Tax review re-opener (in line with our approach in section 7).

Figure 8.1: Aggregate cost uncertainty ranges for SEPD, SHEPD and SSEN (£m)



The above figure shows that whilst there is potential for both downward and upward cost impacts from UMs, our aggregate cost uncertainty ranges are asymmetrically tilted towards upward cost impacts (relative to baseline totex). Our two licence areas have a different exposure to downward cost impacts (around -1.5% and -12.8% of totex for SEPD and SHEPD respectively), and their exposure to upward cost impacts is slightly wider (15.2% to 35.8%). The SHEPD faces slightly greater upward relative exposure due Subsea Cables and Hebrides and Orkney UMs.

8.2 Linkages with our broader RIIO-ED2 plan

It is important that our proposed UMs are well-aligned to our broader RIIO-ED2 plan, as this will be crucial to Ofgem accepting them as suitable mechanisms which build flexibility into the price control.

This section outlines the key areas of intersection we have identified with our broader plan, discussing key considerations for each and the actions we have taken to incorporate the relevant issues into the development process for our mechanisms.

ALIGNING OUR UM APPROACH WITH THE BROADER RIIO-ED2 INVESTMENT STRATEGY

Whilst some of our UM proposals relate entirely to external developments, many others are closely linked to our broader RIIO-ED2 investment plans. There is a clear need to ensure our proposals are well-aligned to these plans. For example, our proposed mechanism designs for Strategic Investment should closely align to our broader load-related investment plans, considering a range of future energy scenarios

How we have incorporated this in our work

- We have worked closely as an integrated RIIO-ED2 team internally to develop our volume driver designs for Strategic investment, and Subsea cables.
- We have also engaged with our wider business to assess deliverability challenges linked to UMs, as elaborated on later in this section.

ENSURING BUSINESS PLAN FINANCEABILITY

UMs are a key channel through which financeability risks can be mitigated. For instance, indexation of the cost of capital protects from external market fluctuations. Moreover, the use of re-openers and volume drivers helps link allowed costs to outturn delivery, ensuring we are adequately financed under a variety of future scenarios.

However, UMs can also increase financeability risk. For example, allocating funding to UMs instead of our baseline totex increases cashflow risk, and can lead to unrecovered sunk costs if our mechanism proposals are not allowed during RIIO-ED2 (without an associated increase in baseline funding). Similarly, there is a risk that our re-opener applications may be rejected by Ofgem during RIIO-ED2, after associated costs have already been incurred.

How we have incorporated this in our work

- Working closely with experts from around our business, we have estimated the financial materiality of Ofgem's proposed and our additional proposed UMs. We have updated and refined our UM-specific cost uncertainty ranges to account for the latest baseline investment plans, and our cost uncertainty sensitivities have also been closely informed by RIIO-ED2 plan costings. This has collectively enabled us to evaluate the aggregate materiality of our UMs relative to forecast baseline Totex, as set out in section 8.1 above.
- Additionally, our regulation and regulatory finance teams have worked together to ensure that this aggregate UM impact analysis is included in broader financial risk cost modelling to assess financeability throughout RIIO-ED2.
- In designing our UMs, we have tried to restrict the potential for cashflow risk by advocating frequent re-opener windows, using volume drivers rather than re-openers where this is feasible. This improves the likelihood that necessary funding will be allocated in a timely manner once a need has been established.

BALANCING FUNDING CHANNELS (BASELINE FUNDING VS. UNCERTAINTY MECHANISMS)

UMs provide for flexible in-period adjustment of cost allowances, which is particularly valuable for RIIO-ED2 costs that are hard to predict and unforeseen. This means that DNOs are incentivised to avoid over-estimating baseline funding needs (as uncertain costs can be allocated to the relevant mechanism), which reduces the likelihood of unnecessary costs on consumer bills.

However, we recognised that UMs should not be over-used. Customers prefer reasonable certainty and stability over future bills, and dislike excess bill volatility, creating a need to target mechanisms effectively.

Restricting the number of UMs also helps DNOs and Ofgem to manage the regulatory burden over the course of RIIO-ED2. To ensure that UMs are only used when necessary, network companies also need to consider the relative merits of UMs against alternative funding mechanisms, such as Price Control Deliverables (PCDs), Consumer Value Propositions (CVPs) and Output Delivery Incentives (ODIs).

How we have incorporated this in our work

- We have engaged experts across our business to identify which cost items are hardest to reliably predict and challenging for our business to control, making a baseline-only approach unsuitable.
- We have liaised with colleagues that are developing regulatory outputs and incentives (including PCDs, CVPs, and ODIs) to consider specific cost items and evaluate the relative merits of different funding mechanisms.
- For our proposed UMs, we have carefully considered the balance between baseline funding and costs which are allocated to the UM. The baseline plan reflects reasonably certain costs with a clear ex-ante needs case, with our proposed UMs enabling appropriate adjustments around this when a needs case arises.

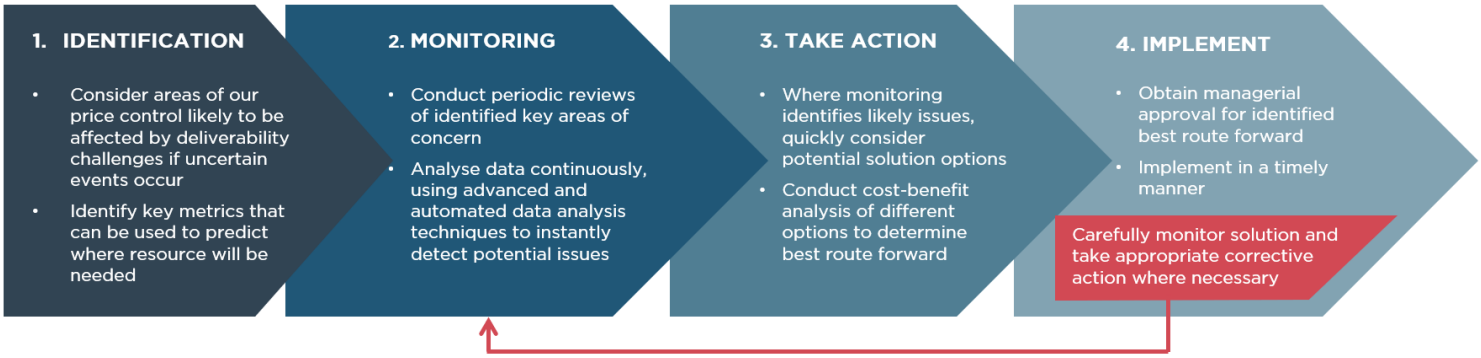
8.3 Deliverability

This section considers our UM deliverability strategy for RIIO-ED2, in addition to key deliverability challenges that are generated by the specific suite of UMs we are proposing. We consider those challenges that are likely to be relevant across our UM package, before discussing the specific challenges associated with particular mechanisms.

OUR STRATEGY FOR ENSURING DELIVERABILITY IN THE CONTEXT OF UNCERTAINTY

Given the extensive range of uncertainty we and Ofgem have identified for RIIO-ED2, we need to be proactive in ensuring that we are able to meet the needs of stakeholders in all potential scenarios. Figure 8.7 outlines how we plan to ensure our business can continue to deliver high-quality outputs for consumers in all circumstances during the price control.

Figure 8.7: Ensuring deliverability throughout RIIO-ED2



DELIVERABILITY CHALLENGES RELEVANT ACROSS OUR UNCERTAINTY MECHANISM PROPOSALS

We have identified three broad deliverability challenges relevant across our UM proposals, and to those mechanisms proposed by Ofgem.

1. A high volume of simultaneous re-opener submissions may be required to secure additional funding

The large number of re-openers likely to be included in the RIIO-ED2 price control creates a significant regulatory burden should many need to be simultaneously triggered. As such, our business may not have the capacity to build sufficient evidence to ensure that our submission meets the requirements needed to secure additional funding in each area.

How this challenge can be mitigated

As noted in section 3.1, we advocate that the streamlining of the re-opener application process undertaken by Ofgem in its T2 and GD2 final determination is also applied for the RIIO-ED2 price control. This includes the development of a re-opener application pipeline log to ensure common visibility of anticipated re-opener applications, and a tiered assessment system for applications (informed by the materiality and complexity of the application) to ensure proportionality.

2. Cash-flow timing implications of multi-stage re-opener application, approval and funding release process

As described in section 8.2, there may be adverse cash-flow implications resulting from the time lag between identifying need for additional funding that is applicable to a particular re-opener, and that funding subsequently being delivered. This could prevent the full scope of work that would be optimal for consumers being delivered in a timely manner.

How this challenge can be mitigated

We note that in the T2 and GD2 final determination, Ofgem has committed to forecasting revenues from re-openers as part of the AIP. Where re-openers are approved in time for the AIP, this will reduce the time lag between approval of funding to companies receiving revenue from the current 2 years to less than a year. We welcome this change, and we advocate that the same approach is adopted for the RIIO-ED2 price control. This will reduce the cash-flow delays we face at RIIO-ED2, especially if we need to undertake significant additional investments to support the net zero transition.

3. We are required to undertake work-at-risk prior to confirmed internal approval of re-opener application and/or Ofgem approval of re-opener funding

It may be difficult for our business to deliver certain investments that would create material benefits for consumers if the risk of starting work on these before re-opener funding is secured is deemed too high.

How this challenge can be mitigated

We are planning to review our internal re-opener application decision-making process to ensure that we can quickly make decisions on whether to apply for re-opener funding, enabling us to start projects with a higher degree of confidence that funding will be secured.

DELIVERABILITY CHALLENGES FOR SPECIFIC UNCERTAINTY MECHANISMS

Strategic Investment

As evidenced by the large materiality range we've identified for this mechanism, there is considerable uncertainty around the level of investment required to meet the challenge of delivering net zero. It is likely that labour resource constraints will be a serious challenge if more ambitious scenarios for issues such as LCT uptake materialise. There is also potential for broader supply challenges, in that it may be costly or impossible to source required equipment from suppliers.

Moreover, if there are major changes in net zero commitments or legislation that precipitate a rapid and unanticipated scale-up, this could be highly challenging. As such, the aforementioned delivery challenges are also applicable in scenarios in which use of Ofgem's proposed net zero re-opener is required.

These challenges could be present throughout RIIO-ED2, but we consider them to be of higher likelihood towards the mid-end of the price control period.

How this challenge can be mitigated

We are actively considering additional options for ensuring delivery under all feasible scenarios. For instance, transparently engaging with our supply chain to help mitigate the delivery risk associated with higher LCT uptake scenarios and defining our insourcing/outsourcing strategy and contracts to take this risk into account.

We are also considering how to reduce the likelihood of facing constraints. One aspect of this is understanding the lead times associated with delivery so that we can appropriately scale our workforce and outsourcing partners in time to deliver the required volumes in our baseline plan. Another aspect is seeking ways to use data analytics to expedite investment decisions to reduce the probability of resource constraints binding. This is heavily linked to our plan to expand LV network monitoring, which will increase the data we have access to during RIIO-ED2.

As part of our scenario-based analysis, we are considering how further changes in net zero legislation could impact our load-related investment plans to aid contingency planning.

Wayleaves and Diversions

There may be constraints on the amount of personnel available to divert assets should a considerably higher than expected wayleave terminations take place during RIIO-ED2, especially if there are clustered together. These constraints are most likely to affect our capital delivery and networks management teams, and thus could affect the other activities these teams carry out.

We consider that the challenges in this area would be most likely towards the end of the RIIO-ED2 period.

How this challenge can be mitigated

In the long-term, we are aiming to alleviate this issue by pursuing a broader strategy of converting wayleaves into easement or servitude agreements.

To tackle the immediate possibility of many diversions being required, we are developing adaptable workforce plans, taking account of required lead times for scaling up diversions activity.

Subsea Cables

As in other areas, deliverability constraints will be dependent on the outturn number of subsea cable faults during RIIO-ED2. There is a significant possibility of equipment constraints should there be a significant number of faults in a short space of time, especially since the availability and cost of vessel hire is unpredictable.

These constraints are likely to affect our capital delivery team should they occur; challenges of this nature could occur throughout the RIIO-ED2 period.

How this challenge can be mitigated

We are reviewing our overall procurement strategy for subsea cables, with a particular focus on vessel hire given this is the constraint most likely to bind. We are exploring a range of options for vessel hire, as well as seeking to maximise the range of suppliers we can draw from.

APPENDIX A – ANALYTICAL TECHNIQUES USED TO DEVELOP OUR SUBSEA CABLES REACTIVE REPLACEMENT VOLUME DRIVER

In this appendix, we provide greater detail on analytical techniques used to develop our proposed Subsea Cables volume driver, which covers reactive cable replacement works required over RIIO-ED2. We explain how we have used analytical techniques to estimate efficient UCAs which strike the right balance between granularity (cost reflexivity) and simplicity.

Alongside the reactive replacement volume driver, we are also proposing re-openers linked to Subsea Cable activities as part of our RIIO-ED2 business plan. This appendix focuses specifically on our proposed volume driver, and we refer the reader to section 6 of this Annex for explanation of our proposed re-openers.

Introduction

For uncertainties where the unit costs of delivering additional volumes of investment are relatively certain, but the volumes themselves are less certain, a volume driver UM may be appropriate. UCAs are a key component of volume drivers, and they are used to adjust allowances upwards or downwards depending on volumes (i.e. units) delivered. Examples of UCA designs include £/MW and £/km.

The first step in developing a UCA for a given volume driver is identifying the key explanatory variable(s) that can be used to create a UCA estimation model. For subsea cable reactive replacement works the length of the cable replacement and the cable rating were identified as the key cost drivers, and therefore these were the explanatory variables we selected. The 3 key UCA designs that were tested were £/km, £/MW and £/MWkm (the latter design multiplying MW by km to form a hybrid measure).

Three analysis techniques were used to identify the appropriate UCA for reactive replacement works: graphical analysis, econometric regression analysis and Monte Carlo analysis.

Figure A1.1: Scatter plots with trendlines for: left) £m/km, centre) £m/MW and right) £m/MWkm

The graphical analysis was a quick method to identify where key relationships lay and which explanatory variables had the greatest impact on delivery cost. We have carried out 23 replacement projects since 2002 with Figure A1.1 showing each of these projects plotted against their specific model variable; km, MW and MWkm.

The graphs show us that there are tangible statistical relationships present within the 3 models, which require further analysis to test how well they work when compared to the actual (outturn) costs of the projects. Although 23 replacement projects have been conducted since 2002 many of these cannot be included in our dataset for econometric and Monte Carlo analysis due to legislative changes in replacement procedures and mitigating circumstances on the project that make the reported project costs unreflective of expected project costs at RIIO-ED2. This will be further explored in the data selection section.

Data selection

Historic cable fault data was used to develop our reactive replacement unit rate. Reactive replacement data from 2002-2021 was collated, comprised of 23 projects with the reported costs all adjusted to 2020-21 prices to ensure consistency. Legislative and strategic changes in 2012 made all projects prior to 2012 redundant as replacement costs increased due to these changes. Data from 2012-2021 was therefore used, comprised of 14 projects. Of these 14 projects 5 required disqualification due to:

- datasets discrepancies in cost breakdown (2 projects).
- bundled cable works campaigns which made it difficult to find specific project costs (2 projects).
- cable installed with no protection drastically lowering project cost (1 project).

The datasets were originally split into a short cable only dataset comprised of only cables under 15km and another dataset which includes project data for all cable lengths. This split is due to the cost efficiencies that often occur at higher lengths. The projects of Skye-Harris and Pentland Firth East (32km and 36km respectively) are far longer than the average subsea cable within our portfolio (~4km), this therefore skews the data and produces a UCA that only performs well at greater lengths. This is potentially counterproductive as only 6 out of our 110 cables in operation are over 15km with 4 of these have either been replaced in the last 3 years or are planning to be replacing in RIIO-ED2.

We believe the proactive work we are conducting on some of our longer cables negates the need to include these long cables within the UM for reactive replacement. For comparison both datasets were used during analysis, however our chosen unit rate will utilise shorter cable (cables <15km) dataset.

Defining our explanatory variable

As previously discussed, identifying the key variable for use in the unit rate model is a critical part of the volume driver creation process. Regression analysis finds the line of best fit between datasets and analyses how well the explanatory data match. This analysis is used to identify the key explanatory variable; km, MW or MWkm that will be used in further analysis.

Table A1.2: Regression Analysis comparison table

Model	All Cable Data R^2 Value	Short Cable Data R^2 Value	Average R^2 Value
£/km	[redacted]	[redacted]	[redacted]
£/MW	[redacted]	[redacted]	[redacted]
£/MWkm	[redacted]	[redacted]	[redacted]

As can be seen in table A1.2 £/km performs best across all categories, with a high R^2 value across both of our datasets. This UCA design was therefore selected as the key variable for further analysis and UCA development.

UCA model

Trendline method

After deciding on a £/km model the unit rate value was calculated. The two methods that we used to do this were the trendline method and the summing method. The trendline method plots all the project costs against their associated lengths and draws a line of best fit. The gradient of this line is the unit rate and would help us predict any project cost based upon the associated cable length. The trendlines for both data sets can be seen below in figure A1.3; £[redacted]/km for the short cable only dataset and £[redacted]/km for the all cable dataset.

Figure A1.3: Trendline plots for: left) short cable only data set and right) all cable data set

[redacted]

The trendline method is useful as regression analysis can be conducted to show how well the two datasets interact. This can be seen with the inclusion of the R^2 value. The R^2 value represents how well the trendline fits the data set, a value closer to 1 defines a more accurate data set. As can be seen the "All Cable" trendline is extremely accurate with an R^2 value of [redacted] and the "Short Cable Only" method less so with a value of [redacted]. These values are useful for defining the historical accuracy of the model; however they do not show how well the model performs over a larger sample. This can be achieved using Monte Carlo analysis, which we describe further below.

Summing method

This alternative method sums the projects costs and cable lengths and then divides the two to get a unit rate as shown in table A1.4.

Table A1.4: Summing method data breakdown

UCA Model Summing Method			
Project Type	Length (km)	Cost (£)	Unit Rate (£/km)
Short Projects (<10km)	42.157	£[redacted]	£[redacted]
All Projects	110.548	£[redacted]	£[redacted]

The summing method is the conventional approach taken to finding unit rates as it accounts for cable length as opposed to an average project unit rate where small projects have as much weight as larger projects. This method helps us to account for outliers that could potentially skew the data where mitigating circumstances such as poor weather, poor mobilisation or high compensation costs were experienced on a project which are not average expenses.

Monte Carlo analysis

Monte Carlo analysis repeatedly simulates different real-life scenarios to test how well a model works. In the case of subsea cables, our Monte Carlo analysis was set up to select a specified number of the 23 historic replacement projects in each run with the aim being to get a different mix of projects each run. By conducting this type of analysis, we were testing how our volume driver would react compared to the real-life project costs.

In each run a random selection of projects were selected with their costs and key variable values (km, MW and MWkm) summed. The different models were then run in tandem to see how the prices the UCAs produce compared to the actual prices we experienced on these projects. Multiple projects were selected in each run to simulate the costs we could potentially expect each year. The Monte Carlo was simulated at 3 projects per run and then 5 projects per run. These numbers were picked as around 3 faults are expected per year and the most faults experienced in a year is 5.

An example of a 3-project run in the Monte Carlo is shown below in Table A1.5 with green highlighting where a hypothetical profit would be made for us (should our estimated £/km UCA have been applied) and red highlighting where a hypothetical loss would be made. The darker the colour, the greater the profit or loss made.

Table A1.5: Example Monte Carlo 3 project per run simulation

Project	Real Cost	£/km Sum Method UCA	£/km Trendline UCA
Project 1	[redacted]	[redacted]	[redacted]
Project 2	[redacted]	[redacted]	[redacted]
Project 3	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

We ran 10,000 simulations of the Monte Carlo model, which effectively chose 10,000 different combinations of 3 projects (or 5 projects in the 5-project run model) and calculated the difference between the £/km UCA-implied cost and actual cost for each one.

When analysing the results of the Monte Carlo estimation three key parameters were identified, which allow us to assess the reasonableness of our UCA estimates. We list and define each of these parameters below.

- **Performance:** the costs incurred when adopting the UCA model on the projects minus the real-life costs of the projects, averaged over the 10,000 model runs.
    - The difference in price between UCA and real-life costs shows how reliable the model is.

- A value close to £0 reveals a model with high performance as the UCA closely matches the real-life costs.
- Negative values represent a hypothetical loss to us i.e. we would get back less than we would spend on the projects and a positive value represents a hypothetical profit for us where we would receive more money from the UCA than we would pay for the projects. The overall objective is to get a value close to £0 as this represents a UCA with limited bias in its underlying design and is likely to be reflective of the average cost of replacing any subsea cable

- **Resilience: the standard deviation of the Performance results.**

  - The standard deviation shows the stability of the model and how much the Performance results fluctuate throughout the 10,000 model runs.
  - Standard deviation calculates the spread in results with lower values representing a more consistent dataset.
  - As the resilience is the standard deviation of the difference between UCA and real-life costs a value close to £0 shows low fluctuation in the data and that most data points lie around the mean, with the ideal mean being £0 as previously discussed.

- **Allocation of Risk: is the risk more on us or the consumer.**

  - A percentage based upon how often the projects would cost us more than the UCA would provide, relative to the 10,000 model runs.
  - A good allocation of risk would be slightly greater than 50%, in the 50-55% range.
  - This range would ensure that the risk is more on us as most of the time the UCA would pay less than the projects' cost to complete. This increases fairness for consumers as well as promoting proactive work to reduce the number of faults that occur in the first place and increasing the efficiency of the reactive replacement work that is ultimately required.

The Monte Carlo analysis was carried out for both UCA models and datasets as shown below in Table A1.6.

Table A1.6: Monte Carlo analysis results

	Set-up		Performance	Resilience	Risk
	Data Set	UCA Model	Average (UCA - Actual)	STNDEV (UCA - Actual)	Allocation of Risk
3 Projects per Run	(**Short Cables**) Sum Method	[redacted]	[redacted]	[redacted]	[redacted]
	(**Short Cables**) Trendline	[redacted]	[redacted]	[redacted]	[redacted]
	(**All Cables**) Sum Method	[redacted]	[redacted]	[redacted]	[redacted]
	(**All Cables**) Trendline	[redacted]	[redacted]	[redacted]	[redacted]
5 Projects per Run	(**Short Cables**) Sum Method	[redacted]	[redacted]	[redacted]	[redacted]
	(**Short Cables**) Trendline	[redacted]	[redacted]	[redacted]	[redacted]
	(**All Cables**) Sum Method	[redacted]	[redacted]	[redacted]	[redacted]
	(**All Cables**) Trendline	[redacted]	[redacted]	[redacted]	[redacted]

Average	(**Short Cables**) Sum Method	[redacted]	[redacted]	[redacted]	[redacted]
	(**Short Cables**) Trendline	[redacted]	[redacted]	[redacted]	[redacted]
	(**All Cables**) Sum Method	[redacted]	[redacted]	[redacted]	[redacted]
	(**All Cables**) Trendline	[redacted]	[redacted]	[redacted]	[redacted]

As previously discussed, the "Short Cable" dataset was chosen for finalising the unit rate and the "All Cable" data was included to allow comparison. The main reason for using Monte Carlo analysis was to determine which method was superior; the trendline method or the sum method. As can be seen from Table A1.6, the sum method performs better than the trendline method in almost every criterion. The extremely small average difference between UCA and actual costs highlights the strong Performance of the model. This, together with the small standard deviation in comparison to total project cost (~12% in 3 project per run and 14% in the 5 project per run simulations), results in a high degree of confidence in the model.

Figure A1.7: £/km Monte Carlo histogram showing volume driver calculated price minus actual project prices for 5 projects per run simulations: left) trendline method model and right) sum method model (both using the "Short Cables" dataset)

[redacted]

Before finalising the model, we wanted to visualise the spread of the Performance results to identify where the majority of the risk would lie should the model be adopted.

The histograms above in Figure A1.7 show the distribution of cost differences throughout the Monte Carlo simulation. The black zones represent hypothetical profit for us, where the UCA would provide us with more money than was required to fund the project and the red zones conversely represent times when we would have hypothetically lost money using the mechanism.

Conclusion

Using the results of our Monte Carlo, regression and histogram analysis a £[redacted]/km volume driver was selected as the best UCA model. This is the UCA value calculated by applying the summing method to the "All Cable" dataset, as shown in Table A1.6.

The costs covered in the volume driver will be all costs associated with the cable replacement except the costs from additional backup generation and fuel which are covered in our separate re-opener for remote backup generation costs. The £[redacted]/km volume driver for reactive replacement will ensure that efficient costs are recouped by us while minimising the risk placed on consumers. This mechanism performs well when used with historical outturn data.

APPENDIX B – DATA AND ASSUMPTIONS

In this appendix, we provide greater detail on the data and assumptions we have used to inform our estimation of cost uncertainty ranges, as presented earlier in this document. Tables A2.1 and A2.2 below provides a summary of the data and assumptions applied for each of the Ofgem-proposed and additional UMs where we have estimated a cost uncertainty range.

Table A2.1: Data and assumptions used for cost uncertainty range estimation across Ofgem-proposed UMs

UM name	Supporting data and assumptions
Cyber Resilience	• Uncertainty ranges for cyber resilience are based on the costings of a list of projects included either as part of our RIIO-ED2 baseline or as "uncertain". • We have also included an additional £[redacted]m for projects as of yet unforeseen in the upper end of our range. • It is assumed there is little scope for lower costs in this area than the baseline. • We have assumed a [redacted] SEPD: SHEPD split based on the relative size of the license areas.
Electricity System Restoration (ESR)	• Uncertainty ranges for Black Start are based on historical data. • This gave us a view of the costs of a previous 1.5-day increase in the mandatory resilience period; we then proportionately scaled this up for the 4-day increase that forms our upper end scenario.
Environmental Legislation	• Our experts in this area have identified SF_6 leakage reduction as the most material area of cost uncertainty, and this is the focus of our cost uncertainty range. • The baseline RIIO-ED2 plan includes allowance to reduce SF_6 leakage from to meet its science-based emissions reduction targets, as part of the broader Environmental Action Plan. This allowance is split across the SEPD and SHEPD licence areas. • Our UM is targeted towards potential removal of assets containing SF_6, which may be required under future environmental legislation, as opposed to reducing SF_6 leakage. There is uncertainty over the percentage of assets requiring removal, and a major removal programme (e.g. 100%) is currently infeasible due to a lack of replacement technology for some parts of our network, such as the 132kV network. • The low end of our uncertainty range involves no new SF6 legislation over RIIO-ED2, meaning that we must comply with its existing science-based emissions reduction targets. The low end of our uncertainty range is therefore identical to the baseline.

Table A2.2: Data and assumptions used for cost uncertainty range estimation across our proposed additional UMs

UM name	Supporting data and assumptions

Wayleaves and Diversions	• Our cost uncertainty ranges for Wayleaves and Diversions are informed by RIIO-ED2 spend projections under several different scenarios.
	• The baseline spend is taken from our CV5 Business Plan Data Tables for SEPD and SHEPD. This includes the CV5 sub-components 'Diversions due to wayleave terminations' and 'Diversions for highways', but not the sub-component 'Conversion of wayleaves to easements, easements, injurious affection'.
	• The upper and lower end of our cost uncertainty ranges are informed by CV5 modelling, supported by expert input, which projects RIIO-ED2 spend under a range of scenarios. This has included detailed consideration of ED1 run rates.
	• For SEPD, our cost estimates for 'Diversions due to wayleave terminations' include both (i) costs of addressing the ED1 outstanding claims of wayleave terminations (which will necessitate some diversions works), and (ii) costs of addressing future wayleave terminations which arise over RIIO-ED2. We describe how the upper and lower ends of our cost uncertainty range are constructed below. We add these estimates to our cost estimates for 'Diversions for highways' to derive our overall cost uncertainty range for SEPD.
	  ○ Our baseline includes the outstanding claims budgeted for the baseline RIIO-ED2 plan.
	  ○ The upper end of our range includes upward cost impacts from a larger ED1 outstanding claims than in the baseline, and a higher volume/cost of future wayleave terminations than in the baseline.
	  ○ The lower end of our range includes downward cost impacts from a lower volume/cost of future wayleave terminations than in the baseline.
	• For SHEPD (unlike SEPD), there are no ED1 outstanding claims for Diversions due to wayleave terminations. Our cost uncertainty ranges for Diversions due to wayleave terminations therefore solely capture costs of addressing future wayleave terminations which arise over RIIO-ED2. We add these estimates to our cost estimates for 'Diversions for highways' to derive our overall cost uncertainty range for SHEPD.

Shetland	• To derive an uncertainty range for current supply solution costs, we have analysed ED1 data which captures outturn and projected ED1 Shetland costs relative to baseline Shetland cost allowances. We have extrapolated a plausible cost uncertainty range based on this data. The lower cost scenario involves lower costs than in the baseline, whilst the upper cost scenario involves higher costs than in the baseline.

	• To derive an uncertainty range for future standby solution costs, we have assumed that Lerwick Power Station is used as the long-term standby solution (Ofgem appears minded to approve this). In our lower cost scenario, expenditure is required for blackout avoidance equipment at LPS (anticipated to be provided by the market in the form of battery plus synchronous condenser), but there is no need for expenditure on an AC chopper (as a potential means of delivering 'ride through' capability for faults linked to transmission-connected wind). In the baseline and upper cost scenarios, expenditure is required for both blackout avoidance equipment and an AC chopper, to meet higher levels of demand, and / or the costs of integrating with the transmission ANM scheme. • To derive an uncertainty range for the new transmission link, we have modelled the impact of a +/-10% variance in the outturn cost of the link, capturing the impact on the SHEPD contribution using the official contribution formula.
Subsea Cables	• Our cost uncertainty ranges have been closely informed by historic data on subsea cable faults. • Although our RIIO-ED2 plan includes baseline funding for some subsea cables activity, including proactive replacement, inspection and cable repair costs, we have captured the baseline as £0 here because there is no baseline provision for the specific cost items included in our UMs (i.e. reactive replacement, responsive replacement, remote backup generation tied specifically to subsea cable fault response and cable decommissioning). • To derive an uncertainty range for reactive replacement, we have studied historic SHEPD data on cable faults. This shows an average of 3.2 faults per year, with 1.4 leading to repair and 1.8 leading to replacement. The upper end of our range assumes a run rate of 1.8 faults requiring reactive replacement per year at the average historic cost of replacement. Given the emphasis placed on proactive (and responsive) replacement at RIIO-ED2, it is unlikely that the need for reactive replacement will remain as high as the historic average. • Our uncertainty range for remote backup generation uses historic SHEPD data on the estimated costs of mobile and embedded generation tied to subsea cable fault response over 2020-21. The upper end of our range assumes that the costs incurred in 2020-21 will be repeated across all five years of RIIO-ED2. • We have not estimated a cost uncertainty range for cable decommissioning, as there is considerable uncertainty over the nature and scope of future requirements imposed by Marine Scotland (and the equivalent public authorities in England), and there is limited precedent for decommissioning activities. This creates significant challenges for cost estimation.

Hebrides and Orkney Whole Systems	To calculate the cost materiality range, we have used the following data and assumptions
	
	Lower end cost materiality range
	
	• Range set on assumption the UM would remove **£151m** of baseline spend from our plan because third party whole system solution is more economic
	• For the Outer Hebrides this is **£51.3m** and equates to removing the following investments from our baseline plan:
	  ○ Skye-Uist (2): £[redacted]
	  ○ Laxay- Kershader (2): £[redacted]
	  ○ Eriskay- Barra: £[redacted]
	  ○ Loch A'Choire North: £[redacted]
	  ○ Loch A'Choire South: £[redacted]
	  ○ South Uist to Eriskay: £[redacted]
	• For the Inner Hebrides this is **£19.7m** and equates to removing the following investments from our baseline plan:
	  ○ Mainland –Kerrera: £[redacted]
	  ○ Mainland –Kerrera (2): £[redacted]
	  ○ Coll-Tiree: £[redacted]
	  ○ Mull – Iona: £[redacted]
	• For the Orkney Isles this is **£40.1m** and equates to removing the following investments from our baseline plan:
	  ○ Hoy-Flotta: £[redacted]
	  ○ Mainland Orkney -Shapensay: £[redacted]
	  ○ Pentland Firth West (2): £[redacted]
	  ○ Mainland Orkney – Hoy: £[redacted]
	• For the remote island generation (diesel) this is **£40.1m** and equates to removing the following investments from our baseline plan:
	  ○ Battery Point works: £[redacted]
	  ○ Bowmore works: £[redacted]
	  ○ Other works: £[redacted]
	  ○ Operations and Maintenance (excl. Mechanicals and Civils): £[redacted]
	  ○ Diesel fuel costs (excluding mobile generation): £[redacted]
	
	Upper end cost materiality range
	
	• We don't know what whole system solutions could outturn, so to set a range we have calculated the 'do minimum lifetime costs' for distribution
	• Continuation of the existing security of supply solutions (diesel) or further subsea cable investment is the do minimum cost for distribution
	• For the Outer Hebrides this is **£161.0m** and equates to continued use of diesel as a standby on the Outer Hebrides (over a 45-year period) for Battery Point, Arnish, Loch Carnan and Barra accounting to the table below:

	Volume (ml/ CO2e)	Toal cost (£m)	PV Cost (£m)	Notes
Diesel costs	[redacted]	[redacted]	[redacted]	Diesels burn at average ED2 levels Excluding fault conditions; Diesel £[redacted]/ltr + 1% pa inflation
Fuel premium	[redacted]	[redacted]	[redacted]	
O&M costs	[redacted]	[redacted]	[redacted]	
Capital replacement	[redacted]	[redacted]	[redacted]	
Carbon value	[redacted]	[redacted]	[redacted]	Costing carbon intensity of sites using Ofgem carbon values from CBA model
Total			**161.0**	

- For the Inner Hebrides this is **£21.2m** and equates to reducing the diesel stations at Tiree and Islay to extreme event running only and inserting a double circuits on all subsea cables, above that set out in the baseline plan. This ensures security of supply whilst minimising carbon emissions. The table below outlines the supporting assumptions:

		Length (km)	£m/km	Fixed costs (£m)	Total costs (£m)
Tiree	Mull- Coll	10	[redacted]	[redacted]	[redacted]
	Coll-Tiree	8.2	[redacted]	[redacted]	[redacted]
Islay	Mainland – Jura (2)	9.0	[redacted]	[redacted]	[redacted]
	Jura – Islay (2)	2.0	[redacted]	[redacted]	[redacted]
	Reduced running costs of diesel plant				[redacted]
	Total				**21.2**

	• For the Orkney Isles this is £93.3m and equates to reducing the running time of Kirkwall power station to extreme event only running and providing security of supply through a third cable from the mainland to Orkney at 66kV and complete

Distributed Generation Monitoring	• We first produced an estimated number of sites potentially affected by increased DG monitoring requirements under four categories: EHV, HV, LV half hourly metered, and LV non-half hourly metered.
	• As EHV sites already have good visibility, costs will likely be close to 0 for these, so we have not included any costs for them.
	• We estimated unit costs for HV and LV half hourly metered under the following assumptions:
	  ○ HV connections assumed to be 1MW and above and hence require a permanent connection at an average cost of £[redacted]k.
	  ○ LV connections are assumed to be less than 1MW and hence require a dial-up connection which we will provide via a cellular network at an average cost of £[redacted]k.
	  ○ A permanent connection presently costs £**xxx** in annual support costs. Cellular tariffs are highly dependent on data use, but we assumed £96 per annum.
	  ○ We assume data is entered into existing systems.
	  ○ We assumed that the majority of LV sites have reliable cellular coverage (as satellite data tariffs are c. [redacted]x higher than cellular)
	  ○ We assumed that the majority of HV sites are in close proximity to telecoms networks, or satellite solutions with a latency of c.4 seconds are acceptable.
	  ○ We assumed that we would accept limited redundancy in communications circuits.
	• We then assumed that LV non-half hourly metered unit costs would equal LV half hourly metered unit costs. This is an upper bound, as it is likely costs would be lower in the category. This is balanced by the fact that many of the above assumptions reduce the upper bound of cost.
	• We multiply assumed unit costs and volumes and sum across Capex and Opex for each area to generate total costs across RIIO-ED2 for each of our license areas.

OpEx adjustor	• Determine using the draft BPDT to find industry regression on CapEx costs against CAI. For each £1 uplift in CapEx costs what is the subsequent uplift in CAI costs – this being the variable costs, and what is residual being the assumed fixed costs for running a DNO. • Coefficient for CAI then applied to the following CapEx UMs:

	○ Load Related Expenditure (Strategic Investment) ○ Wayleaves and Diversions ○ Environmental Legislation ○ Polychlorinated Biphenyls
Strategic Investment	• Our cost uncertainty ranges for Strategic Investment have been built using forecast load-related expenditure under the 4 DFES 2020 scenarios (Steady Progression; System Transformation; Consumer Transformation; Leading The Way). • Our experts in this area have identified load-related investment projects for RIIO-ED2, and they have mapped these against the 4 DFES scenarios to give total forecast expenditure under each scenario. • The baseline expenditure used in our calculations aligns with our broader RIIO-ED2 plan, and this assumes that the Consumer Transformation scenario materialises over 2023-2025, and the System Transformation scenario materialises thereafter. • For SEPD, the upper end of our range is driven by the difference between the baseline and the full Consumer Transformation scenario (which alongside Leading The Way drives the most requirements). The lower end of our range is driven by the difference between the baseline and the Steady Progression scenario (which is the least ambitious). • For SHEPD, the upper end of our range is driven by the difference between the baseline and the Consumer Transformation scenario (which is the most ambitious). The lower end of our range is driven by the difference between the baseline and the Steady Progression scenario (which is the least ambitious).

APPENDIX C – DE-PRIORITISED UNCERTAINTY AREAS

In this appendix, we provide greater detail on our de-prioritised uncertainty areas, explaining why we have chosen to de-prioritise them rather than including them within our additional UM proposals. For each uncertainty area, we briefly outline the uncertainty considered, and we then provide a primary reason together with supporting justification for its de-prioritisation. Should further evidence come to light between the draft and final business plan submissions we are not foregoing the right to re-consider the need for any of these are areas as potentially requiring an UMs.

Economic Climate Uncertainty

Summary of uncertainty: As the UK begins its recovery from the COVID-19 pandemic, there is uncertainty over how the economy will evolve during the RIIO-ED2 period. UK economic performance in the years ahead will be shaped partly by the speed and strength of the post-COVID-19 recovery (domestically and internationally), as well as new trading partnerships signed following the UK's departure from the EU.

Primary reason for de-prioritisation: This is a systematic risk which is managed through setting of the asset beta in the cost of capital

Justification for de-prioritisation decision: There is always a degree of economic uncertainty and following recent developments relating to Brexit and COVID-19 vaccination. As is consistent with established regulatory precedent for RIIO-2 systematic risks impact affect the cost of capital because they are non-diversifiable. Additionally, there are already multiple Ofgem-proposed indices which control for economic change, including indexation of the cost of capital and Real Price Effects (RPEs).

Political Uncertainty

Summary of uncertainty: Whilst political uncertainty regarding the UK's future EU trading relationship has now largely dissipated, there remains some political uncertainty about the constitutional future of the UK, with the possibility of a Scottish independence referendum during the RIIO-ED2 period.

Primary reason for de-prioritisation: UMs are not our preferred approach for managing uncertainty in this area

Justification for de-prioritisation decision: Whilst a Scottish independence vote could have far-reaching implications, it is highly challenging and inappropriate to forecast the overall cost impacts for the purpose of an UM at this stage, which would depend on multiple factors. We do not consider that a UM should be used to solely manage uncertainty in this area, as a Scottish independence vote may require broader review of institutional arrangements.

Visual Amenity

Summary of uncertainty: There is uncertainty over the volume (and cost) of undergrounding works required to reduce visual amenity impacts of existing network apparatus in Areas of Outstanding Natural Beauty and National Parks. We note that Ofgem awarded a re-opener for visual amenity improvement

works in the ET2 final determination, but for RIIO-ED2 it proposes to retain the existing funding approach based on a use-it-or-lose-it (UIOLI) allowance.

Primary reason for de-prioritisation: Lack of sufficient materiality (low impact of variance from baseline)

Justification for de-prioritisation decision: After considering the relative merits of different funding approaches, we consider that the UIOLI approach Ofgem proposes in its RIIO-ED2 SSMD is most suitable for DNOs. Whilst the RIIO-ET2 final determination includes a related re-opener, we recognise that the potential for visual amenity damage is greater for transmission network infrastructure than distribution network infrastructure (especially in the SHEPD licence area, where our infrastructure does not include a 132kV network). We estimate that the cost uncertainty impacts of future undergrounding works are relatively limited, and the existing UIOLI mechanism provides some flexibility over funding. We therefore propose to adopt Ofgem's suggested UIOLI mechanism.

Health Pandemic Costs

Summary of uncertainty: The global Covid-19 pandemic experienced over 2020-21 arguably creates an elevated risk of health pandemic costs for RIIO-ED2, with the potential for new virus variants which could trigger additional lockdowns (especially if they prove resistant to existing vaccines). This could lead to a recurrence of the business impacts we and other DNOs have experienced over the last year, creating additional costs.

Primary reason for de-prioritisation: Lack of sufficient materiality (low impact of variance from baseline)

Justification for de-prioritisation decision: Although the Covid-19 pandemic has disrupted some of our usual business operations, its financial impact has been manageable, thanks in part to existing regulatory mechanisms which have provided protection. Recent developments in Covid-19 vaccination suggest that the risk associated with Covid-19 is likely to diminish before the start of RIIO-ED2. Moreover, the risk of additional pandemics (unrelated to Covid-19) remains relatively low. Taking all of this into account, we do not consider there to be a sufficient materiality case for a UM linked to health pandemic costs.

Flooding Resilience

Summary of uncertainty: There is uncertainty over the extent of flooding resilience expenditure we will be required to undertake at its 132kV and EHV sites over RIIO-ED2, to ensure compliance with the latest ETR 138 regulations (published in 2018). At ET2 final determination, Ofgem allowed a re-opener for Medium Sized Investment Projects (MSIP), which includes a specific trigger linked to updated ETR 138 guidance on flooding and/or a direction from BEIS to protect sites from flooding.

Primary reason for de-prioritisation: Lack of sufficient uncertainty (low probability of variance from baseline)

Justification for de-prioritisation decision: Overall, we do not consider there is a sufficiently strong case to propose a UM related to flooding resilience. Given that the latest changes to ETR 138 regulations occurred in 2018, we do not envisage a high probability of further updates to the regulations over the RIIO-ED2 period.

Non-NARM Asset Expenditure

Summary of uncertainty: In the RIIO-ED2 SSMD, Ofgem explains that it is considering the use of an UM for asset replacement expenditure which is not covered by the Network Asset Risk Metric (NARM) mechanism. At ED1, this expenditure has been funded through baseline allowances which are subject to the TIM, but without the use of associated outputs or delivery targets to monitor delivery. Ofgem's suggestion for a potential UM follows its decision not to adopt any of the three possible funding approaches identified in its RIIO-ED2 SSMC (Multi-asset Volume Driver; Notional Risk Weighting; Fault Rate Measure). Ofgem suggested that an UM will be a more appropriate way to adjust DNOs' cost allowances based on output delivery.

Primary reason for de-prioritisation: UMs are not our preferred approach for managing uncertainty in this area

Justification for de-prioritisation decision: We have carefully considered Ofgem's suggestion to apply an UM for non-NARM asset expenditure. We note that Ofgem has not yet specified its preferred mechanism design, and we have therefore evaluated the potential for several different UM types. We support Ofgem's objective of ensuring greater accountability over non-NARM expenditure at RIIO-ED2, with there being a need for either outputs or an UM to adjust allowances based on delivery. We considered the use of regulatory outputs if appropriate in combination with the baseline allowance as an alternative to an UM approach.

We set out in below our evaluation of various funding strategies for non-NARM asset expenditure, highlighting key challenges associated with each of these.

UM approaches

Re-opener design

- A re-opener design could allow for some transfer/trading of asset repair and refurbishment activities across asset classes, maximising flexibility (in keeping with the principles of the NARM mechanism) and potentially allowing for additional costs to be awarded where there is a strong needs case.
- However, a re-opener would require in-period applications by either Ofgem or DNOs to adjust allowances, increasing regulatory burden. This could prove challenging, given the limited availability of data relating to non-NARM assets.

Volume driver design

- A volume driver would provide for flexible allowance adjustments, with less regulatory burden placed on Ofgem and DNOs compared to a re-opener.
- However, there are challenges associated with designing a volume driver, and Ofgem has already stated its intention not to pursue the Multi-Asset Volume Driver option.

- Firstly, an automatic volume driver mechanism arguably isn't suitable for non-NARM expenditure, as it implies that volume over-delivery automatically leads to improved outcomes for customers. This is arguably not the case for asset repair and replacement activities, where the risk reduction benefits of intervention must be carefully weighed against the costs.

- Secondly, a volume driver could restrict DNOs' ability to transfer/trade investment across asset categories as network insights improve over RIIO-ED2 (or otherwise disincentivise this).

Use-it-or-lose-it allowance design

- In practical terms, the use of a UIOLI allowance would be similar to the combination of a baseline allowance and PCD. This option could have the advantage of incentivising DNOs to put forward ambitious non-NARM approaches as part of their baseline plans, in the knowledge that customers would be fully re-compensated for under-delivery (noting the absence of cost sharing for UIOLI allowances).

- However, a key disadvantage of UIOLI allowances is that they provide very limited flexibility for over-delivery. As mentioned above, there is no cost sharing associated with these allowances, meaning that DNOs must bear the full cost of any overspend without contributions from customers. This would arguably disincentivise DNOs from delivering higher volumes of asset repair or replacement works than under the baseline plan, even if a clear needs case for additional works emerged during RIIO-ED2.

Baseline funding approaches

Baseline allowance plus regulatory output

- The baseline funding approach for non-NARM assets is well-established, having been used at ED1. The use of a baseline-led approach would avoid the aforementioned complexities associated with either a re-opener or volume driver mechanism, and the addition of regulatory output would provide upfront transparency over required volumes at RIIO-ED2.

- A baseline plus regulatory output approach would be quite similar to a UIOLI allowance approach, but with the notable advantage of cost sharing. This means that customers would contribute towards overspend on non-NARM assets, thereby providing greater incentives for DNOs to exceed the volume targets set through the output should this be in customers' interests. This ultimately provides greater flexibility over DNO funding than a UIOLI approach.

Having carefully considered all of the above options, we believe that a baseline allowance plus regulatory output is the best way to fund non-NARM asset expenditure at RIIO-ED2, as opposed to an UM. This approach provides continuity from ED1, whilst ensuring greater DNO accountability over the delivery of asset repair and replacement works. Our position is also informed by key disadvantages we have identified with the various potential UM designs. We have significant concerns about the practicality of either a re-opener or volume driver mechanism, and we consider that a UIOLI allowance is broadly similar to a baseline plus regulatory output but with the notable disadvantage of reduced flexibility.

We believe that a baseline allowance plus regulatory output is the best way for Ofgem and DNOs to collectively build towards more comprehensive NARM coverage in the longer-term, supporting an expanded NARM mechanism in ED3 as the long-run solution for asset management incentivisation.

LV Monitoring

Summary of uncertainty: In our draft RIIO-ED2 business plan we set out a proposal for a UM linked to the role out of LV monitoring on our network. We said the total volume of LV monitors required on the network is uncertain with a clear link to the growth in network constraints driven by rising demand. Whilst we set out a baseline deployment plan for monitors, we felt it necessary to include a UM which gives flexibility to install additional monitors as dictated by growing constraints.

Primary reason for de-prioritisation: A need to focus on network visibility rather than LV monitoring as the primary outcome for the network

Justification for de-prioritisation decision: We pressure tested the needs case for all our UMs following submission of our draft RIIO-ED2 plan; and reflected on stakeholder feedback. For LV monitoring we decided to withdraw our proposal as we believe the UM would create the wrong incentives for network companies, in the context of needing to focus on visibility, by not encouraging us to:

- Use the full spectrum of data and analytics, such as smart meters and advanced analytics to get the best picture of our network
- Find efficiencies in our baseline deployment programme which can lead to more monitors being installed using our ex-ante allowance

Access SCR

Summary of uncertainty: In our draft RIIO-ED2 plan we set out a proposal for a UM linked to the Access Significant Code Review. We noted that submission of our final RIIO-ED2 business plan is timed for release between Ofgem's 'minded to' and their final decision on Access SCR, and consequently there is a possibility of further cost adjustments after our final business plan is submitted.

Primary reason for de-prioritisation: There are other UMs, namely load related expenditure, which we feel would serve this purpose better.

Justification for de-prioritisation decision: Whilst there is a likelihood of further change required to our plan because of an alteration between the 'minded to' and final Ofgem decisions we believe the load related expenditure UM will have sufficient latitude to resolve these. Our final RIIO-ED2 baseline plan includes some adjustments, such as the impacts of a shallower connection boundary on C2 connection costs, but the wider impact of customer behavioural changes, impacting table CV1-CV4 remains unknown. We believe the load UM can address this and any changes between the minded to and the final Access SCR decision by Ofgem.

Radio Spectrum Allocation

Summary of uncertainty: In our draft RIIO-ED2 plan we set out that we, and other DNOs, are considering ways to move toward a private radio communications network for the control of our assets. A prerequisite

to this is a sufficient portion of the UHF radio spectrum being allocated to the use of a private utilities radio communications network by the UK government. Whenever spectrum is allocated, we will be able to begin the design and construction of relevant equipment to make use of the newly formed private communications solution. We noted in our draft plan that government are likely to take a decision on spectrum allocation in the RIIO-ED2 period triggering a review and changing of radio network design.

Primary reason for de-prioritisation: We believe the decision is unlikely to be made before 2028 (last year of RIIO-ED2) and as such cost for any implementation are better assessed through the RIIO-ED3 business plan.

Justification for de-prioritisation: We do not believe the uncertainty is material in the RIIO-ED2 period following a pressure test of our proposals and even if triggered earlier than 2028 it would still require a decision by SSEN to switch to a private radio network. We believe justification of costs therefore are better handled in RIIO-ED3.

APPENDIX D – ENHANCED ENGAGEMENT

- **Overview**: Uncertainty mechanisms (UMs) allow Ofgem to make adjustments to DNOs' allowances in response to changing developments during ED2. Depending on the specific UM, they can be triggered by the DNO and/or Ofgem.
- **Total cost**: +22.5% /-5.5% relative to baseline
- **Contribution to customer bills**: For SEPD £2.80 added to the average annual RIIO-ED2 Domestic Bill. For SHEPD the equivalent figure is £16.10.
- **Value to customers**: The use of UMs provides us with flexibility to adjust allowances during ED2, which reduces the need for contingencies in the baseline funding settlement (thereby resulting in greater totex efficiency and lower bills for customers). UMs also provide customers with protection should there be a need to adjust allowances downwards.

RIIO-1 context

UMs formed part of the regulatory framework at RIIO-ED1; we have a number of UMs, most of which also apply to other DNOs. For ED2, Ofgem proposes to continue many of these ED1 UMs and discontinue others. The focus of our RIIO-1 UMs was largely on re-openers, which had a limited number of application windows with only one volume driver (for smart meter rollout). At ED2, Ofgem is placing increased financial emphasis on UMs, especially in terms of supporting the journey to net zero

Engagement synthesis

Stakeholder engagement	
Engagement details	**Insights derived**
Academics We engaged with experts from academic institutions about our proposed Uncertainty Mechanisms via a round table	• When asking academic Institution's stakeholders about the principles we could use to understand stranded assets and the uncertainty mechanisms design one stakeholder encouraged us to engage with groups and find out their future plans; citing the Response Project in Dundee they felt the more information we have about what's occurring at ground level, the better our network investment and management plan will be, rather than forecasting from a desk-based approach. more information from what is developing will better inform our network investment and management plan [E152] • When asking Academic Institution's stakeholders about the principles we could use to understand stranded assets and the uncertainty mechanisms design one stakeholder felt we could do more to address assumptions in what we can deliver from the network given 'phases and losses'. They also added that investing in more expensive assets like low-voltage transformers could be helpful. [E152]

	• When asking stakeholders how can we identify the best opportunities for delivering value one stakeholder felt a potential challenge is a capability within SSEN and its supply chain partners to assess the specifications of the solutions provided by the supply chain.; "There are many new skills required here. So, how do you go about managing the nuts and bolts around managing uncertainty and uncertainty associated with uncertainty"?
National Government We engaged MPs and MSPs on our Draft Business Plan at an online consultation event	• The Scottish Islands UM seemed to be acceptable and stakeholders would like clarity on how Ofgem are planning to apply the UM and in what timeframe. [E151]
Stakeholder Advisory Panel (SAP) We ran an interactive engagement session with the SAP, inviting their input on the definition and design of our proposed additional UMs. This was an opportunity to test our proposals from a consumer value perspective.	• **Strategic Investment:** the SAP recognised the need for this UM across the ED sector, noting that the degree of use will vary across DNOs due to regional variations in LCT uptake and broader Net Zero transition. [E054] • **Wayleaves and Diversions**: the SAP recognised the uncertainty but questioned why we are not proposing a close-out mechanism to fund diversions (instead of a re-opener), like SHE Transmission. The SAP also questioned why diversions costs cannot go into the baseline plan. [E054] • **Shetland:** the SAP challenged us to more clearly outline the consumer case for SHEPD's transmission link contribution, articulating why a SHEPD to SHET transfer is in customers' interests (to avoid misperceptions). The SAP also urged that we make clear the two-sidedness of the Shetland UM package, allowing for downward adjustments if costs fall. [E054] • **Subsea Cables:** the SAP questioned why the costs of reactive/replacement works cannot go in the baseline plan, given our historic data on cable fault rates, and challenged how we would minimise the need to use the UM. We discussed how we have good data on cost per fault but volumes are too volatile to accurately predict, and will seek to better present this facet of the data in our business plan. [E054]
Wider stakeholder engagement (North and South region events) We ran collaborative engagement events for the North and South licence areas, with wider stakeholder representation from a range of organisations. This was a chance for us to communicate our proposals to both specialised and generalist audiences, providing opportunities to clarify and challenge our proposals from a range of perspectives.	• **Strategic Investment:** Stakeholders supported the UM, and the need for significant anticipatory investment, but expressed concern that a volume driver could lead to excess customer bill volatility if not designed carefully, given the significant investment required. [E092][E093] • **Wayleaves and Diversions**: Stakeholders echoed the SAP's views in questioning the merits of a re-opener mechanism over an end-of-period close-out mechanism and challenged us to clearly articulate the advantages of a UM. [E092][E093]

ENGAGEMENT STATISTICS	INSIGHTS	STAKEHOLDERS ENGAGED
13	90	1,641

STAKEHOLDER SEGMENTS ENGAGED

CONSUMERS	Domestic customers	Customers in vulnerable situations	Transient customers	Next generation bill payers	SMEs	Major energy users	
CUSTOMERS	Distributed generation customers	Builders and developers	Community energy schemes	Landowners/ farmers			
POLICY MAKERS AND INFLUENCERS	Government	Research bodies, policy forums and think tanks	Media	Consumer groups	Regulators		
COMMUNITIES AND LOCAL DECISION MAKERS	Local authorities	Charities	Academic institutions	Housing associations			
	Vulnerable customer representatives	LEPs	Emergency response	Healthcare	Community interest bodies		
WIDER INDUSTRY AND VALUE CHAIN	DNOs	Transmission	GDNs	Water	Telecoms	IDNOs	
	ICPs	Consultants	Energy suppliers	EV charging	Other supply chain	Storage and renewable providers/ installers	Transport and highways agencies
PARTNERS AND ENABLERS	Current and future employees	Contractors	Service partners	Shareholders	Investors	Business advisers	Trade unions

Evidence Assessment

ENGAGEMENT SCORING KEY

The engagement score assigns a weight to each source accounting for the robustness of the engagement event and the relevance of the feedback to the topic.

Overall score	Description
1-1.66	Limited evidence of good event planning, methodology or data collection. Feedback provided is high level with tangential relevance to the topic.
1.67-2.33	Good evidence of engagement planning and discussion of data collection methods, but limited depth of feedback and range of opinions. Feedback not necessarily fully aligned to the topic and only provides a limited insight and thus moderately useful.
2.34-3	Well conducted, trustworthy event with highly relevant feedback. Specific, clear and relevant information with clear link to the topic discussed and high value added.

Phase	Date	Event ID	Event name	Key stakeholder groups	Number of stakeholders engaged	Engagement score
Phase 4: Testing and Acceptance	Oct-21	E153	Employee Consultation Document Engagement on Draft Plan	Current and future employees	3	1.8
	Oct-21	E155	Stakeholder Consultation Document Engagement on Draft Plan	Community interest groups, storage and renewables suppliers, emergency response, healthcare and highways agencies	19	1.8
	Sep-21	E171	Engagement on Draft Connections Outputs	Housing associations, local authorities, community energy groups, distributed generation customers, consultants, ICPs and IDNOs	67	1.3
	Sep-21	E152	Academic Panel	Academic Institutions	7	3.0
	Sep-21	E170	Microsite survey on Costed outputs	Domestic Customers, Vulnerable Customers and Future Customers	1,298	1.7

	Sep-21	E176	Citizens Advice report on DNO Draft ED2 Business Plans	Consumer groups	1	2.0
	Sep-21	E151	Consolidated Outputs and Costings Event	Contractors, Consultants, Local Authorities, National Government, Storage and Renewables suppliers, Supply Chain	106	2.5
	Aug-21	E166	Corporate Affairs General Bilateral	Government, Storage and renewables providers	25	1.5
Phase 2: Co-creation	Dec-20	E054	Stakeholder advisory panel on uncertainty mechanisms	Current and future employees	14	2.2
	Mar-21	E068	UM South round table	Distributed generation customers, local authorities	10	3.0
	Apr-20	E084	Risk and uncertainty in the disrupted world (Sustainability First)	Research bodies, policy forums and think tanks	1	2.5
	Mar-21	E092	UM North round table	Consultants, ICPs	10	3.0
	Jan-21	E093	Supply chain survey: sustainable procurement	Other supply chain	80	2.0

Measurement of success

The decision on further stakeholder engagement on our application to use UMs during RIIO-ED2 remains with Ofgem. Stakeholder views will be sought on the application of particular UMs

SSEN DISTRIBUTION RIIO-ED2

DESIGN OF A STRATEGIC INVESTMENT UNCERTAINTY MECHANISM

RIIO-ED2 Business Plan,
Annex 17.1 (Appendix 17.1.1)

Scottish & Southern Electricity Networks

CONTENTS

1. CONTEXT

- It is agreed across industry that a Strategic Investment Uncertainty Mechanism is necessary to give the networks agility and protect consumers, given the dynamics of the energy systems transition to net zero
- We are putting forward our proposed design of the SI UM
- We propose Ofgem adopt this as the preferred model as part of ongoing industry discussions for resolution at the RIIO-ED2 Final Determination stage

One of the key issues for the ED2 period is there is an unprecedented amount of uncertainty for how quickly load will grow, driven by societal decarbonisation and where on the system this will create constraints. We believe that a Strategic Investment Uncertainty Mechanism (SI UM) is one of the keyways to address this issue. The SI UM aims to manage the risk associated with any gap between our best understanding of the system's future and the actual future that occurs in relation to 'load related expenditure'. This appendix is hence related to both ***Our Network as a Net Zero Enabler (Chapter 10)*** on load, and ***Uncertainty Mechanism (Chapter 17)*** on Uncertainty Mechanisms. This addresses where we need to enhance our system's power carrying capacity to allow demand to be drawn through our network, or in the unlikely circumstances where we do not need to release as much capacity as envisaged in our business plan, ratchet down our allowances.

How much we need to enhance that capacity, and where, is in part subject to considerable uncertainty beyond our control, particularly in the context of the journey to net zero. Whilst we have included a credible baseline plan proposal in ***Our Network as a Net Zero Enabler (Chapter 10)***, we know there remains uncertainty linked to policy and market drivers for net zero. The most important manifestations of this are the electrification of heat and transport, which we forecast will add significant load to our network, predominantly in the form of EV charge points and heat pumps. The critical sources of uncertainty are:

- Where these technologies will be deployed and when
- Exactly what impact these technologies will have on the requirement for additional power carrying capacity, driven by:
  - the co-incidence between when new technologies area used and existing network peak demand
- The rate of uptake, and the extent to which uptake clusters in specific parts of the system (and hence puts them under greater stress)

These create a broad range of credible expenditure requirements, varying from our baseline ask. These uncertain requirements relate to activities captured in the Business Plan Data Tables C2, CV1, CV2, CV3, and CV4- although these tables capture the baseline funding request only.

In ED1, a re-opener mechanism served the function of mitigating this uncertainty, wherein if expenditure was out-with a calibrated 'dead-band' this would automatically trigger a review of funding by Ofgem, mid-way or at the end of ED1. This mechanism has had limited use so far and whilst companies will consider its application for ED1 close out it is clear the principle of its design is not suitable for the faster paced and more uncertain environment of ED2. In our view a more agile, automatic, and responsive approach is needed to protect consumers against uncertainty and the risk of unjustified under or overspend against allowances. Ofgem also recognise this need and have set out their views on the need for a volume driver based uncertainty mechanism through the Sector Specific Methodology Decision, and will be developing the UM with the support of the DNOs and other stakeholders ahead of draft and final determinations. Here we set out our view of how a complete mechanism should be designed and calibrated to support that process.

It is also important to view delivering investment in the context of achieving net zero (i.e. the overall amount of work we need to do on the network to deliver decarbonization) and deliverability (we need a steady programme of work to ensure that the work we do ourselves and that we contract out to our suppliers is orderly and efficient). As addressed in ***Ensuring Deliverability and a Resilient Workforce (Chapter 16)*** one of the key challenges for ED2 is building capacity within SSEN and its supply chain fast enough to keep up with anticipated demand for new connections and general load growth.

Taking this context into consideration, there is a clear need for a new load related uncertainty mechanism which can respond to these challenges in ED2, in a way the existing mechanism cannot. This document sets out our criteria for an effective mechanism, and the design we propose for ED2.

2. OUR CORE APPROACH AND CRITERIA

Key criteria for Strategic Investment Uncertainty Mechanism

Manages uncertainty

- Appropriately balances the risk around demand forecasting between us and consumers

Facilitate net zero:

- The UM should facilitate the timely release of capacity to ensure that the overall system can keep pace with increases in demand for electricity, particularly around
- The UM should enable early investment in the network, where there is a strong case to do so
- The UM design should focus on 'system' outcomes rather than 'network'- flexibility, whole systems and innovative solutions will all be at the forefront of our analysis as we apply this UM
- The UM should have a low regulatory burden, enabling the quick release of additional funding to meet system needs

Protect customers:

- The UM should protect against over-investment in the network, which leads to 'gold platting' and/or stranded assets
- The UM should encourage the use of lower cost non-network solutions to provide capacity
- The unit cost for the UM volume driver should be set in a way which drives efficient outcomes for consumers

Stakeholder led

- The UM needs to be supported by stakeholders, as an appropriate way to manage the risks around demand forecasting
- The UM needs to be able to allow stakeholders to shape the load plan within the RIIO-ED2 period

Aligns with other regulatory mechanisms

- The UM must work alongside other regulatory mechanisms

Managing Uncertainty

As outlined in Section 1, there is considerable uncertainty around how quickly (or slowly) load will grow in ED1 and how this translates into the need to intervene on the network. Our high-level approach has been to adopt a baseline allowance which includes sufficient spend in first two years of ED2 to ensure that all credible decarbonisation pathways out to 2050 can be delivered.

Table 1 below highlights the range of spend against different DFES scenarios. Our baseline allowances are close to the lowest credible spend to keep up with consumers needs for network capacity, based on our core DFES.

Table 1- forecast range of load related uncertainty

Expected spend range	Load Related Expenditure (£m)	Scenario this expenditure meets
Baseline (ex-ante request)	297.9	System Transformation & years 1 & 2 of Consumer Transformation
Upper end	538.2	Consumer Transformation
Lower end	267.7	System Transformation only*
Maximum positive variance from baseline	**240.3**	
Maximum negative variance from baseline	**(30.3)**	

*In in years 1 & 2 we will spend more than ST requires to guarantee we could meet a CT scenario. If ST outturns, we may be able to reduce the planned baseline years 3-5 spend, depending on efficiency opportunities

However, our baseline allowances do not include sufficient spend to meet the more aggressive forecasts within the ED2 period. We therefore need to be sure that the means for accessing further funding, should capacity needs be greater than the baseline requirements (which we view as likely to happen), are sufficiently agile.

The consequences of not keeping up with demand for capacity are serious; either causing our network to become overloaded and posing a reliability risk or delaying new connections and LCT uptake – this would not be acceptable from a consumer perspective and would delay the facilitation of net zero.

It is also possible (though we consider it unlikely) for the real-world requirements that outturn to be less than our baseline view; in such a case, we'd propose that the UM should have a symmetrical design such that the related allowances would be returned to consumers.

It should be noted that the definition of load related spend applied by Ofgem for the purpose of ED2 reporting includes expenditure on flexibility services we might procure. Therefore, the need for a UM is not just linked to network asset investment it is also required so we can continue to facilitate our flexibility first commitments.

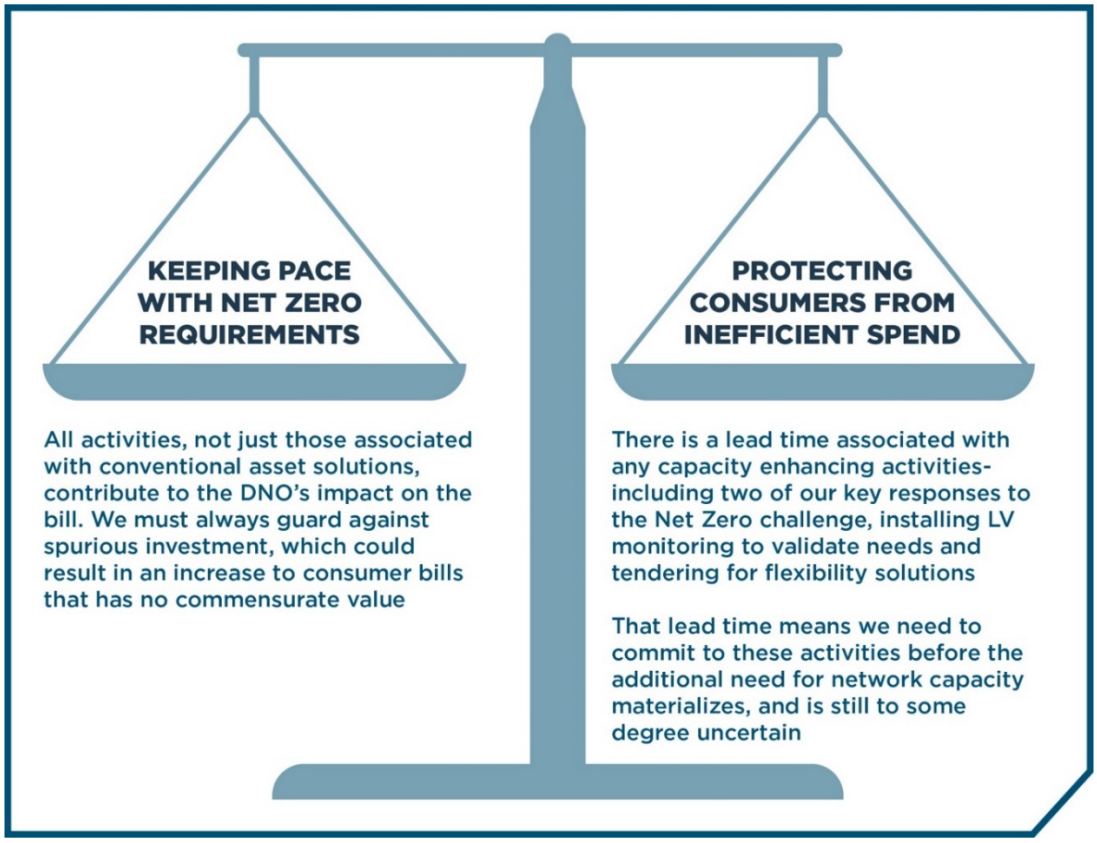


Figure 1- The key trade off in load related spend

3. SUMMARY SOLUTION

- Expenditure is triggered by our annual planning cycle which is transparent, and stakeholder led; each year of ED2 we will update our plan for the following years where we are triggering certain works (including flexible solutions)
- The planning cycle includes: (1) the stakeholder led DFES, (2) technical network assessments, and (3) economic network assessments. Each step has an associated transparent, published methodology
- Expenditure is based on where this cycle identifies requirements for intervention within a short time horizon, **or** where anticipatory investment is needed due to the deliverability of longer-term requirements, **or** where more efficient work packages can be created through advancing interventions for some requirements
- These efficient work packages can be driven by a range of potential synergies: whole systems options, network access being facilitated by another driver, or multiple requirements at the same site, for example
- We will generate standardized evidence on our interventions to demonstrate we've considered the right range of options, at the right time, based on the best forecasts, and selected the options that maximise consumer value
- We will thus maximise consumer value by stating ahead of delivery, for non-baseline interventions, how we will balance the risk of anticipatory investment against the need to keep pace with LCT uptake
- Where DNOs do not follow the methodologies, they set out, Ofgem can leverage existing regulatory tools to disqualify relevant allowances
- Ofgem's role can be minimal, but with the ability to intervene each year following reporting of volumes
- We present our best view of the what the UCAs should be, based on our forecast ED2 costs, in section 7

We propose a symmetrical volume-based driver mechanism, based on MVAs of capacity and kilometres of circuit delivered. The mechanism would work as per the flow diagram below:

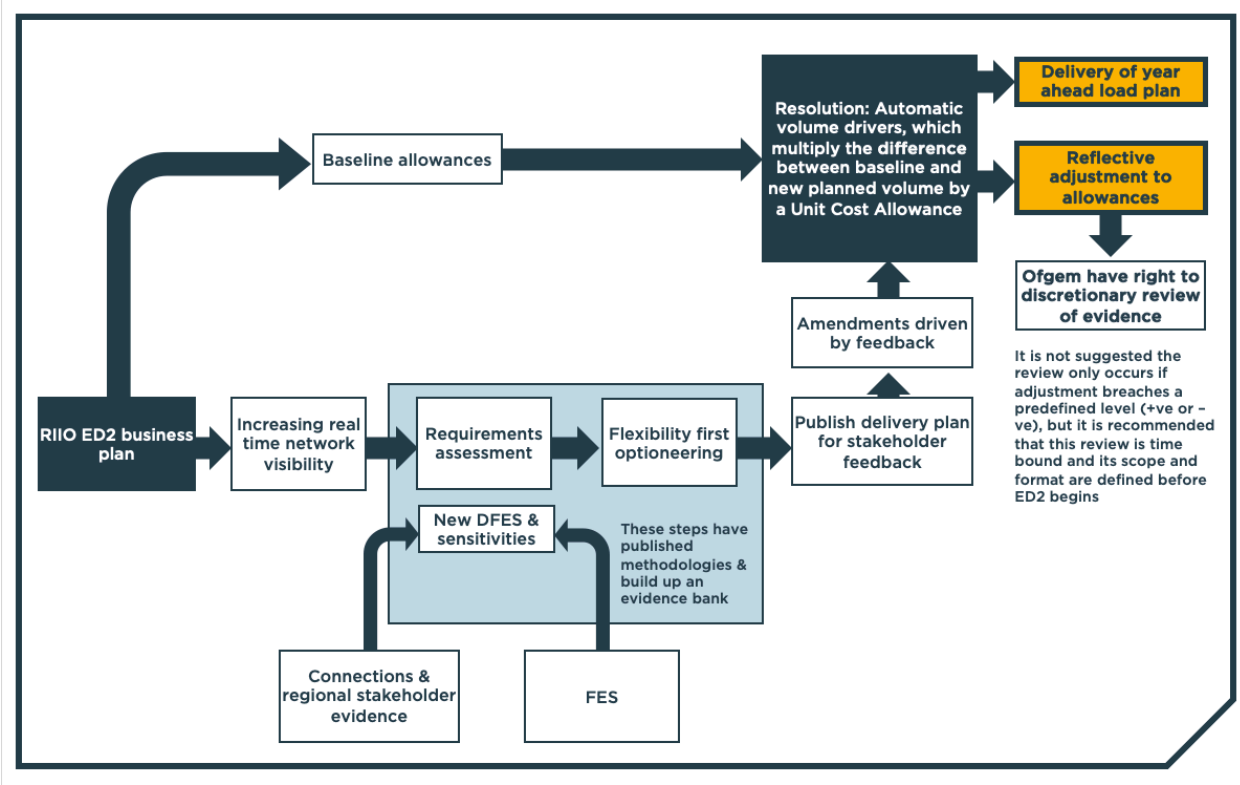


Figure 2- Simplified overview of SI UM operation

Operation of this mechanism would ultimately support our stakeholders by providing network capacity in the right place at the right time with a commensurate adjustment to allowances. Figure 3 is an alternative representation of Figure 2 focussed on funding, which shows how the DNO can access funds from the start of the delivery year, but also commit to those works in their submission such that work is agile but the DNO is accountable. This makes the mechanism truly forward looking, facilitating the kind of agility required for net zero uptake.

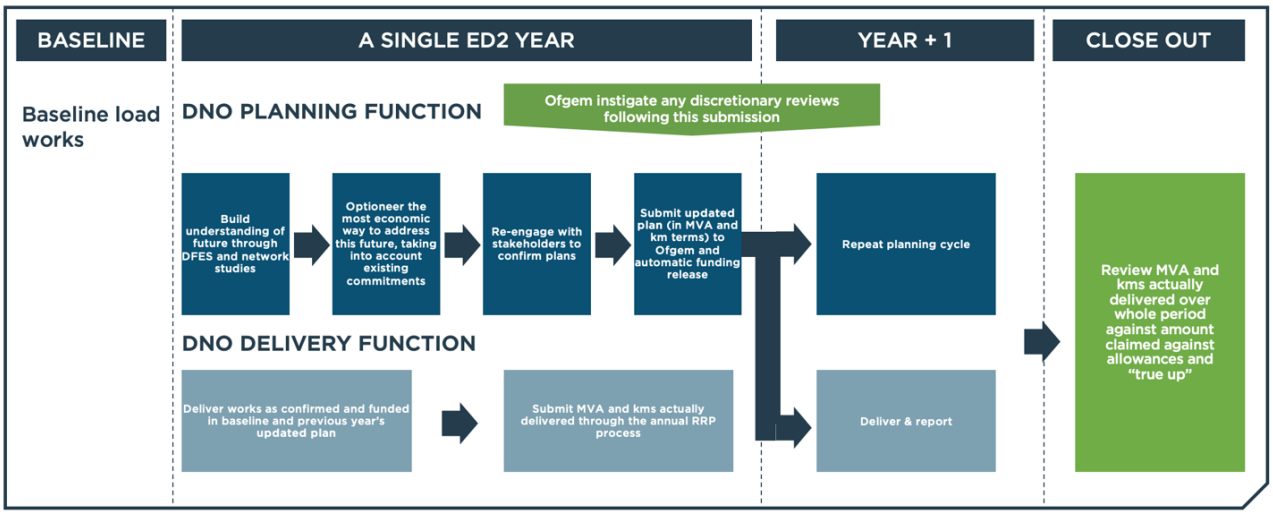


Figure 3- forward looking funding arrangements

To minimise regulatory burden and give DNOs the flexibility to deal with unforeseen circumstances, we propose all 5 years of the regulatory period are then subject to a "True up" at close out rather than more frequently. This would hold the DNO accountable for the allowances actually claimed. Allowances released vary by MVAs or kms delivered, so any error remaining at the end of the regulatory period would be subject to a final adjustment (while taking account of funding for works that cross into ED3).

Examples use case (illustrative)- ED2 year 2

Divergence from forecasts

Our existing forecasts for a particular housing estate did not capture a strong interest within that community in electric vehicles and heat pumps, driven by local factors. Our existing forecasts for the area, indicated that reinforcement would likely be required in ED3.

However, in ED2 year 2, our stakeholder engagement through the DFES process revealed high ambition from the local council and private homeowners in the area to convert to electric heat and vehicles. Our network visibility work (using smart metering data and predictive analytics) confirmed this, with load rising faster than forecast. The combination of latest load data and updated DFES indicates that a local transformer will become overloaded in year 4 of ED2.

Our response

Having found this updated network requirement, we then activated our LV monitoring strategy to provide additional certainty on need and tested the market for flexibility within the area. This resulted in us confirming that the transformer would be overloaded by 500kW within 2 years. We test the market for this capacity but are unable to find flexibility.

Using the Strategic Investment UM to fund required interventions

We produce an updated load plan for year 4 of ED2, which is tested with stakeholders. This includes reinforcement to release 2MVA of capacity (the most appropriate size asset to manage longer term growth). This 2MVA is multiplied by the agreed unit cost to provide an increase to our load allowance for year 4 of ED2, in order to fund the work and facilitate the EV and heat pump connections.

To arrive at this solution, we developed a four-cornerstone approach to set out the principles that guided us in Figure 4 below. In the remaining sections of this document, we describe the approach that we've taken to arrive at the summary solution, structured around these four principles.

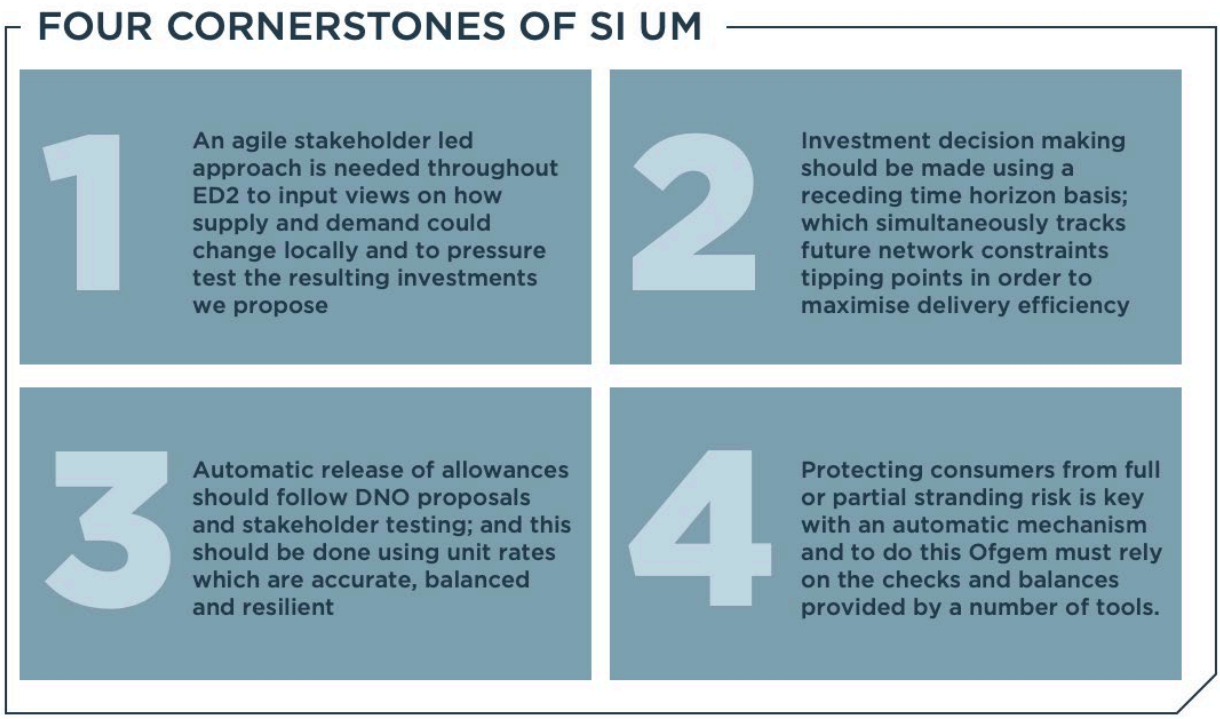


Figure 4- Four cornerstones of the mechanism

1. **The use of stakeholder led processes to continually update our best view of the future as new information appears**

The DFES process, which is standardized across the DNOs, takes the nationally recognized National Grid ESO FES and adds another layer of geographical granularity based upon the DNO and their own stakeholders' extensive and detailed knowledge of their own regions. An additional source of requirements is the connections process, again driven by stakeholders.

2. **Our view of requirements is continually tested and updated, and the best decisions are made at the best time, including consideration of whole system, geographic and time-based efficiencies**

We propose to standardize publication of 2 methodologies (in addition to the DFES methodology); firstly, a description of how we use scenarios to derive system requirements (through use of power systems studies techniques and interpretation of the network codes and standards), and secondly how we then optioneer and select solutions to meet these requirements (techno-economic assessments that encompass **all** options across flexibility, whole systems, innovation and conventional). These requirements could be met by existing publications, such as the Long-Term Development Statement, or be additional standalone documents.

We propose that a core principle of this UM is that of investing at the right time. this means intervening as soon as a requirement **could** be challenged by lead times in **any** credible scenario- so if a scenario suggests we need to act immediately to

avoid compliance issues, we must act. We should however defer decisions where lead times allow us to wait a planning year for more information. The mechanism should also allow for activities that do not meet this criteria if benefits can be demonstrated from advancing work packages. The synergies this could include could be deliverability based (by reducing the workload in a future year, the work can be delivered more economically), geography based (there are multiple requirements at the same substation, and it would be more effective to deliver them all at once), or whole systems based (another energy vector can achieve a substantial benefit if DNO activities are delivered sooner).

Increasing network visibility is a key part of our ED2 vision. Deployment of additional monitoring ahead of investment to remove risk is a core part of our process, by reducing the uncertainty in our expenditure decisions; hence wherever practical we will measure and analyse real network loading before deploying solutions. These solutions will be chosen from our full range of options, respecting the flexibility first principle used to develop our ED2 proposals and leveraging whole system and innovation opportunities wherever economic. This will be a key component of a valid claim of allowances through the volume driver.

3. **A carefully tuned set of Unit Cost Allowances and a means of applying them that delivers allowances that match costs with high accuracy**

Unit Cost Allowances apply across all relevant activities, so include both conventional reinforcement and flexibility approaches. They are set at the start of the period, and fixed; this maintains the DNOs incentive to continue to find lower cost ways of meeting requirements. They should be found through regression type models of real costings for ED2 load related activities, and those models in turn should be rigorously tested to give confidence that the figures are robust.

4. **A requirement for rigorous and standardized evidencing that transparent methodologies have been followed and stakeholders have helped build the plans, alongside Ofgem's discretionary right to review plans in period, provides protection for consumers from excessive bills**

In this mechanism, consumer value is protected largely through robust and transparent methodologies, and a bank of evidence being produced by DNOs to show these have been followed. Core pieces of evidence include metrics such as Load Indices for assets being intervened on, and CBA tools deployed such as the Common Evaluation Methodology tool.

To achieve the balance of a low regulatory burden against maintaining consumer protection against inefficient spend, it is proposed that Ofgem do not need to, but have the ability to, view and challenge the evidence supporting load related expenditure following the submission of the regulatory reporting packs each year. It is suggested that a 2-month window for challenge, and a formalized process around how load spend specifically is challenged, is introduced alongside this mechanism.

We believe by following this robust process we will ensure all of our spend is optimized to deliver what consumers need, on time.

HOW THIS SOLUTION ADDRESSES REQUIREMENTS OF A UM AS SET OUT IN OFGEM'S BUSINESS PLAN GUIDANCE MINIMUM REQUIREMENT

The following briefly outlines how the solution addresses the key factors for UMs identified in the Business Plan Guidance- more justification and detail on each point is contained in the following sections, signposted as appropriate below.

a. Issues and risks that the proposed mechanism addresses

Whilst there is a clear need for substantial Strategic Investment, there remains significant uncertainty over the volume, timing, location, and type of investment required. The need for additional network capacity will be driven by a range of factors, including key trends outside of our control such as the development and uptake of LCTs, consumer behaviour and new government legislation. As Ofgem rightly acknowledges in the RIIO-ED2 SSMD, DNOs must strike a careful balance between investing proactively enough to support rising demand and prevent system overload, whilst also investing efficiently and minimising the risk of stranded assets. DNOs should also minimise bill increases for consumers, ensuring that costly reinforcement of the network is only applied when alternative options, such as use of market-based flexibility services, are insufficient to meet consumers' current and future needs.

Recognising these important trade-offs and the need to provide flexibility over RIIO-ED2 investment (as the net zero transition evolves), Ofgem's RIIO-ED2 SSMD proposes an UM for Strategic Investment, as well as a separate net zero re-opener mechanism to cover impacts from new net zero targets or legislation (or other related developments). We welcome both of these proposals, and we are continuing to engage with Ofgem on their design and parameters. We consider a key difference between the Strategic Investment UM and the net zero UM to be the nature of their impacts on investment. We envisage the Strategic Investment UM to cover incremental changes (including potentially large changes) in load-related investment as needed to deliver additional network capacity, whereas the net zero re-opener will cover new net zero targets or legislative decisions (or other related developments) that necessitate a quantum change on our costs and outputs (including but not limited to load-related investment).

b. The design of the proposed mechanism

In line with Ofgem's RIIO-ED2 SSMD, we are proposing a volume driver mechanism which will adjust cost allowances based on the net capacity delivered by load-related investments in each year. We consider that the mechanism should provide for annual allowance adjustments, based on pre-agreed unit costs. The full detail of our design is outlined in sections 6-10 of this document.

c. Ownership of risk under the mechanism

Our proposed volume driver will result in risks being shared between us and our customers. Should we deliver less capacity or circuit length than we've set out in our baseline plan, the mechanism would facilitate for the return of allowances to customers. Equally, however, there may be a need for additional investment over RIIO-ED2 to deliver the required network capacity, then customers will contribute towards the cost of this. Our baseline proposals focus on high certainty works (that is, those needed in the least aggressive scenario considered) as well as works that avoid foreclosing our most aggressive credible scenario. This approach minimises the risk that any baseline funded assets could be stranded, protecting consumers.

We will bear the risk that outturn unit costs are higher than our unit cost allowances. This risk is also two-sided, in that we will benefit should we achieve cost efficiencies relative to our unit cost allowances.

We consider that this balance of risk is appropriate and aligned to customers' interests. Given the challenges in forecasting the level of investment required, and the magnitude of this investment, it is important that we have the financial flexibility to deliver the optimal level of additional network capacity over RIIO-ED2. Any delays in delivering this investment could not only weaken customer service (increasing the risk of system overload and power outages), but impede GB's decarbonisation journey, creating substantial costs for wider society. The flexibility provided by the volume driver will enable us to invest efficiently based on customers' evolving needs.

The proposed approach to unit costs further strengthens the incentives for us to deliver additional network capacity efficiently, creating opportunities for economies of scale.

d. Materiality of issue

Our proposed volume driver for Strategic Investment will cover fluctuations in investment relative to the RIIO-ED2 baseline plan (on an annual basis). To estimate the cost uncertainty range associated with this volume driver, we have therefore calculated the maximum projected underspend and overspend relative to the baseline, based entirely on the DFES 2020 scenarios. Applying this approach, we derive an expenditure range of £268m to £538m across our two licence areas combined, relative to a baseline of £298m (equivalently, the potential variance from the baseline is -£30m to +£240m). This breaks down as follows across our licence areas:

- For SEPD, the expenditure range is £206m to £409m relative to a baseline of £227m (equivalently, the potential variance from the baseline is -£21m to +£182m).

- For SHEPD, the expenditure range is £62m to £129m relative to a baseline of £71m (equivalently, the potential variance from the baseline is -£9m to +£58m).

e. Frequency and probability of issue

The proposed volume driver will have an annual application, fed by our stakeholder engagement and annual planning process.

The probability of the mechanism being applied is high, given the highly uncertain nature of issues such as LCT uptake and consumer behaviour, and the fact that only small deviations from baseline volume forecasts could potentially necessitate application of the mechanism (although as noted above, we would be willing to discuss the use of deadbands with Ofgem and other DNOs).

In addition to the above, we recognise that there needs to be transparency over DNOs' load-related investment decisions, to provide the required assurance that any additional investment undertaken is necessary and efficient. We consider that the Strategic Investment volume driver needs to be accompanied by a clear trigger which is consistent across all DNOs and externally transparent, which is discussed in section 5, 6 and 7.

f. Justifications for the proposed mechanism

Our justification for each aspect of our proposed UM design is detailed throughout the remainder of the annex.

g. Drawbacks of the proposed mechanism and mitigations

We recognise that the combination of volume driver parameters and supporting processes which collectively make up the Strategic Investment UM creates complexity, and there is a risk that such complexity could dilute transparency and accessibility for broader stakeholders. This is an important consideration, given the consumer interest in our contribution to net zero. We intend to work closely with Ofgem and other DNOs over the coming months to ensure that our final mechanism design is sufficiently straightforward and transparent for our stakeholders, recognising that key aspects of the UM including unit cost allowances design are subject to ongoing discussion with Ofgem and other DNOs.

A more specific potential drawback of the mechanism is the challenge involved in setting accurate unit costs. There is an important balance to strike between simplicity and granularity when developing unit cost allowances, with a need to avoid allowances which are either a weak proxy for outturn costs or very complex to administer.

To ensure we get this balance right, there should be some flexibility over how granular our unit cost allowances can be, allowing for distinctions across various cost dimensions (such as asset type or voltage level), rather than mandating a one-size-fits-all approach. Providing this flexibility will enable DNOs to employ established analytical techniques that assess the case for different unit cost designs and identify those that strike the best balance between simplicity and granularity. We consider that such techniques could include econometric and Monte-Carlo modelling of relationships between project-level delivery costs and various explanatory variables (such as new capacity delivered or asset lengths), to ascertain which relationships are the strongest and most consistent (thereby reducing the likelihood of windfall profits or losses being incurred).
Such analysis could be used to design and calibrate unit cost allowances, and it could potentially incorporate both outturn ED1 data and forward-looking RIIO-ED2 data for a rounded view.

The most critical drawback is the concern that a volume driver could be used significantly more than forecast and result in DNO's claiming excessive allowances, impacting consumer bills.

This is ideally mitigated by the robust application of forecasting and decision making that means each use of the mechanism is very well justified, and Ofgem's annual right to challenge that evidence would hold DNO's to account for only delivering activities that serve the consumer's interest. However, additional measures such as an automatic 'tramline' trigger for a re-opener if allowances breach a certain rate could be combined with this proposal to provide an additional layer of protection for consumers.

h. Value for money for consumers

We consider that our proposed mechanism offers value for money in several ways.

Firstly, our mechanism provides value through its flexibility. As noted above, it is challenging to forecast how much investment will be required over RIIO-ED2, with deviations from the baseline plan being very likely. In the absence of an UM, this would risk significant underspend or overspend against baseline allowances, which could negatively impact customer service (especially if it led to system overload) and/or result in customer bills being higher than required. Our mechanism addresses both of these issues, ensuring that outturn investment is sufficient to maintain high standards of customer service whilst keeping customer bills efficient (i.e. only as large as needed to support sustainably high service standards for current and future customers).

Secondly, our mechanism recognises the pivotal role DNOs must play in supporting the net zero transition. The adoption of a volume driver signals to our stakeholders that we are making a credible commitment to invest as required to support the decarbonisation of key industries. This arguably brings positive externalities for wider society (including consumers), in that it demonstrates the supporting infrastructure required for LCTs will be put in place, and this in turn will encourage consumers to play their support in decarbonising the economy. Given that the transition to net zero will be substantially driven by consumer behaviour change, it is highly important that consumers have confidence that DNOs (and other energy network companies) are playing their part and supporting this behaviour change. Achieving this will ultimately support the cost-effective delivery of net zero emissions across wider society.

- What we've heard from stakeholders has driven our criteria for a good UM, and we will continue to act on this- not being a blocker to Net Zero is a key objective
- Our DFES process starts from the FES to ensure comparability, but then applies local stakeholder input to co-create the future
- While some developments were not in DFES 2020, they may emerge as key developments in next year's DFES- illustrating the need for a cyclical process that updates our view of network requirements as the system changes
- This process includes our leading work on understanding the impact of Energy Efficiency and Access SCR
- Our network visibility strategy is also always improving our world view

4. WORKING WITH STAKEHOLDERS TO UNDERSTAND THE FUTURE

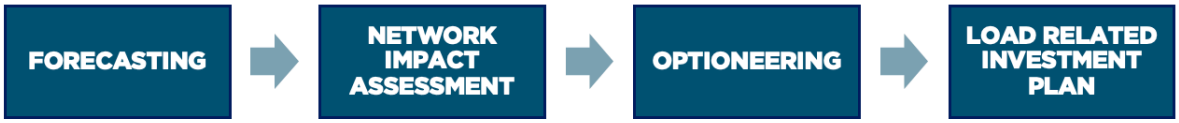
Stakeholders have had a far stronger voice in shaping our ED2 Business Plan than ever before. Our programme of inclusive, insightful, impactful, and iterative enhanced engagement has enabled our stakeholders, customers, and consumers to co-create the Business Plan with us.

The Enhanced Engagement Appendix to the ***Uncertainty Mechanism (Annex 17.1)*** demonstrates the golden thread that connects stakeholder opinion to the outputs we will deliver during ED2. It begins with a synthesised list of the actionable insights we gained about UMs, and how these have been implemented in the Business Plan. The sources of this evidence are scored for robustness, and the insights 'triangulated' against each other, which allowed output owners to trade off dissenting views and ensured that the most robust feedback had the greatest impact on the content of the Business Plan.

The stakeholder input to Strategic Investment specifically recognised the need for this UM across the ED sector, noting that the degree of use will vary across DNOs due to regional variations in LCT uptake and broader Net Zero transition driver. Stakeholders support the need for significant anticipatory investment due to the imperatives created by net zero but expressed concern that a volume driver could lead to excess customer bill volatility if not designed carefully, given the significant investment required, and raised the point that a capacity-based volume driver could lead to excess customer bill volatility if not designed carefully, given the significant investment required. We are working closely with Ofgem and other DNOs on several potential mechanism designs, with a focus on how consumers are protected; we believe this can be achieved through rigorous and robust decision making, combined with Ofgem having the right to review volumes claimed each year. We welcome the continued involvement of stakeholders as the Ofgem Working Group proceeds towards a final design.

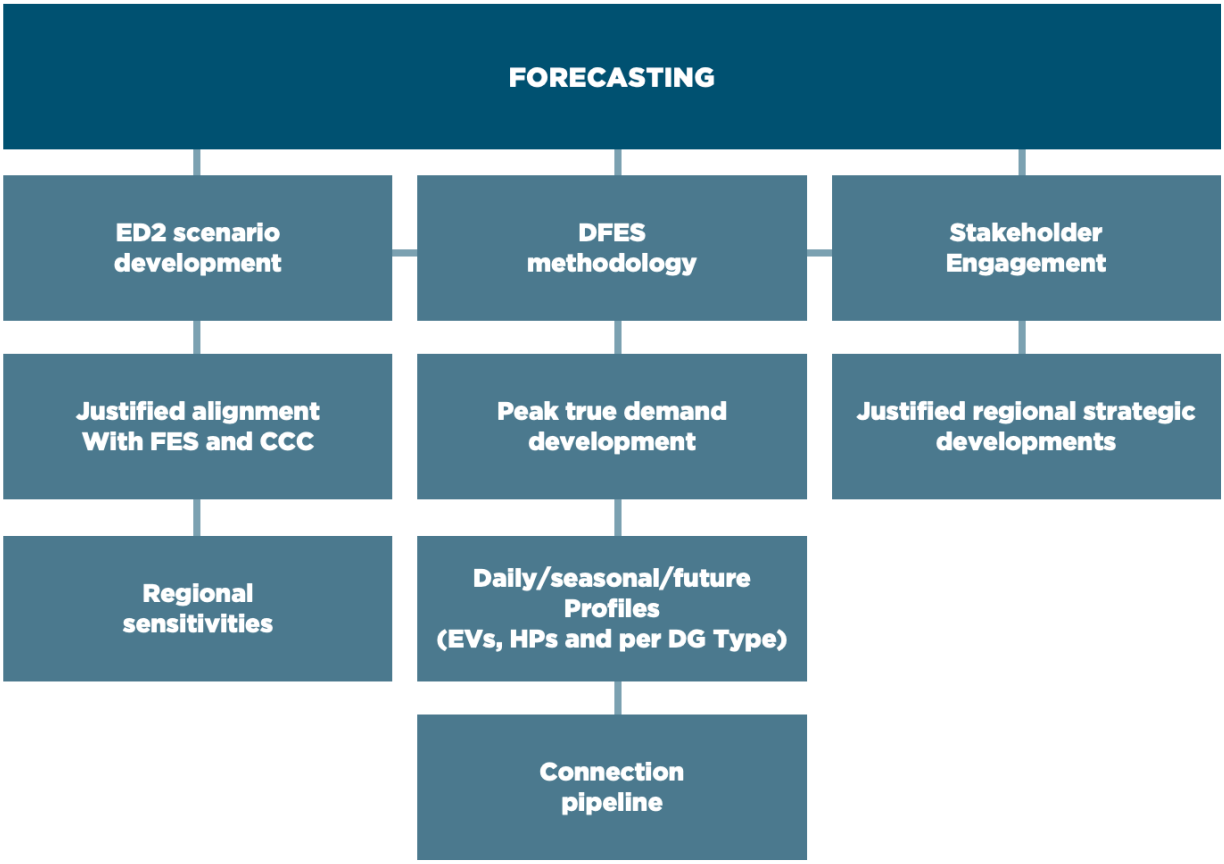
Forecasting: Co-creating the future through the stakeholder led DFES

A simple way of understanding load related planning is the 3-step process, as shown in Ofgem's conception within the Business Planning Guidance, see figure 3-3. This process applies not just to the ED2 business plan, but also to how DNOs plan deviations from the business plan within the ED2 period. The uncertainty within our load related activities is driven by the forecasting stage of load related investment planning, wherein changes to demand and supply characteristics are predicted. The rules that govern when the network will or won't be compliant are much more certain, as these are primarily driven by the physics. These rules *can* still change, but these core network codes that define compliance (ESQCR and P2/7 primarily) evolve slowly and with cross industry input. Therefore, the uncertainty mechanism is closely dependent upon the outcomes of the DFES process; although the actual trigger of investment or other interventions comes from the engineering analysis of the impact of these scenarios, it is the input uncertainty that drives the potential variation in expenditure.



All DNOs now use DFES as part of their planning activities and base them on the national FES; it is thus an area where standardization, transparency and comparability of outcomes are possible. The additional granularity and regional accuracy added to the FES by the DNOs, through various stakeholder activities and detailed network knowledge, enhances the quality of the forecasts, is key to allowing them to work as useful distribution network planning tools. A key additional standardization is the networks commitment to nominating their own 'central view' scenario each year (ie this is not the same across DNOs, but informed by their own stakeholders), which means investment needs can be understood across DNOs in a more consistent way.

As discussed in the ***Load related Plan Build & Strategy (Annex 10.1)***, we do significant, robust work with stakeholders to determine the most credible scenarios to assess our network against; it is important to do this on an annual basis, as the energy system is currently moving very quickly and local and regional plans for new generation and demand emerge frequently. Again, our view of how forecasting works is aligned with Ofgem's characterization of forecasting within the business planning guidance.



Maintaining a standardized and robust approach to forecasting

We have published the approach we have taken to DFES 2020 (the scenarios used in generating the ED2 submission), alongside details of the resulting scenarios[1]. Introducing region specific factors to a scenario do introduce divergence, and it is not recommended that DNOs are required to follow too rigidly proscribed a process; however, two key characteristics should be demonstrated by these methodologies.

1. A common starting point

DNOs should always be drawing upon the same national scenarios, to allow stakeholders to compare results by region. Moreover, the changes made to reflect the particular regional characteristics of networks should attempt to minimize how the aggregated national capacities of technologies change.

[1] https://www.ssen.co.uk/WorkArea/DownloadAsset.aspx?id=20283 & https://www.ssen.co.uk/WorkArea/DownloadAsset.aspx?id=20282

2. A standard approach to ensuring stakeholder evidence is robust

SSEN has used (and published within the DFES methodology document) a framework for assessing the evidence gathered to ensure the forecasts are influenced by high confidence information.

Working with stakeholders throughout ED2

Our ED2 baseline plans are based upon extensive stakeholder engagement designed to co-create the future. Submission of the plan does not mark the end of our stakeholder work, however; with an ongoing role for stakeholders in both how we create our scenarios **and** in challenging our use of the uncertainty mechanism in response to those scenarios (see Figure 2, box labelled "Publish delivery plan for stakeholder feedback"). Our ED2 baseline was constructed from scenarios developed in 2020- we know that these can evolve over time; for example, a key use case of how we may use this uncertainty mechanism in the ED2 period is on the Isle of Wight, where we will continue to work with local stakeholders to understand enduring investment requirements. Should growth in load or generation exceed our forecasts and to avoid system constraints from restricting local aspirations in achieving net zero, the uncertainty mechanism would enable us to invest in system upgrades in addition to those detailed within our plan.

A success story of ED2 was the Green Recovery mechanism; this model invited the networks to work with their local customers and stakeholders to identify a range of shovel-ready net zero related projects that could be brought forward and delivered under the existing price control for the sector. This mechanism had two features the Strategic Investment UM should emulate; it was truly stakeholder led, with a high level of engagement to develop the shortlisted projects, and it was agile, allowing timely release of funds that directly facilitated net zero outcomes. Stakeholder feedback was obtained by SSEN via an engagement campaign which included 2 general webinars, 41 individual stakeholder meetings and culminated in the industry-wide Call for Evidence which generated 152 submissions, identifying approximately 360 projects from 65 organisations across the SHEPD and SEPD regions- this demonstrates the power of effective engagement strategies, and should be echoed in ED2.

We hence see a potential ongoing role for the CEG, and a definite role for all our LAs in developing and validating our ongoing work; where and when we deliver network capacity should be challenged, as this directly drives the allowances we release and these will in turn impact consumer bills, and our stakeholders are well placed to demonstrate where load related interventions can be effective in delivering net zero outcomes, through both our scenario development phase and our delivery plan challenge phase.

- There's a lag between seeing requirements and delivering them that needs to be accounted for
- At LV we do sophisticated forecasting to reasonably estimate what assets have significant probability of being overloaded
- LV measurement produces a more certain picture, but only of today's conditions; we may still need to mobilise based on direction of travel
- At higher voltage levels we run studies to demonstrate how power flows drive compliance issues- this all takes time and needs to be targeted
- Planning on a receding time horizon is key to making low regret decisions- we get more information about the future as we move forward- flex and measurement important tools for buying time to gain extra information and remove risk from high value decisions
- As in our baseline plan, when using the UM for funding, we will still always consider all options- and put flexibility first wherever feasible
- We will use the ENA's CEM tool to make and evidence decisions, and recommend it is used as a standard across the networks
- This is supported by our internal rigorous cost challenging processes in the delivery phase
- We will generate a trusted, transparent, and standardized evidence base to prove we have followed our 'best decision at the best time' process
- To further transparency and be precise about intervention triggers, we will publish DFES and network assessment methodologies: one technical methodology for the power system studies, and one economic for how optioneering is conducted

5. THE RIGHT INVESTMENT AT THE RIGHT TIME

The right investment at the right time strikes the correct balance in the trade-off between delivering activities quickly enough and avoiding unnecessary expenditure. This is a trade off because:

- Activities take time to optioneer, design and execute- this lag must be accounted for when planning new activities to ensure solutions are in place in sufficient time to facilitate net zero related changes to energy usage
- The relevant activity drivers can evolve within these short time scales- so some decisions to act can be based on a scenario-based driver

- A scenario-based driver may not, by its very nature, materialize as expected; this means that money could be spent on something that there is not a clear, realized driver for. This could be due to, for example, new connections falling through

The ideal balance point is therefore to make the best decision possible at the point an activity and its actual commissioning coincides with meeting the earliest date it could be needed.

For example, if a substation is found to require an intervention in 4-7 years from today, depending on the planning scenario analysed, and it takes up to three years to optioneer, design, market test and deliver such an activity, then it is reasonable to wait one year to review the decision with updated forecasts. However, if the intervention is required in 2-5 years, more detailed work should commence. This is to mitigate the risk that the forecast driving a need of intervention within two years is the most accurate one. See figure 5 which shows a simplified view of this receding time horizon in practise.

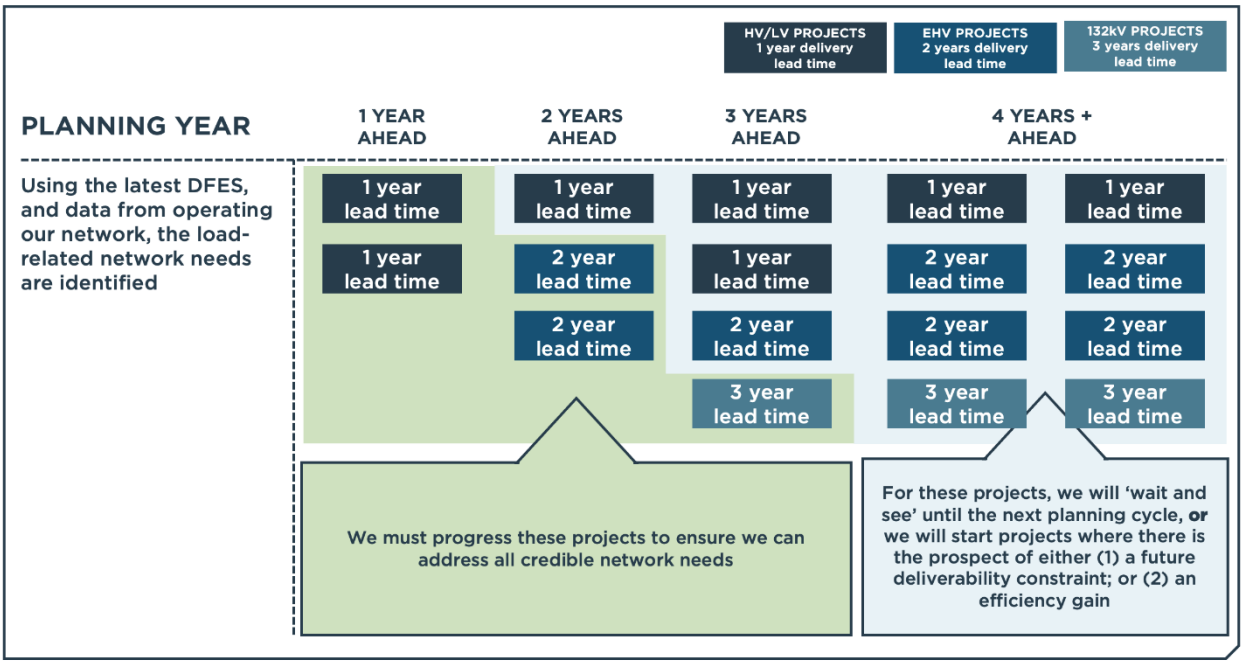


Figure 7- simplified view of receding time horizon planning

It is important to note that these 'time to deliver' rules are informed estimates; in reality a requirement may require a longer lead time due to project specific factors (for instance, submarine cable projects could easily be too complex for a three-year timeline). We propose to respect the principle that decisions to act are made when the time to deliver aligns to when any planning scenario shows a credible requirement. Time to deliver will not be immediately clear- and is different depending on the solution selected in the optioneering phase- so the longest credible time to deliver is the trigger for commencing the design and optioneering phase.

Longer term assessment to identify tipping points and efficient work packages

Whilst we take a receding time horizon approach to planning based on delivery time scales, the data we use to determine the size of constraint on the network must look long term for up to 10 years. If we don't do this, we risk multiple inefficient investments, with each one being rendered surplus in a short time period because a next tipping point has been reached requiring further investment.

To allow for this we propose that within each planning cycle we will look ahead at least 10 years to identify further tipping points at different points in the network. This will allow us to identify if it is efficient to size our investment requirements higher to manage future constraints and not just those we see in the short term.

An additional consideration beyond deliverability is that of 'efficient work packages'- if geographically linked requirements are discovered, but spread across future years, then it may drive significant value for consumers to deliver these as a single package of work, by bringing some investments forward. Efficient work packages also may mean consideration of non-load drivers; if a new asset replacement program is introduced for a type of fault, for example, then this requirement can also be considered in deriving efficient work packages funded by the mechanism.

Equally synergies can be found in the whole system space in the way unrelated projects are delivered, for example repairs to electricity and telecoms assets coordinating maintenance programmes could benefit consumers by reducing disruption. For related projects, it could mean establishing joint program governance structures, project specific ways of working and processes to share outputs and learnings with a wider set of stakeholders will all be critical in delivery of Whole Systems solutions. Should there be efficiencies that could be created by working with other utilities and local stakeholders, we will also fund these via the UM if a benefit to consumers can be demonstrated (for instance through reduced disruption). However, the **primary** driver of anything funded through the UM must always be load, and DNOs should set out in their network planning methodologies how their primary driver is defined.

It is expected that the longer-term deliverability and efficient work packages drivers will be defined in DNOs published network planning methodologies and evidenced in the same way as any other intervention- an efficient work package should drive demonstrable savings over meeting the requirements separately, so the standard of evidence, including CBAs, would remain.

Generating the evidence

Evidencing robust decision making is a key part of the regulatory deal; our baseline submission is underpinned by significant analysis and evidence, and this standard should be upheld in period to maintain transparency and protect consumers from unnecessary expenditure. This requirement is **not** in tension with the need for agility that drives the proposed volume driver structure of the mechanism; even where flexibility and urgency are required to support new low carbon loads, maintaining clear records of what drives our activities will always be key to responsible stewardship of the network.

The evidence requirement can draw upon existing CBA methodologies; these are already standard across the DNOs, for instance through the CBA template used in justifying baseline plans. CBA techniques are however still evolving in how they handle the comparison of flexibility schemes against other interventions. When options considered include both flexibility solutions and asset replacements, for example, complexity is introduced around what economic lifetimes you compare; while it is not difficult to resolve this in the context of a single CBA, a single consistent methodology across DNOs should be selected.

The ideal candidate for this is the Common Evaluation Methodology tool developed by the ENA:

- It has been produced by the ENA, thus DNOs already have a stake in this
- We have used this in our baseline submission, and it is an effective tool that is ready to use (but can continue to be developed through the ENA)

Other supporting documentation is also produced as standard as part of our internal governance processes, with increasing levels of scrutiny at higher bands of project capex. Key principles to be adhered to in optioneering process, and demonstrated in the evidence base (through an EJP paper that supports the relevant CBA/CEM):

- As wide a range of credible options as possible is considered, particularly flexibility
- Standard CBA practice is observed, such as is found in the ED2 CBA template
- Where key factors cannot be monetized, but create sufficient imperative to override the 'best NPV' or 'Least Worst Regret'[2] solution found mechanistically, this is robustly justified in the narrative; and every effort should be made to monetize all such factors robustly, with accompanying commentary on how this was performed
- Sensitivities should be included in justifications (to a level commensurate to the level of spend being considered) to show how robust the selected solution is to key input uncertainties; these should also be described and justified in the evidence base

Challenging the DNOs expenditure- regulatory burden versus adequate accountability

A barrier to an agile system, and DNO confidence to invest quickly enough in light of the net zero challenge, is the issue of how and when Ofgem probes load related expenditure when allowances are claimed.

Current regulatory incentives can make it more beneficial for networks to operate reactively, to manage the risk of suboptimal investment- infrastructure therefore can follow and tail demand. This needs to change as net zero related demand ramps up, significantly increasing the risk of insufficient infrastructure slowing the pace of LCT adoption.

[2] Least Worst Regret is a standard decision making tools in scenario based decision making, as deployed in the Networks Option Assessment- https://www.nationalgrideso.com/document/90851/downloadv

Networks need be incentivised to be proactive, so that much of the time the network is put in place anticipating and stimulating low carbon development. This would be a fundamental shift in approach.

In an environment where there is a meaningful increase in the level of anticipatory spending, accountability is more critical than ever to consumer protection. Ofgem must always have the ability to step in where it is in the interest of consumers; however, specifying the normal route for intervention ex-ante will help all stakeholders have confidence in use of the mechanism.

Under this design, allowances are claimed annually, where the regulatory reporting pack from each DNO sets out the volumes to be delivered against each intervention type that qualify for use of the SI UM. It is proposed that after this submission, a period is defined for Ofgem to review and decide if any DNO submissions necessitate opening a more thorough review. The trigger for such a review could be the volume of allowances claimed being above or below expectations; however, it could also be at Ofgem's discretion, if they feel a particular issue with a single intervention type warrants further scrutiny.

Should such a review be triggered, a standard process should then be formalized, including features such as notification of the DNO with the review trigger and requested information, a time to respond with the relevant evidence for the volumes claimed that year, and a range of decisions Ofgem can take if they find evidence insufficient for volumes claimed (as well as a right to appeal for DNOs). The full design of such a process is not presented here, rather noting that this would be an important consideration in a mechanism design like the one proposed here. This process would be at the heart of an agile mechanism, providing robust accountability, but also allowing the mechanism to run efficiently where allowances being claimed are within expectations, and giving DNOs confidence that any review of their plans would follow a predictable form and timetable.

6. PROTECTING CONSUMERS

- The baseline only includes funding for high certainty works
- This provides a protection against underspend compared to the baseline, however we should monitor this risk
- The use of the mechanism will be efficient through the application of robust and transparent methodologies
- Protecting consumers from unnecessary or too early investment, is a key objective of the regulatory environment
- There is a consensus that anticipatory investment is required in order to ensure that networks can support rapid decarbonization, and that inherently creates a risk of non-optimal utilization
- Stranding of assets is a difficult concept- particularly given utilization (i.e. peak loading relative to capacity) should decrease immediately following intervention
- Rigorous and transparent forecasting and planning processes, and standardized evidence supporting decision making, are our key tools to spend money efficiently
- Should we not meet these standards in ED2, Ofgem's existing toolkit allows for relevant and commensurate modifications to allowances

Protecting consumers from excessive costs, and from paying for activities that do not improve network performance, is a key goal of ED2 in general and this mechanism in particular.

Across both of our license areas, it is likely that our actual work undertaken throughout ED2 will not exactly align with our baseline plan; this is to be expected, as the described works in our business plan are based on forecasts with inherent uncertainty behind them. This proposed mechanism will address this in the load space by tying allowances to what is actually delivered. Our proposed volume driver will allow for the triggering of increased or reductions in allowances in response to the load on the system, which will be strongly influenced by how the development and uptake of LCTs progresses over ED2. We note that the four DFES 2020 scenarios differ significantly in this regard.

It is therefore proposed that delivering under the baseline level of activity will result in the use of the mechanism to determine the related reduction in annual allowances. This is a possibility if System Transformation unfolds- as we propose to fund works that would facilitate a Consumer Transformation world in years 1 & 2, should this scenario not outturn within ED2 we may then not require to do such extensive works in years 3 to 5. However, as System Transformation is our least aggressive 'credible' scenario, we view needing to spend above the baseline as a more likely outcome.

We are committed to protecting consumers from excessive bill impacts, and hence have set out:

- our rigorous criteria for using the uncertainty mechanism.
- our commitment to following transparent, stakeholder led processes.
- our robust optioneering process to deliver network capability at minimum cost, and
- a symmetric mechanism that protects against unspent allowances.

On top of these factors, however, there may still be the need for additional intervention to act as a final 'safety net' that means consumers do not bear excessive costs driven by unnecessary interventions (the term intervention is preferred to investment here; for example, costly flexibility contracts could still be a detriment to consumer value even where supplanting conventional reinforcement).

SSEN's view is that this 'safety net' can already be delivered via Ofgem's existing regulatory toolkit as detailed in the figure below.

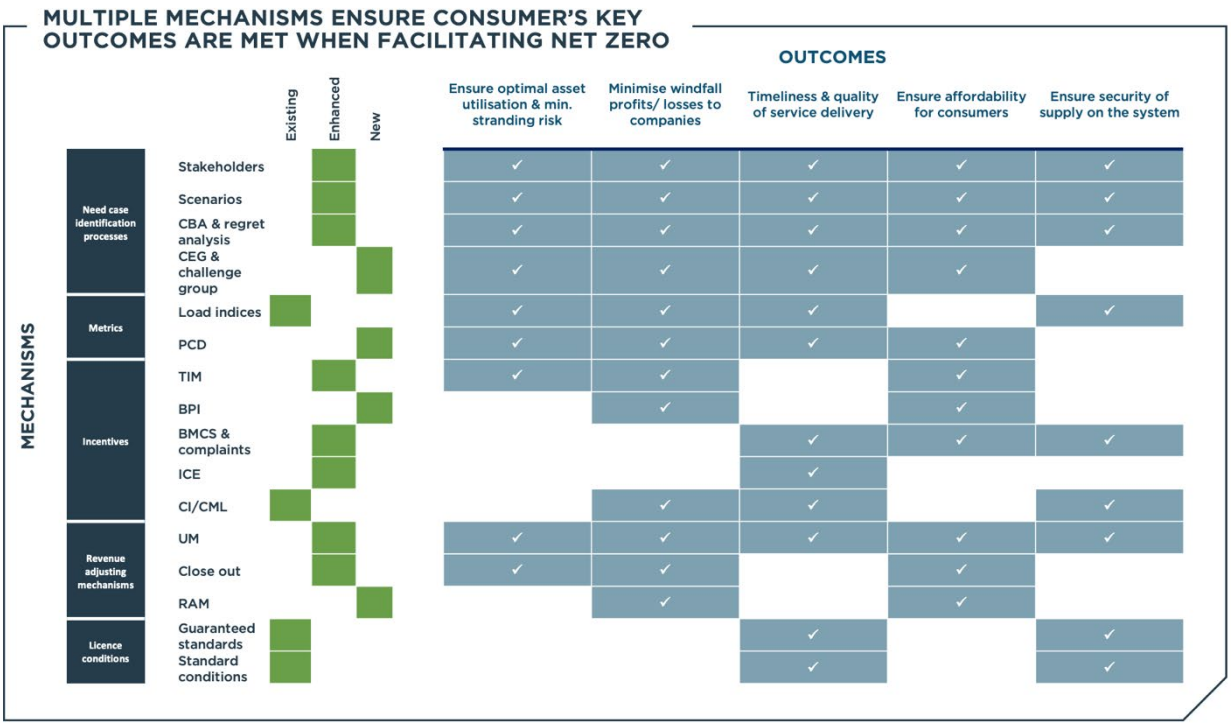


Figure 8- mechanisms to protect consumers

An additional mechanism could provide an extra layer of protection to consumers, which we would support- however design of such a safety net should be carefully considered to avoid some of the pitfalls described in the following discussion.

Asset stranding and utilization incentives

A key area of concern in the industry is that of unnecessary or too early investment; the nature of the Regulated Asset Base means that network investments, and their financing costs, are funded over a 45-year period by consumers. If these assets are not 'used and useful', under current arrangements that does not impact the RAB model- they are funded in the same way. The purpose of a utilization incentive, or alternative mechanisms, is to discourage investments that pose a risk of adding to the asset base without generating commensurate value.

Such incentives pivot on the definition of a stranded asset; or put another way, what is an appropriate level of utilization for a new asset (where the driver for investment is load related)? A pitfall of using the utilization metric is that investment reduces utilization, as utilization is relative to the nameplate capacity of the network components being replaced/supported with additional assets. If a transformer is experiencing loading in excess of its nameplate capacity, the typical course of action would be to either add a parallel transformer to share the load, or to replace the transformer with a larger capacity unit- in both cases overall utilization, as measured at this point in the network, reduces. This is well understood, and a simple example, but does not give an obvious answer as to what the appropriate loading is post-delivery.

A related key consideration is the typically low marginal cost of enhancing capacity in light of the net zero challenge. Load forecasting can extend to 2050, where loads are expected to be generally much higher. Enhancing an assets load carrying capability significantly can be relatively inexpensive compared to a more modest capacity increase- and indeed throughout our load plan and in our non-load asset plans we have sought to drive long term benefits for consumers by future proofing investments in this way for a low additional cost. However, this sensible long-term decision could be discouraged when viewed through the lens of a utilization metric- a larger uprating of capability will result in a lower utilization than a more modest increase that may not be "2050 ready".

The optimal way to assess how "used and useful" an asset would be at the end of its useful life- this is of course impractical, however following delivery it is possible to reassess performance against the latest information, which tells us what its new *anticipated* utilization is, at a point where more information about the future has been revealed than was available in the planning stage. This can tell us something useful about the robustness and credibility of the planning processes that delivered the asset.

7. APPROPRIATE UNIT COST ALLOWANCES

A critical aspect of this mechanism is setting out reliable and fair Unit Cost Allowances (UCAs), which link the allowances companies to receive for investment funded via the UM. Four key criteria these Unit Cost Allowances must meet (and the metrics selected that these should apply to) are:

- They must be based on measurable outputs that can be strongly correlated (either directly or through a simple mathematical transformation) with real project costs
- They relate outputs to costs in an accurate way that can be demonstrated to be resilient, repeatable, and not result in any extreme errors
- They are exhaustive in the activities they cover, relevant to LRE
- The outputs selected are practical to measure in a standard way

To meet these criteria, we propose MW of capacity released and km of circuit delivered, with consideration of whether the circuit is overhead or underground. We have thus used our own ED2 project portfolio, where costs have been carefully forecast for a range of specific projects, to test the correlation of MWs and kms to costs incurred and derive accurate relationships between outputs and costs that could form the core of the UM.

We have then gone on to test the effectiveness of this design through a Monte Carlo sensitivity test, to demonstrate that use of the UCA gives a reasonable set of allowances when applied to thousands of randomized project portfolios, demonstrating how confidence can be built that these selection of UCAs gives the right outcome for consumers and DNOs. This test methodology is fully explained in the appendix.

As outputs have a different relationship to costs in different geographies, due to factors like the logistics of serving our more remote communities in the North, it is recommended that this exercise would be repeated for all GB networks independently, to set costs that are fair and reflective for each network.

The optimal UCAs found by our methodology are shown in the following table: the appendix to this annex contains a report on how these were derived and tested.

Scope	Allowance	Fixed cost (regression intercept)[3]
Individual projects > £25m	A high value project, assessed separately	
Non-circuit schemes	SEPD: £[redacted] per MVA release SHEPD: £[redacted] per MVA release	None
OHL circuit	SEPD: £[redacted] per km SHEPD allowance = £[redacted] per km	SEPD: £[redacted] SHEPD: £[redacted]
UG circuit	SEPD allowance = £[redacted] per km SHEPD allowance = £[redacted] per km	SEPD: £[redacted] SHEPD: £[redacted]
Service unlooping	£[redacted] per job[4]	

Table 2- Best performing UCAs found in econometric analysis

8. SUMMARY- MECHANISM DESIGN AGAINST CRITERIA

We have undertaken a summary review of how the proposed mechanism design meets the design criteria set out in section 2.

Criteria	Meets criteria	How the mechanism meets criteria
Manages Uncertainty		
Appropriately balances the risk over the volume, timing and location of demand increases, between DNOs and consumers	✓	We propose a symmetrical volume driver which allows load allowances to move, each year, based on the actual loading of assets, our DFES and stakeholder engagement) and CBA analysis. This will provide flexibility for allowances to move up and down each year in accordance with need, rather than medium term forecasts included in the business plan.
Delivers net zero		
Allows for the timely release of capacity to ensure that system capacity keeps pace with demand	✓	The UM will enable us to adapt our forward-looking load plan each year, in line with latest forecasts and data. This will provide us with additional allowances to release capacity, where needed, in order to keep pace with load increases.

[3] The fixed cost would be applied once in years where the mechanism is used to do works additional to baseline

[4] The proposed Service unlooping comes from our current best view of unit costs, rather than an analysis of its link to any outputs. This is because service unlooping is a relatively simple activity that only impacts the customers on those services.

Allows DNOs to invest early where there is a strong case to do so		Where opportunities arise in ED2 to deliver capacity more economically, we will be able to assess these. Where a CBA supports it, we will be able to update our forward-looking load plan with new strategic initiatives, designed to facilitate net zero at lower cost.
Low regulatory burden to release additional funding		We propose an Automatic volume driver, so allowance's chance without any regulatory decision.
Protect customers		
Protects against over-investment in the network		We propose that allowances can only adjust upwards where there is clear evidence that assets are heavily loaded and/or where CBAs provide robust evidence that early intervention is economic under a range of future scenarios. All the evidence to support increases in allowances will be transparent and available for audit.
Robust unit costs for volume driver		We have undertaken a detailed exercise to ensure that unit cost are robust. First, we have set challenging costs for a range of different load activities based on industry performance. We have then run monte-Carlo analysis to assess the most optimal unit costs based on over 1000 variations of different projects and geographies. This ensures that the unit cost is efficient and drives the right behaviour across the range of load activities.
Facilitates use of flexibility as alternative to investment		We have a clear and transparent process for load planning which includes market testing all capacity requirements before committing to asset solutions. Any additional requirements in our load plan (to be funded through the uncertainty mechanism) will go through this process, before we finalise the plan, assess the total capacity to be released and access additional funding through the volume driver.
Stakeholder led		
Stakeholder influenced design		Our proposals have been through our CEG, Challenge Group and various other stakeholder groups. We have also particated in Ofgem's ED2 working groups where these mechanisms have been debated and discussed.
Stakeholder needs drive load allowances		Our proposal provides a clear route for stakeholders to continue to influence our load plan in ED2. Each year, their input will be included in our updated DFES which will inform our load plan for the remainder of the price control. In addition, we will provide stakeholders with opportunities to comment on our load plan each year before it is finalised.
Aligns with existing regulatory mechanisms		

Works alongside existing LRE mechanisms		The proposed mechanism aligns well with the load planning process run by our DSO. It fully supports the use of flexibility and provides opportunities to update the load plan and allowances where new opportunities for flexibility are found. The mechanisms builds on historic data sets around £/MVa and £/km which have been reported to Ofgem for several years. It also allows us to move away from the blunt +20%/-20% load-related reopener which is not sufficiently agile to manage load uncertainty in ED2.

APPENDIX: DETAILED STRUCTURE, QA AND RESULTS FROM ECONOMETRIC MODEL

CONTEXT

A key principle of the proposed volume driver is that allowances are linked to outputs that deliver value for consumers who use our networks. This is achieved through 'unit cost allowances'- the quantified outputs selected are then delivered to a given level by the DNO, which then receives an increase in their allowance per unit of output delivered. For the mechanism to work effectively and fairly, the unit cost allowance should reflect as closely as possible the actual cost incurred to deliver the selected outputs.

For a variety of reasons, the actual cost per unit output is not stable (***regardless of output selected***; actual costs are driven by project specific 'inputs')- for instance, the cost to deliver a kilometre of circuit will vary significantly across different geographies which may drive variance in accessibility, logistical costs or labour availability. The mechanism is therefore founded on the understanding that an allowance per unit of output will **not** exactly match the costs incurred to deliver the outputs on a project-by-project basis. However, the calibration of these Unit Cost Allowances should strive to achieve as close a match as possible between allowances for outputs and the DNO costs needed to deliver these. Importantly for the mechanism, it only needs to achieve this **across the whole portfolio** of projects that deliver an aggregate output for the network.

PRINCIPLES OF MODELLING AND QA

There are several key considerations in econometrics that the model has to respect to ensure the results are statistically robust. They have each been considered in the design and execution of the econometric model.

1. Overfitting

Overfitting in this context refers to use of too many explanatory variables in an econometric model to create a model that performs too well on the 'training' dataset, at the expense of performance of 'unseen' datasets. This means that the unit cost allowances would be very well adapted to the data used to create the model (ED2 forecast costs) but may as a result have poor performance when new data is introduced (actual outputs created), as a result of failing to generalize trends in the output-input relationship, instead capturing 'noise' in the input dataset.

For this reason, and for the reason of maintaining simplicity in mechanism design, we believe it is inappropriate to use more than 2 explanatory variables for any given volume driver.

2. Input/test data sets

The econometric model can only be as good as the input dataset used to configure the model. There are many data sources for establishing a relationship between outputs (in terms of MWs and kilometres) and inputs; however, to deliver the characteristics needed for ED2, these datasets should be based on cost drivers as they are forecast to be during ED2, and be the costs found in the relevant network patch- so cost per MW relationships derived outside of the UK, for instance, would not be appropriate. Moreover, the dataset must contain at adequate granularity: the costs of delivery; the consequent changes to installed MWs and kilometres; the asset types in question, and the part of the network impacted (in terms of voltage level).

This is a challenging set of criteria, and thus only one candidate data source is readily available- each DNOs cost forecasts and programs of work being submitted in the ED2 business plans.

A similar dataset is also available for the ED1 period and has the benefit of being influenced by our knowledge of actual costs incurred, however this dataset was only deployed as a sensitivity due to these costs being out of date; throughout our business plan, we have sought to achieve efficiency savings over ED1 costs, and these should be anticipated in the ED2 UM design.

3. Econometric measurables

The key measures econometric models return, and their importance, are briefly outlined below; these are the measurables that dictated model selection. They are in 2 groups- the first 4 measures give information about what a particular input-output relationship is, and how strong that relationship is. The second group of measures give information about how well the described relationship performs in returning allowances that are close to actual costs.

<u>Regression metrics</u>

Intercept: The value of cost at an output of 0- this is essentially a standing charge for any project that intends to deliver outputs. Minimising this number, and ensuring it is positive, makes use of the derived relationship more robust

Coefficient: This is the Unit Cost Allowance for a given output, under a given model

Accuracy: This is an adjusted R-squared value. R-squared value is the square of the difference between the modelled value (ie the cost the UCA returns) and the actual value in the training dataset, across the whole dataset, adjusted to consider if additional inputs would improve the model or not; this is a useful tool for comparing model quality as explanatory variables are added.

Statistical significance (p-value of F test): This significance tells us if the model is better than an intercept only prediction; the lower this value is, the more likely it is that the model is providing useful predictions

<u>Performance metrics</u>

Performance: Average of actual cost incurred less the UCA predicted cost for a randomized portfolio of projects

Resilience 1: the standard deviation of the performance metric across 1000 randomized portfolios

Resilience 2: The Coefficient of variation of the performance metric. The coefficient of variation is the ratio of the standard to the mean. It shows the extent of variability in relation to the mean of the population across 1000 randomized portfolios

Median deviation: Median of the performance metric across 1000 randomized portfolios

Skewness: A measure of the asymmetry of the distribution of results- this shows if the model has a bias towards over or under estimation

Kurtosis: This is a measure of the 'tailedness' of the distribution- thus it reflects if the model tends to generate many or few outlier results, with extreme error

4. Model types

Before we can set useful UCAs we need to establish if there is a clear statistically robust relationship between selected measures and costs. The statistical relationships we tested for performance were limited to the following 4:

1. Linear - 'If I change the independent (x) variable by one unit, what is the unit change in the dependent (y) variable?'

2. Log-Linear - 'If I change the independent (x) variable by one unit, what is the percentage change in the dependent (y) variable?'

3. Linear-Log - 'If I change the independent (x) variable by one percent, what is the unit change in the dependent (y) variable?'

4. Log-Log - 'If I change the independent (x) variable by one percent, what is the percentage change in the dependent (y) variable?'

5. Dependent variables tested

The right dependent variable is a trade-off having a strong enough relationship with the cost and being general enough to be readily understood by stakeholders and widely applicable. These variables represent the actual 'volume' being driven.

These could be an output of the network, such as amount of connections facilitated. However, these likely do not have a strong enough connection with costs; for good reasons associated with clustering of demand both locationally or temporally (through herding behaviours increasing peak, for example) and historic network design, few connections can cause expensive works, and vice versa.

A further, dominant consideration is the availability and robustness of data. The development of the ED2 business plan has led to the creation of a very robust dataset that links spend to a set of useful outputs; as a statistical approach like this is fully dependent on data quality, this is a key factor in our selections for testing with the model.

Our tested dependent variables are therefore:

- Length of circuit, with different variables for overhead and underground
- MVA of capacity released, with different further categorisations tested: circuit or non-circuit, and flexibility

These could also be tested as having the different relationships with cost outlined in the preceding 'Model types' of section.

1.1 MODEL STRUCTURE AND EVALUATION

The model structure uses the inbuilt Excel Regression analysis, part of the Data Analysis toolkit. This regression is a standard analytical environment, wherein the user defines explanatory and dependent variables, and the relationship type to be tested, and the tool returns optimal coefficients, intercepts and performance metrics.

To structure the model, cost data from the ED2 planning process was gathered, sorted and cleansed, to create a clear set of linked input and outputs- wherein for each cost (the dependent variable) the explanatory power of inputs such as MWs and kilometres, circuit or non-circuit and voltage level were extracted and set out in the appropriate format for the Data analysis toolkit to be able to process them as an econometric model.

The selection of ED2 data is a key point; this data has been developed taking into account forecast efficiencies to be achieved by ED2, and thus reflects the lower costs we should be achieving in the period. This contrasts with historic costs, which **could** have been included in the regressions; these have the positive aspect of being actual incurred costs, however they do not then reflect our ambition to become more efficient and would drive a higher unit cost allowance if used. ED1 cost data was also prepared and tested for completeness and as a reference point, however, does not form a part of our proposed UCAs to ensure consumers see the value of our targeted efficiencies within the UCAs.

For each of the models tested, the desired explanatory variables were selected (never more than 2 explanatory variables to avoid overfitting and the resultant mechanism being overly complex), and a desired model type (assumed relationship between inputs and outputs- linear-linear, log-linear etc).

Following this setup phase, the Regression Analysis was run in a standard configuration. This then reported the coefficients, intercepts and performance statistics as detailed in the preceding section. An example set of results is presented in the tables below.

Table 3- results for a single regression of cost results with MVA Released

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.379144
R Square	0.14375
Adjusted R Square	0.130159
Standard Error	[redacted]
Observations	65

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	[redacted]	[redacted]	10.5766	0.001842
Residual	63	[redacted]	[redacted]		
Total	64	[redacted]			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	[redacted]	[redacted]	3.135203	0.00260	[redacted]	[redacted]	[redacted]	[redacted]
MVA Release	[redacted]	[redacted]	3.252174	0.00184	[redacted]	[redacted]	[redacted]	[redacted]

Promising models, with a low p-value of the F test, show promising potential UCAs, wherein the coefficient of the explanatory variable (MVA release in this instance) is the recommended UCA. However, the intercept, also presented, represents the fixed value that should be added on to the UCA multiplied by the output figure.

Model evaluation- Monte Carlo analysis

With multiple models now available to test, the Monte Carlo stage is now performed. The Monte Carlo test shows overall performance of a set of assumed relationships against randomized project portfolios. This is helpful as it shows us how the model performs in the face of lots of different requirement combinations, reflecting the reality that what the model will have to work with is 'uncertain'.

A Monte Carlo simulation refers to a simple test of the range of outputs that are obtained based on uncertain inputs. How the input uncertainty is characterised is key to the meaning and value of the results.

For evaluating these regressions, the uncertain input is what actual costs develop- this uncertainty is therefore modelled as a random selection of projects of known costs.

The output that is then under scrutiny is the difference between the cost developed by the UCA method, which is what allowance would then be claimed for that set of projects, and the 'actual' cost obtained by summing the randomly selected projects.

The steps of the analysis are shown below, for the example of finding an MVA released UCA for EHV schemes (but equally apply to other metrics on other defined asset groups, and for flexibility):

1. Select 10 random projects from the population- note that the population should match the regression being tested. If we are testing using MVA released at EHV and above, then the population of projects to use should be those that release MVA at the EHV level

2. Measure the key statistics about this set of projects- the sum of actual costs, and the total MVA released in this example

3. Use the total MVA and the UCA found in the regression to calculate what the allowance for the DNO would be if this UCA would use

4. Compare the UCA calculated allowance to the actual cost, and record the difference

5. Repeat the analysis with a new randomised selection of projects 1000 times to understand characteristic behaviour of this UCA

The results of this analysis are appended for 9 models in each region; these tables present how each of the 9 regression models performed over 1000 random draws, as per the described "Performance metrics" in the preceding section. The best performing models in these tables are reflected in Table 2, as the recommended UCAs for SSEN.

[redacted]

Table 4- models in final UCAs are M2, M6 and M7

[redacted]

Table 5- Models in use in final UCAs are M2, M6 and M7