Annex 29: Uncertainty Mechanisms

This annex sets out our views on managing uncertainty in the period of RIIO-ED2

It considers and covers all the uncertainty mechanisms propose by Ofgem in its framework decision, and where applicable includes comments or additional proposals from ENWL.

December 2021

Contents

1. Our approach to managing uncertainties

1.1 How we'll deal with uncertainties

Our sector is entering a period of fast moving change that means there are increased uncertainties around our plan that we simply do not yet know. We make forecasts and assumptions as accurately as possible, but given the significant change expected in our sector it is not always possible to know what will happen for certain.

RIIO-ED2 represents a period of new challenge for the sector. The speed and degree of change required to facilitate a successful transition to Net Zero increasing significantly which adds to the challenge of delivering on our customers' and stakeholders' priorities identified through our enhanced engagement as part of our RIIO-ED2 business plan development.

To address these new challenges in our business plan, we have embraced the use of fast acting uncertainty mechanisms which are agile to need and provide timely remuneration of costs, aligning funding and activity to the year it is required. In general, we would normally opt to adopt upfront (ex-ante) baseline funding for activities which gives us strong incentives to seek to be as efficient as possible and reduces the administrative burden on stakeholders. However, we recognise that consumer needs in RIIO-ED2 are different and have adapted our approach in this plan to utilise uncertainty mechanisms accordingly.

In our plan we have developed workable solutions where the activity to be delivered is significantly dependent on, or impacted by, factors outside of our control, and there is the potential for the timing, volume of activity, and/or the need to be uncertain. The mechanisms we have proposed are a mixture of those that are proposed to be common to all DNOs, and others that are bespoke to ourselves to reflect the particular operational challenges within the North West.

Our final business plan has been developed on the basis that these solutions are accepted by Ofgem. Any changes to how uncertainty is managed compared to our proposals will mean we will need to put forward business plan changes to Ofgem once we understand the final intentions for how mechanisms will work. We seek to continue to work with Ofgem so that our proposed uncertainty mechanisms can be agreed and included in our draft and final determinations.

Should Ofgem advise different treatment of uncertainty to our proposals then we will need additional ex-ante costs to be allowed in our final determination to ensure our customers and stakeholders can be secure in the knowledge that their needs will be met in a timely manner.

Ultimately the approach we have set out in this document and in our wider plan ensures that the Net Zero transition, as well as the outcomes our customers and stakeholders have told us they need, can be delivered.

1.2 Drivers of uncertainty

Uncertainty comes in the form of either internal or external risk. Internal risk should be managed by us as we are best placed to do so.

An important example of an external uncertainty is how customers pay for connecting to and use of the distribution network, namely the Access Significant Code Review (Access SCR) led by Ofgem. How this policy review progresses and the response of network users to any policy changes is key. Other SCRs are underway, though of unknown materiality of impact based on our current understanding and where Ofgem decisions are yet to be made.

Due to the nature of our funding as a DNO, we require uncertainty mechanisms to enable us to manage the impact of factors beyond our control, these factors could be; changes to central or local government policy, change driven by our regulator or regional stakeholders, or general changes in customer behaviour, needs and expectations.

1.3 How we have developed our proposals

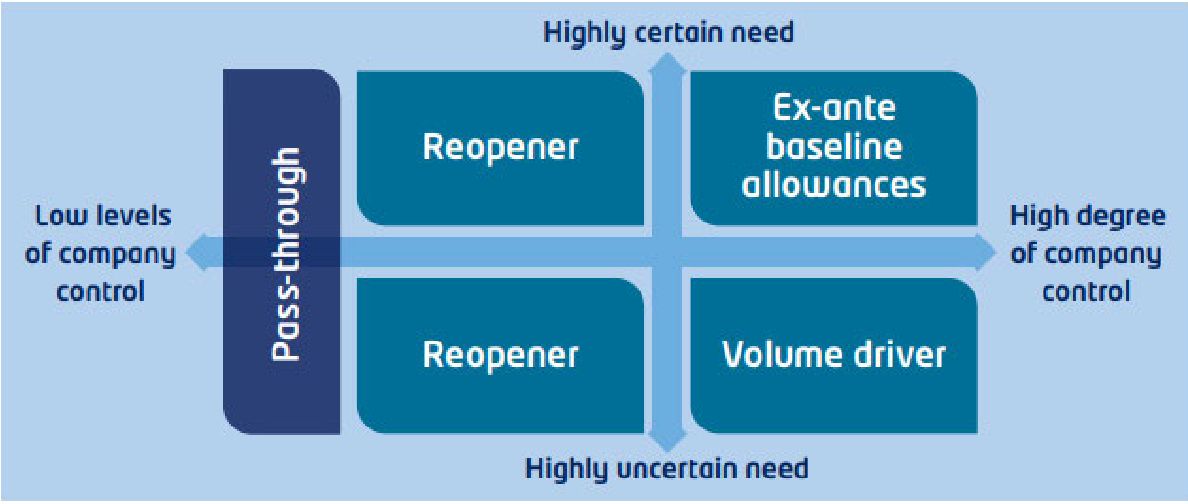
We have continued to work actively with Ofgem on the detailed definition and design of uncertainty mechanisms ahead of RIIO-ED2. Clearly this is becoming a more urgent process. To support Ofgem in its framework development we have included:

- Workable solutions to areas where further detail in the current regulatory framework for ED2 is needed.
- Our views on some of the Ofgem suggested ways of dealing with uncertainty and set out targeted amendments and additional details which aim to enhance the proposed framework.
- Bespoke mechanisms that we require to be included to deal with the circumstances we operate in within the North West.

In determining whether a cost area or activity requires an uncertainty mechanism, and what type of mechanism is applied, we have applied a principle-based approach which we have set out below. This principle-based approach simply considers:

- the ability of the company to control the cost or volume of activity required;
- the ability for the regulator to know what an efficient cost or level of activity should be; and
- the materiality i.e. is the activity or cost sufficiently meaningful that an uncertainty mechanism is required.

How uncertainty mechanisms might be applied in principle



Generally, the types of uncertainty mechanisms that we and Ofgem are considering for RIIO-ED2 take a range of forms including:

- **Pass-through** – these are items outside company control but where it is certain that they are required; such as the fees we pay to Ofgem to fund their regulation activities.
- **Volume drivers** – where the efficient cost per activity or outcome is known but the level/ scale of the activity or outcome is unknown; volume drivers adjust or flex to allow for material changes in the volumes required.

- **Re-openers** – The company usually sets out to Ofgem the activities and outcomes, alongside the efficient costs to deliver them and why the additional cost or volume of activity is, or has been, required.
- **Indexation** – For a limited number of cost allowances it is also necessary to consider if the cost area should be specifically indexed. Indexation is where the scale of costs and volumes is known, but it is also known that the costs will change in a way by reference to a measurable index. The index scales the costs up or down to calculate the efficient costs are in future years when incurred. This is usually undertaken on an annual basis.
- **Use-it-or-lose-it (UIOLI)** – These are allowances that are allocated to be used in defined circumstances, situations or for specified activities. Because the costs are ring-fenced to a clear definition, they can't be transferred or reallocated and companies have two options; to use the allowance if the situation or circumstances requires or, if not required, to return the allowance to customers.
- **Logging-up** – This is a process by which a DNO is fully compensated for actual activity and expenditure on a certain activity over a specified period (preferably annually).

1.4 Our track record of managing uncertainty in RIIO-ED1

We have a strong track record of managing change, without resorting to requests for re-openers or uncertainty funding which is evidenced by our activities in RIIO-ED1. RIIO-ED1 had a specifically challenging set of circumstances due to the duration of the price control, meaning we needed to manage uncertainty over an eight-year period, rather than five years as the duration of price controls has been historically and will be for RIIO-ED2.

In RIIO-ED1, we only triggered and used re-openers when absolutely necessary, with our only application being for specified street works costs. This was where additional requirements were imposed on us by the extension of street works permitting. This demonstrates that we only trigger and apply for what is needed and allowed for under the re-opener definition. We were also the only DNO to be allowed our full application value.

Further to this, we were the only successful DNO to apply for Innovation Rollout Mechanism (IRM) funding via the innovation uncertainty mechanism in RIIO-ED1. This was where we identified and requested additional funding in RIIO-ED1 that is now creating significant consumer benefits due to our rollout of 'Smart Street'. Without the successful application, customers would have had to wait for RIIO-ED2 for the benefits to be realised.

Examples of our use of innovation to avoid a request for increased allowances includes our unique approach to the risk related to link-boxes. In RIIO-ED1, we have championed the use of blast bags as a mitigating measure to address the risk in an efficient manner. We have therefore delivered the required safety outcome whilst maximising efficiencies, which in turn are shared with our customers through the Totex Incentive Mechanism (TIM).

Further, we were the first DNO to introduce the use of prepayment meter top-up vouchers for our customers at the start of the COVID-19 pandemic when it became clear that some customers were struggling to contact their suppliers and were at risk of disconnection through lack of access to top-up their pre-payment electricity meters. We quickly adapted our working methods and continued our activities with minimal impact on our work programmes, whilst also reducing the impact on consumers. We have further managed changes that have increased costs, or changed our ways of working in RIIO-ED1 such as:

- In relation to the increased prevalence of land agents advising land owners on network related claims for wayleave and diversions

- Changes to flood defence requirements following incidents and in-period reviews
- Adjusted our operations to best facilitate the extension(s) of the smart meter rollout programme
- Commenced our transition to DSO activities
- Reflected the change in requirements for the removal of equipment that are identified as contaminated with PCBs
- Adapted to changes brought in by the adoption of the Clean Energy Package
- The introduction of Green Recovery aim in RIIO-ED1

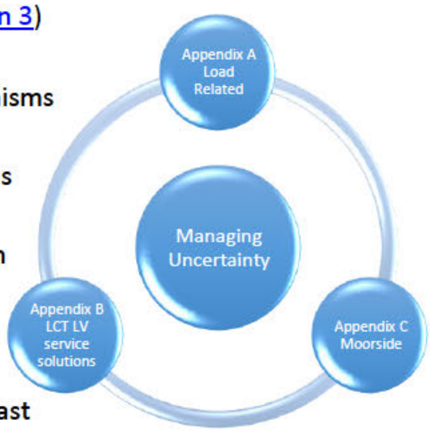
However, our ability to manage uncertainty to the same degree as has been achieved in ED1 is not possible without uncertainty mechanisms given the speed of change to Net Zero transition and our customers stated priorities, coupled with changes to the application of the RIIO framework.

2. Structure of this annex

For RIIO-ED2, a range of uncertainty mechanisms have already been proposed by Ofgem following engagement with stakeholders and covering specific targeted areas. Many of these are revised from RIIO-ED1 whilst some are new for RIIO-ED2, covering uncertainties that Ofgem acknowledges are present for the period of change we are moving to.

This annex has been split into;

- Our view on overarching features for uncertainty mechanisms (section 3)
- Our proposals for new uncertainty mechanisms (section 4)
- Our proposals to help shape new and existing uncertainty mechanisms which Ofgem has proposed (section 5)
- Our comments on all other Ofgem proposed uncertainty mechanisms including miscellaneous pass-through items (section 6)
- Appendix A and Appendix B which provide more detailed proposals on how load related expenditure and LCT LV service solutions should be treated.
- Appendix C sets out detailed revisions to our bespoke Moorside uncertainty mechanism covering Nuclear development on the west coast of Cumbria



3. Overarching features for uncertainty mechanisms

3.1 Ofgem position

In its RIIO-ED2 sector specific methodology decision[1] (SSMD), Ofgem set out its position on common parameters for reopener design, this is summarised in table 3.1 below.

[1] RIIO-ED2 Sector Methodology Decision: Annex 2 Keeping bills low for consumers, Ofgem, December 2020

Table 3.1: Common parameters for RIIO-ED2 as set out by Ofgem in the RIIO-ED2 SSMD

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

In the RIIO-ED2 SSMD, Ofgem was clear that these common design parameters "*would not necessarily apply to all re-openers*"[2] and that the parameters follow those designed and implemented for the RIIO-2 controls for gas distribution, transmission and electricity transmission (GD/T2).

The parameters above are not exhaustive; for example, Ofgem stated that the frequency and timing of application windows will be on set on a re-opener by re-opener basis.

Additionally, Ofgem, in the RIIO-ED2 SSMD also set out the purpose and benefit for setting common design parameters, which we have included in table 3.2.

Table 3.2: Stated purpose and benefits of common parameters for RIIO-ED2 as set out by Ofgem in the SSMD

Common design parameters for re-openers	
Purpose	To provide clarity on the parameters and process relating to re-openers. Re-openers provide the opportunity for network companies to request amendments in allowances, outputs, or delivery dates during the price control, when there is more certainty.
Benefits	Protects both consumers and network companies from uncertainty around requirements, unknown and emerging risks/threats, new regulatory requirements, and technology changes.

3.2 Charge setting period

We welcome the intent of Ofgem to review the price/charge setting notice period as part of the wider DUoS reforms and Significant Codes Review (SCR). Currently, DNOs can only set prices for network use

[2] Ibid.

15 months ahead of time and this price setting process is bound by strict rules within industry codes that networks must follow. This ultimately impacts on how quickly adjusted revenues can be reflected into cashflow, and the gap between cost incurred by the company and recovery is significant in duration. Ultimately this can discourage companies from proposing reliance upon uncertainty mechanisms in a fast-changing environment.

We are proposing that, as part of ensuring re-openers meet consumers' needs, a change to the DUoS charges notice period occurs, with a shortening from a 15-month to 3-months in line with the period of notice for gas distribution charges. This will allow a more agile response to meet consumers' needs and ensure that costs and recovery timing are more closely linked. Given it has been signalled that the DUoS reform review will be formally split out from the Access SCR, we propose Ofgem makes this change to align the notice period for tariff changes to gas distribution to 3 months and does this ahead of RIIO-ED2.

3.3 Our proposal for overarching features

We have considered the common parameters set out by Ofgem in the SSMD and whether we believe they are appropriate and workable in the context of the challenges of RIIO-ED2. We have concerns that the common parameters grounded in the application for GD/T2 have not been considered in the context of RIIO-ED2, as well as considering the information and discussions that have been held in working groups since the publication of the RIIO-ED2 SSMD in December 2020.

The ED sector is unique in respect of the impact and pace of change required because of Net Zero ambition. In response, the RIIO-ED2 framework should be considered on a standalone basis, distinct from GD/T2, to ensure that the framework is fit to enable a smarter, more flexible energy system which is responsive to the drivers of decarbonisation, digitisation and decentralisation. Our stakeholders are asking us to take a leading role in delivering the Government's policy and the RIIO-ED2 framework and its application must therefore facilitate this. It is imperative that uncertainty mechanisms, including re-openers, and any common parameters that are associated with them, support fast acting and agile uncertainty mechanisms which are administered and managed in a timely and consistent manner.

Specifically, it must provide for timely remuneration of cost, in the year of the expenditure, to ensure that companies do not incur cashflow and financeability issues because of slow acting uncertainty mechanisms. Given the volume of work in RIIO-ED2, the transition to Net Zero and stakeholder-led requirements, coupled with challenging financing assumptions for RIIO-ED2, failure to deliver fast acting UMs will potentially mean that activity and investment is delayed, or alternative prioritisation of investment is needed at the expense of scope reduction in-period.

We have chosen to embrace fast-acting uncertainty mechanisms as an integral aspect of our final business plan, as guided by Ofgem. Without such mechanisms being agile, flexible and providing for timely payment, we will need to relook at our plan and seek agreement from Ofgem for appropriate changes. Should suitably fast acting and agile uncertainty mechanisms not be agreed and included in our draft and final settlement, one aspect of remediation required would be for the additional costs of UMs to be included in baseline allowances (ex-ante) in the final regulatory settlement. This would need to be agreed as part of our price control Final Determination as envisaged in our draft business plan submission. This, our final business plan, is therefore contingent upon the full adoption and implementation of the uncertainty mechanisms we have proposed.

We have set out below proposals for overarching features that support fast acting and agile uncertainty mechanisms in table 3.3, whilst also delivering the Ofgem stated purpose and benefits as set out in the RIIO-ED2 SSMD and included in this document in table 3.2 above.

For clarity, we are proposing that the below applies to all uncertainty mechanisms and re-openers as default, unless stated in our sections covering uncertainty mechanisms/ re-opener design in more detail (below or in reference appendices).

Table 3.3: ENWL proposed overarching features for RIIO-ED2 uncertainty mechanisms including re-openers

Re-opener features	Our proposal
3.3.1 Investment/spend included in annual price-setting process	That companies can include forecasted use of re-openers and investment needs in the annual price-setting process. Forecast investment and UM/re-opener needs to be included as part of regulatory reporting/annual iteration process (AIP)[3] where forecast spend will be used in setting of allowed revenue ahead of full re-opener process. Additionally, an updated PCFM with an annual Ofgem published RAV based on the same data is required on the same timings and timescales.
3.3.2 Application window	That the window for re-openers is sufficiently soon, typically in year 3 (of 5), and flexible to need so that allowances can be forecast forward by the company as well as confirmed in a timely way by Ofgem. This will ensure that the process does not become a blocker to the delivery of needed investment.
3.3.3 Trigger	That companies can trigger all re-openers/UMs as required, and that there are no UMs/re-openers that have a unilateral Ofgem trigger only.
3.3.4 Materiality threshold	That materiality threshold for re-openers is set lower in ED2 than in ED1 (lower than 1% of annual base revenues). We propose that 0.5% as per GD/T2 is appropriate. Zero materiality thresholds should apply in cases where the activity or driver is of a legislative nature, compliance or outside of management control (e.g. cyber, regulatory driven changes).
3.3.5 Aggregation	Aggregation across UMs/re-openers can occur.
3.3.6 Closeout	That no UM/re-opener is dealt solely through a RIIO-ED2 closeout mechanism and that rules for any closeout should be clear before the start of the price control.
3.3.7 Take no account of the general Totex performance of the licensee	In RIIO-ED1 some new allowances have only been provided to companies who had already spent all the Totex allowances provided at the start of RIIO-ED1. In these cases, efficient companies delivering their outputs are penalised for generating efficiencies whilst overspending companies are provided further funding. This should not be the approach in ED2.

For the avoidance of doubt where we refer to DNO in this document this refers to DNO licensee level not group. We would be happy to discuss our proposals with Ofgem in more detail.

[3] Or equivalent in RIIO-ED2

3.3.1 Investment/spend included in annual price-setting process

One of the key requirements for fast acting and agile uncertainty mechanisms is to ensure that companies can access additional allowances as soon as they are required in order to ensure that investment is not unnecessarily delayed. This is equally needed for any return to customers if investment is lower than forecast and it is important that this can also be done in a timely manner.

Ofgem have proposed that the approach taken for GD2/T2 of including licensee forecast use of UMs and other variable values to adjust allowed revenues as a live calculation should also apply to ED2. We agree with this proposal as it will achieve the aim of supporting a fast acting and agile regulatory framework, reducing the risk of the ED2 framework being a blocker to Net Zero aims. We therefore agree that companies should be able to include their forecasted use of re-openers and investment needs in the annual price-setting process. Including this as part of regulatory reporting and the annual iteration process (AIP)[4] will allow companies to use this pipeline of investment requirements in setting of allowed revenue ahead of full re-opener processes.

It is also critical that this forecast should be a company forecast, consistent with Ofgem regulatory submissions and used for business planning purposes and should not be a standalone forecast purely for the use of setting charges. Companies should have a reasonable degree of expectation that the forecast will align with their re-opener applications in due course.

This will support companies in timely delivery of investment where the need is required, ensuring that customer and stakeholder priorities are met through timely cashflow and closer alignment of spend and cost recovery. Failure to deliver this will see cashflow issues for companies, as well as potential financeability issues meaning that spend under uncertainty mechanisms/re-openers will be put at risk of being delivered. It could alternatively mean prioritisation is needed reducing the overall scope of delivery to what is a viable given cashflow and financeability constraints.

Given the speed and magnitude of activity needed in RIIO-ED2, it is important that the pronounced time-lag between Ofgem decisions for adjustments to allowances and that change being reflected in actual revenue collected is not continued in RIIO-ED2. Our proposal here is central to addressing this issue and will enable us to more rapidly act to meet consumer and stakeholder needs, as well as any legislative changes/requirements.

It is also crucial that an updated PCFM with an Ofgem published RAV for each licensee based on the same data as AIP (or equivalent) is produced. A published RAV is essential to ensure that companies can raise finance as required against the latest information available. Therefore, an annual Ofgem-published RAV on the same timescales and timings as the AIP (or equivalent in ED2) is critical to remaining financeable in the period.

3.3.2 Application window

It is important that the window for re-opener applications and uncertainty mechanisms is sufficiently soon in the price control period. We would support that this is typically in year 3 but are flexible to need so that this can be brought forward where allowances can be forecast by the company, as set out in section 3.3.1. This will ensure that the process does not become a blocker to delivery of needed investment, giving companies clarity and certainty from Ofgem as to the confirmation of allowances being provided.

As proposed by Ofgem, we support bringing forward the application window from May to January. It is clear the main benefit is a longer assessment time for Ofgem, however, this is not consistent with

[4] Or equivalent in RIIO-ED2

the need for agile and timely decision making as the speed of decarbonisation and the pathway to Net Zero becomes clearer. Consumers and industry need a quicker and more appropriate approach to re-opener decisions, particularly given the large number of decisions Ofgem is likely to need to make in RIIO-ED2. It is unlikely to be sustainable without an overhaul to the decision-making processes and the risk will be carried by companies until an Ofgem decision is made. Uncertainty of Ofgem decisions could start to impact consumers during the price control if companies respond to awaiting Ofgem decisions by deferring meeting consumers' needs. It is however much more important that our proposals in sections 3.3.1 and 3.2 are included in the regulatory framework as this would help to minimise any impact of timescales regarding Ofgem decisions on uncertainty mechanisms and re-openers through fast acting and agile remuneration for customers and companies.

3.3.3 Trigger

We are proposing as default that companies can trigger all uncertainty mechanisms and re-openers as required.

We don't support that uncertainty mechanism and re-openers should be authority-only as default and equally, where Ofgem proposes that a unilateral Ofgem-only trigger should apply, the justification of consumer benefit needs to be clearly demonstrated. Further, and for clarity, we see no example in the uncertainty mechanisms set out in the SSMD and in our proposal for other mechanisms contained in this document as well as associated documents where an Ofgem only trigger should apply and can be justified.

We have concerns that a unilateral Ofgem trigger will increase uncertainty for companies, reduce timeliness of applications thereby raising risk and costs for consumers in the long run given the likely impact on cashflow and financeability.

Additionally, the process for triggering uncertainty mechanisms and re-openers should be the same for both Ofgem and companies in terms of certainty and clarity as to what might be triggered and when. This isn't the case as it stands in the proposals where only Ofgem can trigger at any point. If Ofgem were to wish to trigger a mechanism unilaterally it must give adequate notice to allow companies and stakeholders to prepare the necessary inputs and evidence. Certainty and clarity underpins good regulatory practice. An open-ended asymmetrical process does not provide this to companies and stakeholders alike.

3.3.4 Materiality threshold

We support that the materiality threshold for uncertainty mechanisms and re-openers for RIIO-ED2 is set lower than that which applied in RIIO-ED1. We are therefore proposing that that a materiality threshold of 0.5% of annual average ex-ante base revenue applies which would align RIIO-ED2 with the materiality threshold of RIIO-GD/T2. Additionally, we are proposing that a zero-materiality threshold should apply in cases where the activity or driver is of legislative or compliance nature, or outside of management control (e.g. cyber).

By the Ofgem definition a materiality threshold "*provides a balance to ensure network companies and consumers are protected from significant variations in expenditure over the price control*"[5]. It would therefore seem practical that the materiality threshold should be reduced for RIIO-ED2 to reflect the reduced length of the price control from 8 years in RIIO-ED1 to 5 years for RIIO-ED2.

[5] RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, paragraph 11.56, Ofgem

This is especially true where the degree of risk and level of uncertainty has increased for the forthcoming period as demonstrated by the breadth and depth of UMs to apply in RIIO-ED2.

3.3.5 Aggregation

We are proposing that aggregation across UM/re-openers can occur. The flexibility to aggregate uncertainty mechanisms and re-openers where there are items that don't meet materiality on their own ensures that outcomes and investment can still happen without the risk of cashflow and financeability issues occurring.

Additionally, given that materiality thresholds are designed to provide "*a balance to ensure network companies and consumers are protected from significant variations in expenditure over the price control*"[6] it is also not clear why a higher or even a different materiality threshold should apply to aggregated items. Therefore, in scenarios of aggregation we are proposing that a 0.5% materiality threshold applies as set out in section 3.3.4 above.

3.3.6 Closeout

Given the need for clarity and certainty, as well as fast-acting and agile uncertainty mechanisms we are proposing that no uncertainty mechanism or re-opener is dealt with solely through a RIIO-ED2 closeout mechanism. Additionally, and building on the lessons that can be learned from RIIO-ED1, the rules for closeout should be clear and sufficiently detailed before the start of the price control and should be provided in such a way (i.e. via licence) that these, or their absence, can be raised to the CMA if necessary, as closeout is a vital part of the price control.

3.3.7 Take no account of the general Totex performance of the licensee

Under the Ofgem Green Recovery mechanism in RIIO-ED1, new allowances have only been provided to companies who had already spent all the Totex allowances provided at the start of RIIO-ED1. In these cases, efficient companies delivering their outputs, are penalised for generating efficiencies, whilst overspending and potentially less efficient companies are provided with further funding.

This approach to only provide new allowances to overspending companies reduces efficiency incentives and perversely could lead to companies being more relaxed about costs, spending all their allowances in anticipation that overspending companies will be the only ones to receive new additional allowances.

In RIIO-ED2 there should be no decision-making element on any regulatory cost adjustment via a reopener based on a company's overall Totex spend compared to allowances.

[6] RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, paragraph 11.56, Ofgem

4. Our proposed new uncertainty mechanisms

We have proposed new uncertainty mechanisms should apply for the ED2 period. These are set out in table 4.1 below.

Table 4.1: ENWL proposed uncertainty mechanisms for ED2

Area	Type of Uncertainty Mechanism[7]	Existing or new for ED2 (as proposed by ENWL)	Section
Load related expenditure	Re-opener	Existing – revised from ED1	Section 4.1 and Appendix A
LCT LV service solutions	Volume Driver	New	Section 4.2 and Appendix B
Wayleaves and Diversions	Multiple	New	Section 4.3
Ash Dieback	Volume Driver	New	Section 4.4
PCBs	Volume Driver and logging-up	New	Section 4.5
Net Zero and re-opener Development Fund (NZARD)	UIOLI	New – based on RIIO-GD/T2	Section 4.6.2
Distribution Net Zero Fund	UIOLI	New	Section 4.6.3
Moorside – Nuclear development on the west coast of Cumbria	Re-opener	Existing – revised from ED1	Section 4.7 and Appendix C

4.1 Load Related Expenditure re-opener

Load Related Expenditure (LRE) is a critical component of a DNO's business plan; it facilitates customers' requirements, enables economic and regional growth and supports the transition to Net Zero.

LRE has a range of drivers and a number of associated uncertainties, all of which must be carefully considered when designing an Uncertainty Mechanism (UM).

The approach for LRE in previous price controls has served customers well for many years, and our proposal is to take the existing elements of the RIIO-ED1 mechanisms, and with a limited number of revisions ensure that they continue to be fit for purpose for the challenges we will face in RIIO-ED2.

Our proposal takes a holistic look at all the components of LRE and delivers Ofgem's aim of simplification in the price control where possible. It comprises three key mechanisms, each dealing with uncertainty in a slightly different manner. These three combined are complementary and provide a whole solution to the range of load related expenditure that may be incurred. The three components are shown in the 4.2 figure below.

[7] Some of these activities will have ex-ante allowances associated with them, in addition to the UM proposed treatment.

Figure 4.2: Three complimentary uncertainty mechanisms proposed for ED2

High Value Projects

- To deal with large projects, £18m + allowing an appropriate level of project level scrutiny
- Protects customers from risk of non-delivery
- Provides the DNO with the ability to revise allowances, or bring forward new projects

Load Related Re-opener

- Flexible enough to deal with changes driven by Access SCR outcomes
- Can cover all reinforcement drivers, all voltages and all solutions including flexibility services and energy efficiency
- Encourages innovation
- Protects customers from forecasting risk
- Enables DNO to flex allowances to meet changing needs

LCT LV Service Solutions Volume Driver

- Removes a key barrier to LCT adoption
- Deals with volume uncertainty
- Keeps bills as low as possible, only increasing as requirements increase
- Enables automatic adjustment to revenues

Detail on High Value Projects can be found in section 5.9, whilst further details on Load Related Re-opener and LCT LV service solutions volume driver can be found in Appendix A and Appendix B respectively.

4.2 Addressing the services barrier to Net Zero – Providing LCT LV Service Solutions

An increasing need in RIIO-ED2, driven by Net Zero aims and the decarbonisation of heat and transport, is the need to manage constraints at domestic properties. Constraints can be caused by a range of issues at the service point:

- Being connected to the distribution network via a looped service
- Having a fuse rating which is insufficient for the customers demand needs
- Having a cut-out which is unable to accommodate a new fuse
- Having a service cable which is an insufficient size to meet the customers demand needs

Each of these constraints may prevent a customer connecting and using their LCT in the manner they wish and therefore needs to be addressed.

For many years these characteristics have existed, causing no issues for customers until they wish to significantly change their demand and use requirements, at which point intervention by the DNO is required.

We are already witnessing the volumes of customer enquiries and subsequent work at the service point needed as a result of LCT uptake growing rapidly, with a pronounced increase during 2021 alone. We expect this growth trend to continue in line with our DFES forecast of the uptake of LCTs. The precise growth and volumes, however are uncertain.

Below we take each form of constraint in turn.

4.2.1 Looped Services

Historically, looped services were installed as an economic and efficient way of connecting new properties mainly in the 1960s and 70s and were commonly used for new terraced houses and new housing estates. This was a safe and efficient way of constructing the network at that time and has provided satisfactory performance for many decades based on average domestic demand and network usage.

As we enter a world where customer demand and network usage are starting to change as a result of the uptake of electric vehicles and heat pumps, looped service ratings can be exceeded when such LCTs are connected. It is important to remove this risk and ensure that the electrical network is not a barrier to the uptake of Low Carbon Technologies (LCTs) necessary to meet the national Net Zero target.

As this is an established activity in RIIO-ED1 our understanding of unit cost is improving, however we have less certainty over the volumes as variability includes:

- volume of EVs which will connect in our region,
- location of these EVs, i.e. whether chargers will be connected at a property with a looped service; and
- customer acceptability for the intervention.

4.2.2 Enhancing the Fuse Rating

In the case of an enquiry about installation of an LCT, the installer provides the current fuse rating and total maximum demand, including the LCT. If the maximum demand exceeds the fuse rating then the DNO will attend site and complete a fuse upgrade, i.e. installing a larger size fuse.

4.2.3 Upgrading the cut-out

There are certain types of cut-outs that are unable to accept a fuse upgrade. In these instances, the old cut-out needs to be removed and a new cut-out capable of accepting the larger fuse size installed. Work to do this can be done either “live” or “dead” depending on circumstances. We have some instances where the operative is able to complete the change whilst keeping the incoming service cable “live”. Depending on the type of cut-out, the cable may need to be made “dead” which would involve excavation to complete a safety cut on the existing service cable to temporarily remove power to make the property dead, allowing us to safely remove the old cut-out and install the new upgraded one. The existing service cable would then be reconnected to make “live” once again.

4.2.4 Uprating the Service Cable

Every service cable has a maximum current rating based on the size of the conductor. If a property has an inadequately rated service cable (typically 16mm), we need to install a new larger service cable. In order to do this, an excavation will be required, and new service cable installed. We refer to these as service cable uprates.

4.2.5 Funding Treatment

Ofgem is engaging with DNOs as there is currently disparity amongst licensees in terms of the RIIO-ED1 regulatory funding treatment for work in this area.

In RIIO-ED1 our charging treatment differs depending on the driver for intervention:

- All unlooping constraint intervention, regardless of the driver, is treated as Reinforcement funded via DUoS within the price control;
- All service related work (fuse upgrades, cut-outs and service replacements) which is required as a result of a customer installing an LCT is treated as reinforcement funded via DUoS within the price control;
- All service related work (fuse upgrades, cut-outs and service replacements) which is required as a result of all other customer requirements (non LCT related) is currently chargeable to the customer.

We anticipate that this differing approach based on the customer driver may change for RIIO-ED2 with clarification of charging rules from Ofgem. The current anticipated outcome is that [redacted]

Any change to the current treatment will increase the overall costs within the price control as the cost of work which would previously [redacted]

These two aspects of uncertainty, growth of work driven by LCTs and change from [redacted] non LCT other service related work, will change the allowances needed to deliver these critical services for our customers.

Due to the range of uncertainties associated with the volumes required for these activities and the potential magnitude of expenditure, we propose that this activity is separated from Load Related Expenditure and Ofgem introduces an uncertainty mechanism specifically for managing constraints at the service point in domestic premises which is able to adjust revenues upwards or downwards accordingly. Further detail on this proposal is shared in Appendix B.

4.3 Wayleaves and Diversions

4.3.1 Introduction

To undertake our day to day activities and manage the assets on our network we require formal consent to both install and access our apparatus situated on or over private lands. This includes overhead lines and underground cables at all DNO voltage levels[8]. These rights are typically secured through wayleave agreements or easements.

Wayleave agreements are 'terminable' licences which are legally determined when either party changes, or the statutory process is invoked to terminate the agreement and remove the apparatus. Easements secure consent in perpetuity. Wayleaves are subject to annual rental and/or compensation payments. In comparison, easements are secured by a one-off consideration payment.

Where assets are located close to properties (HV, EHV or 132kV and within set distance parameters for each voltage), claims for Injurious Affection (IA) are submitted to the DNO by land agents or directly from property owners. IA claims apply a percentage diminution based on the distance and impact of the apparatus against the property value, to arrive at a settlement value which is paid in lieu of an easement. This generally applies to our EHV and 132kV network and is localised and case specific. HV claims have a specific agreed strategy for the purposes of settlement and consent.

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[8] LV, HV, EHV and 132kV

IA claims against our HV wood pole network and set value claims against our LV network are managed through individual strategies for each voltage level. In comparison to the EHV/132kV IA claims, HV claims have to date been [redacted]

Settlement of these claims comes at a significant cost to DNOs and our customers. There are several factors that impact on the cost to the DNO for IA claims which include, but are not limited to;

- the property value,
- the voltage level of the asset in question,
- type of agreement sought or in place (easement or wayleave),
- person claiming (i.e. single property or domestic/industrial development claim)
- agent and legal fees for all parties.

Additionally, because of:

- The impact of COVID-19,
- Awareness of claims through propagation of third party agents,
- Increased access to our asset data, and
- Development losses through planning reforms including brown and greenfield site development;

the volumes of claims[9] likely to be received are uncertain for the period of RIIO-ED2. It is most likely that the uncertainty is only on the upside; i.e. that claim numbers in the period will be significantly higher than RIIO-ED1 on a like for like basis, with overall costs materially higher.

For our draft business plan submission (DBP), we included all costs and volumes for wayleaves and easement claims as well as the diversions costs for wayleaves terminations and diversions for highways in our baseline (ex-ante) proposal.

4.3.2 Our proposal

Having reviewed and considered the best treatment for the cost and activity as part of finalising our business plan for submission in December 2021, we are now proposing the use of uncertainty mechanisms as well as some ex-ante (baseline allowances) in this cost area. We consider this approach is the best treatment of the costs and volumes due to the uncertainty of the scale of the increase in these costs from RIIO-ED1 levels.

We set out our proposals in more detail for each of the areas below including the reason why these are best treated via our proposal, what the uncertainty mechanism is (if applicable) and how this would work for the RIIO-ED2 period. For transparency and because of the nuances between the various areas and types of claims we have split our proposals into the following areas:

[9] Particularly the case for wood pole claims, development claims and the anticipated underground cables claims, as well as diversions from wayleave terminations.

- Wayleaves and Easement compensation claims (section 4.3.2.1)
  - Wayleaves and Easement compensation claims – LV
  - Wayleaves and Easement compensation claims – HV
  - Wayleaves and Easement compensation claims – EHV and 132kV
- Wayleaves and Easement compensation – development claims (section 4.3.2.2)
- Diversions for wayleaves terminations (section 4.3.2.3)
- Diversions for highways (funded as detailed in NRSWA) (section 4.3.2.4)

4.3.2.1 Wayleaves and Easement compensation claims

As set out in section 4.3.1, the volume of wayleaves and easement compensation events in RIIO-ED2 is uncertain.

Given this volume uncertainty for LV and HV wayleave and easement compensation claims, we are proposing that these are best treated through an uncertainty mechanism in the form of a volume driver.

Whilst the costs between wayleave agreements and easements vary, these can be reasonably estimated by voltage level and based on an optimal solution at each level. We routinely undertake these activities in RIIO-ED1 so know what the efficient costs are. Therefore, we are proposing that separate unit costs [redacted]

We will always seek to agree the most efficient value for money solution for our consumers and as such in developing our RIIO-ED2 plan we have considered and based the costs and volumes on the most optimal and efficient strategy for our consumers.

To evidence this, we are only proposing a single rate applies to LV to cover [redacted]

For HV for RIIO-ED2, we have reviewed our strategy in RIIO-ED1 considering wider sector best practice and as such our strategy will be [redacted]

For clarity, the numbers contained in the section below 4.3.2.1.2 are [redacted]

4.3.2.1.1 Wayleaves and Easement compensation claims – LV

We are proposing that LV wayleaves and easement compensation claims are dealt with through a volume driver [redacted]

The table below sets out our central assumptions for RIIO-ED2, including the overall cost and the unit rate which we are proposing should apply for LV in an annual volume driver with a zero-materiality threshold. To be clear, the table is our forecast volumes and we are proposing that all are dealt with through a volume driver uncertainty mechanism with zero ex-ante baseline allowances.

Table 4.3.1: LV forecast costs and volumes and unit cost to be included in volume driver uncertainty mechanism proposal for final business plan

Activity and Voltage		Treatment	Forecast costs and volumes in RIIO-ED2					Cost and unit cost in uncertainty mechanism (M13)
			2023 /24	2024 /25	2025 /25	2026 /27	2027 /28	
Wayleaves and Easement compensation claims	LV	Annual volume driver (zero materiality)	[redacted]					

4.3.2.1.2 Wayleaves and Easement compensation claims – HV

As set out in section 4.3.2.1, for HV claims in RIIO-ED2 we are proposing that [redacted] Further to this we would:

[redacted]

Figure 4.3.2: House price trend for the North West (average house price)[10]

Given the evidence above and our strategy [redacted] we are proposing that an uncertainty mechanism for HV wayleave and easement compensation claims applies in RIIO-ED2. We are proposing that all costs and volumes are dealt with through the mechanism. As per LV, the uncertainty in this area concerns the volumes of claims in the period and [redacted]

The table below sets out our central assumptions for RIIO-ED2 including the overall cost and the unit rate which we are proposing should apply for HV in an annual volume driver with a zero-materiality threshold. To be clear the table is our forecast volumes and we are proposing that all are dealt with through a volume driver uncertainty mechanism with zero ex-ante baseline allowances.

Additionally, for HV only, [redacted]

Table 4.3.3: HV forecast costs and volumes and unit cost to be included in volume driver uncertainty mechanism proposal for final business plan

Activity and Voltage		Treatment	Forecast costs and volumes in RIIO-ED2					Cost and unit cost in uncertainty mechanism
			2023 /24	2024 /25	2025 /25	2026 /27	2027 /28	
Wayleaves and Easement compensation claims	HV	Annual volume driver (zero materiality)	[redacted]					

[10] HM Land Registry, Registers of Scotland, Land and Property Services Northern Ireland, Office for National Statistics.

4.3.2.1.3 Wayleaves and Easement compensation claims – EHV and 132kV

For EHV and 132kV claims, as there is more certainty around volumes of claims expected [redacted] we are proposing that costs are included in baseline (ex-ante) allowances and not dealt with through an uncertainty mechanism.

We have challenged ourselves on our assumptions and, as can be seen from the numbers included in our final business plan, the [redacted] This is evidenced in the table 4.3.4 below where volumes and cost are consistent and known compared to recent history.

It should be noted that because of the cost and complexity differences for development claims we have excluded these and set out our proposed treatment in section 4.3.2.2.

Table 4.3.4: EHV and 132kV costs and volumes included in ex-ante proposal for final business plan

[redacted]	RIIO-ED1				RIIO-ED2					Total (ED2 only)
Voltage	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27	2027/ 28	
EHV	[redacted]									
Volumes										
132kV										
Volumes										

4.3.2.2 Wayleaves and Easement compensation – development claims

Developers have a statutory right to be compensated for losses associated with our assets residing on their development land. With the current shortage of housing stock and Government aspiration for more housing to be built, we are seeing increased development on brown and greenfield sites. Additionally, there is now a greater awareness amongst developers and land agents with regards to eligibility of development claims and we are as a consequence, seeing the numbers increasing both within our operating region, as well as nationally.

This is reflected in the numbers of claims we have dealt with; between 2015 and 2017, we received [redacted] claims of which [redacted]. From 2017 to date, we have received a further [redacted] new claims and the [redacted]

Additionally, development claims are large and complex by their nature, where potentially a single site can have diversions activity and the associated costs, as well as claims associated with compensation for assets remaining on the site. The estimation of cost is challenging as every site is unique and no claim is the same. We therefore see the settlement values [redacted] Further, and ensuring that we provide value for money for our customers, we often find [redacted] which we will continue to aim for in RIIO-ED2.

[redacted]

In addition to domestic development claims, industrial developments and associated claims are also increasing. We currently have [redacted] and recently have received [redacted]

We are anticipating an increase in the number of claims (both domestic and industrial) that we receive as we enter RIIO-ED2 and beyond. As evidenced above, the uncertainty for both volume and cost per claim is great and they vary significantly on a case by case basis. It is therefore clear that development claims are not akin to an easement or wayleave settlement on a per property basis at any voltage level where the volumes may be uncertain, but the cost can be estimated on a per claim basis with a reasonable degree of certainty dependent on the strategy it is based on.

Therefore, we are proposing that all development claims (both domestic and industrial) are dealt with through an [redacted] in RIIO-ED2, with clear rules set in advance. It is important that Ofgem validates to the extent they wish that costs incurred during the period are efficient before the [redacted] and this should be done on an annual basis through the RRP process. Because of the small numbers of claims in this area [redacted] we think an [redacted] is valid and would not take significant regulatory time to undertake the review and respond by exception.

The table 4.3.5 below summarises our high-level estimate of development claims for RIIO-ED2 although as stated above these are [redacted] as well as volumes.

Table 4.3.5: Wayleaves and Easement compensation claims - Development claim costs and volumes included in an annual logging-up uncertainty mechanism proposal for final business plan

Activity and Voltage		Treatment	Forecast costs and volumes in RIIO-ED2					Cost in ex-ante (CV5) / UM (M13)
			2023 /24	2024 /25	2025 /25	2026 /27	2027 /28	
Wayleaves and Easement compensation claims (development claims only)	LV	[redacted]						
	HV							
	EHV							
	132k							

4.3.2.3 Diversions for wayleaves terminations

We have seen a sustained and continued increase in diversion costs arising from developer led wayleave terminations affecting our LV, HV and EHV networks. The underlying reason for this is likely the response to Local Planning Authorities (LPAs) designating greenfield sites on the fringe of urban centres as housing sites to meet housebuilding targets set by central Government.

Central and local government literature indicates that they will continue the drive to allocate housing sites for the remainder of RIIO-ED1 and throughout RIIO-ED2, and that the continued expansion of urban areas will drive the need to divert our network to accommodate new developments.

However, the volume of the increase is unknown and challenging to forecast. We are therefore proposing that diversions for wayleaves terminations for LV, HV and EHV are dealt with through a mixture of base (ex-ante) allowances and an annual volume driver for the activity over our base assumptions. To ensure robust estimation and given it is certain that activity will be greater than that experienced in RIIO-ED1 and noting the activity drivers set out above, we have based our ex-ante allowances on a broad roll-forward of RIIO-ED1 volumes and costs.

To ensure that we are efficiently remunerated for activity above this base (ex-ante), level we are proposing that a volume driver applies with rates differing depending on the voltage level of the affected asset for LV, HV and EHV. It is clear, as with wayleaves and easement claims, that the costs vary greatly between voltage levels and this can be observed in the [redacted] In proposing our [redacted] As such the costs are efficiently grounded in the activity which we have undertaken historically and with a reasonable degree of confidence in the unit rate of activity.

For 132kV, because the volumes of these are low in RIIO-ED1, and historically sporadic, this makes forecasting volumes and costs extremely challenging. We are therefore proposing for RIIO-ED2 that, because uncertainty applies to both the unit rate as well as the [redacted] volumes, these are dealt with as part of [redacted] with zero materiality. Again, and as previously stated, we would expect that we would be allowed to forecast the costs required and include these in our annual price setting process as per the overarching features set out in section 3 of this document.

Given the overall level of cost here, it is important that fast acting and agile uncertainty mechanisms are providing timely remuneration ensuring cashflow and financeability issues are not incurred in the period of RIIO-ED2.

Table 4.3.6: Diversions for wayleaves costs and volumes proposals included for final business plan

Activity and Voltage		Treatment	Costs and volumes in RIIO-ED2					Cost in ex-ante [redacted] / UM (M13)
			2023 /24	2024 /25	2025 /25	2026 /27	2027 /28	
Diversions for wayleaves terminations (ex-ante proposal)	LV	Ex-ante	[redacted]					
	HV	Ex-ante						
	EHV	Ex-ante						
	132kV	Ex-ante						
		Sub total						
Diversions for wayleaves terminations (uncertainty mechanism proposal)	LV	Annual volum driver (zero materiality)						
	HV	Annual volum driver (zero materiality)						
	EHV	Annual volum driver (zero materiality)						
	132							
		Total[13]	£3.4m	£3.6m	£4.1m	£4.1m	£4.2m	£19.5m

4.3.2.4 Diversions for highways (funded as detailed in New Roads and Street Works Act [NRSWA])

For completeness and given that the activities covered in sections 4.3.2.1 to 4.3.2.3 are all included in the same CV table within the BPDT (CV5), we are proposing that diversions for highways (funded as detailed in NRSWA) are included in baseline (ex-ante) allowances and not through the application of an uncertainty mechanism. This is because, through our effective stakeholder engagement with relevant parties, we consider we have a robust view of the efficient cost level.

[12] Rounding discrepancy

[13] Rounding discrepancy

4.3.3 Cost treatment in our final business plan

Table 4.3.7 below summarises our proposals by area and by voltage level where appropriate. It also sets out the total split between ex-ante (baseline) and uncertainty mechanism costs that we have estimated and based our final business plan on.

Given that the majority of our proposals are to include the costs in uncertainty mechanisms, it is clear that this de-risks these activities for consumers. Under our proposals, consumers will only pay for volumes experienced.

Additionally, we have also only included ex-ante (baseline) allowances where the volume and costs are certain and in a limited number of areas ensuring that the balance of risk is fair for the period between consumers and the company.

However, all of the proposals are based on the assumption that the agile and fast acting uncertainty mechanisms we have included in this document as well as the overarching features set out in section 3 are allowed for in the regulatory settlement and agreed as part of our price control determination.

This assumption of fast-acting uncertainty mechanisms means that any deviation from the approaches set out, and specifically around remuneration, would mean that the company is not remunerated in a timely enough manner resulting in cashflow and potentially financeability issues, or meaning activity is delayed. Should this be the case and a volume driver or suitable uncertainty mechanisms are not agreed and included in our draft and final settlement, one remediation that would be needed would be additional ex-ante allowances of upwards of £55.0m to be included in our settlement to cover all [redacted] costs in the RIIO-ED2 period. This is in addition to our proposal at final business plan to include £18.3m in ex-ante (baseline) allowances.

Table 4.3.7: Forecast costs and volumes by UM for wayleaves and diversions activities covered in this section

Activity		Treatment	Costs in baseline (ex-ante) [redacted]	Costs in uncertainty mechanism (M13)
Wayleaves and Easement compensation claims (excluding development claims)	LV	Annual volume driver (zero materiality)	[redacted]	[redacted]
	HV	Annual volume driver (zero materiality)	[redacted]	[redacted]
	EHV	Ex-ante	[redacted]	[redacted]
	132kV	Ex-ante	[redacted]	[redacted]
		Sub-total	[redacted]	[redacted]
Wayleaves and Easement compensation claims (development claims only)	All	[redacted]	[redacted]	[redacted]
		Sub-total	[redacted]	[redacted]
Diversions for wayleaves terminations	LV	Ex-ante plus annual volume driver (zero materiality)	[redacted]	[redacted]
	HV	Ex-ante plus annual volume driver (zero materiality)	[redacted]	[redacted]
	EHV	Ex-ante plus annual volume driver (zero materiality)	[redacted]	[redacted]
	132kV	[redacted]	[redacted]	[redacted]
		Sub-total[14]	[redacted]	[redacted]
Diversions for highways (funded as detailed in NRSWA)	LV	Ex-ante	[redacted]	[redacted]
	HV	Ex-ante	[redacted]	[redacted]
	EHV	Ex-ante	[redacted]	[redacted]
	132kV	Ex-ante	[redacted]	[redacted]
		Sub-total	[redacted]	[redacted]
		Total[15]	£18.3m	£55.0m
			£73.3m	

[14] Rounding discrepancy

[15] Rounding discrepancy

4.4 Ash Dieback

4.4.1 Introduction

Ash dieback is one currently active known tree disease in the United Kingdom and is caused by a fungus named *Hymenoscyphus fraxineus*. As the disease causes the trees to decay and become more brittle, any tree within falling distance of a line can become a risk to network resilience and result in power cuts to consumers, therefore a volume and programme of work to manage these diseased trees in RIIO-ED2 was specifically included in the baseline (ex-ante) of our draft business plan at a cost of [redacted]

It is certain that there will be an increase in vegetation cuts per year in RIIO-ED2 with this increase due to the management of the ash dieback trees (for which this type of work was not carried out in any significant volume in RIIO-ED1). The removal of diseased trees is estimated to see volumes increase by an estimated [redacted] in RIIO-ED2. However, the outturn of exactly how many trees will need removing is uncertain and could be more or less than the estimated [redacted] trees.

The ENA and all DNOs agreed to collect data on the presence of ash trees and specifically ash dieback to inform intervention plans for RIIO-ED2. The estimated volume of ash dieback related works has been based on a survey of circa 30,000 spans, which is a reasonable sample of the total population. The Ash Tree Health Class Matrix of the 30,000 OHL spans that have been inspected is shown in Table 4.4.1.

Table 4.4.1 Ash Health Class Matrix

Decay Class	Inspect in line with tree management policies	Increased arboricultural inspection and possible arboricultural work	Detailed and specialist arboricultural inspection and / or Arboricultural work	Fell or remove
Ash health class 1	[redacted]			
Ash health class 2				
Ash health class 3				
Ash health class 4				

The inspection of the spans and their health has been extrapolated to estimate the total numbers of ash trees and spans affected on our network and the intervention rate required in RIIO-ED2. The data collected from the inspections have produced the results shown in Table 4.4.2 and with the current data sample extrapolated to the full network it has been estimated that there will be [redacted] trees at class 4 which will require felling in RIIO-ED2.

However, this is a forecast and, whilst we are confident that the estimations are as accurate as possible (given the information known to date), there is inherent uncertainty on the number and health classification/status of the ash trees estate in our operating area.

Table 4.4.2 ENWL Ash Dieback Trees Class Volumes

Decay Class	Sample data		Pro-rated to full network	
	Spans	Number trees	Spans	Number trees
Class 1 – 100% - 75% canopy	[redacted]	[redacted]	[redacted]	[redacted]
Class 2 – 75% - 50% canopy	[redacted]	[redacted]	[redacted]	[redacted]
Class 3 – 50% - 25% canopy	[redacted]	[redacted]	[redacted]	[redacted]
Class 4 – 25% - 0% canopy	[redacted]	[redacted]	[redacted]	[redacted]
Decay – class unknown	[redacted]	[redacted]	[redacted]	[redacted]
Total	**2,481**	**4,867**	**15,254**	**30,040**

4.4.2 Our proposal

Given that there is uncertainty in the volume of ash dieback vegetation management in RIIO-ED2, and that future regulatory returns will include actual data from activity undertaken, we are proposing that costs and activities for Ash Dieback tree felling in RIIO-ED2 are dealt with through a volume driver uncertainty mechanism. This could apply commonly to all DNOs given that ash dieback is an issue that is facing the sector as a whole.

We are proposing that given the uncertainty is in relation to volume, a volume driver applying annually is the best and most appropriate way to manage the uncertainty for the RIIO-ED2 period.

Having further reviewed the information available to us, and considering the additional information we have obtained, we are proposing that the volume driver is based on a cost of [redacted] per tree felled in RIIO-ED2. This results in a total cost of [redacted] for estimated volumes of [redacted] in RIIO-ED2. Table 4.4.3 below summarises this.

Table 4.4.3 ENWL Ash Dieback Trees costs and volumes for final plan submission

Area	Summary
Volume (class 4 ash dieback ash trees felled)	[redacted]
Forecast total cost for RIIO-ED2	[redacted]
Unit cost (per class 4 ash dieback ash trees felled)	[redacted]
Treatment	All volume driver (uncertainty mechanism)

Additionally, we are proposing the volume driver only applies to the worst classified trees aligning with our draft business plan submission. Therefore, only trees with Class 4 decay classification would be included in the volume driver. Again, this is consistent with our draft business plan submission but with the treatment moved to a volume driver as opposed to an ex-ante (baseline) ask for investment.

The use of a volume driver provides risk protection for customers in the scenario that our extrapolated volume based on our survey results has overestimated the activity needed in RIIO-ED2. Additionally, should an increased volume be required because of an underestimation of the volume or through increased disease spread, then the company has a mechanism by which this crucial activity can continue, avoiding the customer impact of failure to deal with class 4 ash trees near overhead lines in RIIO-ED2. Finally, because we are proposing that this only applies to the worst affected trees, this protects customers from activity that isn't required, but ensures that the company is managing the impact and effects of ash dieback on our network.

Additionally, we are proposing that, as the company will be surveying and completing work in RIIO-ED2, this can provide the evidence for supporting the volume driver on an annual basis through the RRP.

To summarise our proposal for Ash dieback treatment in RIIO-ED2 is:

Area	Our proposal
Mechanism type	Volume driver (annual) – annual volumes multiplied by unit cost
Unit cost	[redacted] per class 4 tree felled
Covering	Costs of managing decay class 4 ash trees in RIIO-ED2
Excluded	Vegetation management of ash trees with decay class of 1,2,3, or unknown in RIIO-ED2. BAU vegetation management activity not associated with ash trees with decay class 4
Materiality threshold	Zero, all volumes included on an annual basis
Regulatory reporting and evidence	Included in RRP and AIP (or equivalent in RIIO-ED2) frameworks.
End Date	None – to apply for whole of RIIO-ED2

4.4.3 Cost treatment in our final business plan

Given the uncertainty around the volume of vegetation management for ash dieback in RIIO-ED2, we are proposing that all the cost is treated through an UM removing this from our baseline (ex-ante) proposal. In considering the UM design for ash dieback and the additional information we have gained for final business plan submission, the estimated total cost for this activity has been revised to [redacted] based on [redacted] trees felled in RIIO-ED2. This is summarised in the table 4.4.4 below, repeated from earlier in the section, for ease of reference.

Also, for ease of reference, the costs for ash dieback have been included in BPDT table "M13 – uncertainty mechanisms" for final business plan submission and removed from table CV29 given that our proposal for final business plan submission is for UM treatment as opposed to ex-ante funding.

Table 4.4.4 ENWL Ash Dieback Trees costs and volumes for draft and final plan submission

Area	Summary
Volume (class 4 ash dieback ash trees felled)	[redacted]
Total cost for RIIO-ED2	
Unit cost (per class 4 ash dieback ash trees felled)	
Treatment	All volume driver (uncertainty mechanism)

This is on the assumption that an agile and fast acting uncertainty mechanism based on the proposal we have included in this document as well as the overarching features set out in section 3 of this document is allowed for in the regulatory settlement and agreed as part of our price control determination.

This assumption of a fast-acting uncertainty mechanism means that any deviation from this approach, specifically around timely remuneration, would mean that the company is not remunerated in a timely enough manner resulting in cashflow and potential financeability issues, or meaning activity is delayed. Should this be the case and a volume driver or suitable uncertainty mechanism is not agreed and included in our draft and final settlement one remediation would that an additional £17.1m will need to be included in our baseline (ex-ante) settlement to cover updated ash dieback related vegetation management costs in the RIIO-ED2 period.

4.5 PCB

4.5.1 Introduction

The Environmental Protection (Disposal of Polychlorinated Biphenyls and other Dangerous Substances) (England and Wales) (Amendment) Regulations 2020 came into force on 1 July 2020.

These regulations implement Regulation (EU) 2019/1021 of the European Parliament and of the Council on persistent organic pollutants (recast) and require that equipment containing more than 0.005% (50ppm) but no more than 0.05% (500ppm) by weight of PCBs; and a total volume of more than 0.05dm (50ml) of PCBs may be held until the end of 31st December 2025.

Equipment is only classed as being PCB contaminated at concentration levels above 50 ppm.

Although ENWL (and its predecessor companies) never sourced PCB-filled equipment, some contamination could and has occurred due to cross contamination in the manufacturing process.

Environment Agency (EA) guidance is that it must be assumed that all ground mounted transformers (GMTs), and pole mounted transformers (PMTs) 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.

We have no satisfactory technique for the decontamination of GMTs. Additionally, the decontamination of PMTs is even more impractical and uneconomic. Our policy therefore, is that all PCB contaminated transformers will be replaced and disposed of appropriately by 31 December 2025.

Whilst some PCB contaminated, or potentially contaminated, transformers will be replaced due to their condition, or as part of other pro-active programmes, a separate programme of testing and replacement is required to enable us to comply with the legal deadline to no longer hold PCBs by 31 December 2025.

The only suitable techniques available to ensure compliance with the EA's regulatory completion date are a combination of oil sampling and testing and the use of a statistical model. These are the techniques by which we will identify PCB contaminated transformers and hence implement a replacement programme.

4.5.2 Ground mounted transformers

Currently, there are [redacted]n-service ground mounted distribution transformers that were manufactured prior to 1987. Of these GMTs, [redacted] have had PCB tests carried out, [redacted] of which are PCB contaminated and will be removed during RIIO-ED1.

The number of in-service transformers not yet tested for PCBs is [redacted] Around [redacted] transformers are scheduled to be sampled and tested before the end of RIIO-ED1. Using these values, the remaining number of our ground mounted transformers to be sampled and tested in RIIO-ED2 is approximately [redacted]

Based on the results of all GMT testing undertaken to date, including transformers removed in previous years, we estimate that [redacted] of the remaining [redacted] untested GMTs will be identified as having PCB levels greater than 50 ppm. It is possible however that some of these will be replaced irrespective of PCB levels due to asset health, load replacement or loss reduction programmes of work. At this stage though we are unable to identify which GMTs this might apply to and the consequent number of replacements that would be solely for PCB-contamination reasons. Therefore, the volume of GMTs we need to replace for PCB reasons is uncertain. For the purpose of this Annex, we have estimated that [redacted] GMTs will need to be replaced for PCB reasons.

4.5.3 Pole mounted transformers

The most effective way to establish the PCB content of oil in equipment is to take an oil sample and test it in a laboratory to establish its PCB level. However, whilst practical for GMTs, oil samples cannot reasonably be taken from in-service PMTs for the following reasons:

- Most PMTs are sealed units and therefore do not have sampling points;
- Opening up a PMT to obtain an oil sample risks introducing contamination (e.g. rust) into the transformer, increasing the risk of failure;
- There is a risk of environmental contamination due to spillage if the transformer tank is opened; and
- The overhead line would have to be taken out of service twice; once for a sample to be attempted and then again to replace any PMTs found to be contaminated, thereby increasing customer disruption.

In conjunction with the other DNOs, we have been working through the Energy Networks Association (ENA) PCB Cohort Group to investigate and develop techniques for identifying the PCB content of transformer oil without scrapping all pre-1987 PMTs. Through this work a statistical model has been developed to determine whether cohorts of PMTs (by manufacturer and year of manufacture) can be identified as being PCB negative (i.e. a PCB content of not more than 50 ppm) and the EA has agreed through a Regulatory Position Statement (RPS) that transformers that can be shown to be PCB negative (i.e. 50ppm or less) using this statistical model can be left in service until the normal end of their life.

This statistical model is currently the only practicable method by which the PCB contamination or otherwise of PMTs can be assessed. It has been agreed by the EA as the only approach they will accept to allow PMTs to be left in service without an oil sample and PCB test.

Using the statistical model, the number of our PMTs anticipated as requiring replacement before the end of 2025 due their PCB content is in the region of [redacted] However, there is considerable uncertainty around this volume as the statistical model continues to be updated on a quarterly basis as more data is submitted by DNOs into the ENA modelling.

4.5.4 Additional equipment

In addition to transformers, we know that PCBs have sometimes been found to occur in other types of equipment, some of which is integral to other larger pieces of equipment.

Examples of these types of equipment are as follows:

- Voltage regulators (pole and ground mounted)
- Voltage Transformers
- Shunt reactors
- Capacitors in tap-changer mechanisms
- Power factor correction capacitors
- Capacitors associated with lift/hoist motors
- Lighting ballasts
- Contactors in old street lighting fifth core timers/controls
- Air-blast CB grading capacitors
- Switchgear bushings
- CT chambers
- Busbar and cable end boxes

We have identified Voltage Transformer (VTs) in our network that may contain PCBs, and these have been registered with the EA. With regards to the other types of equipment, industry knowledge on their potential contamination is limited and we are working along with the rest of the industry to identify which, if any, of these items we hold, that could be classed as contaminated equipment and therefore might require removal.

4.5.5 Our proposal

Given the uncertainties set out above in terms of the volumes and location of PCB-contaminated GMTs, and the ongoing updating of the statistical model for PCB-contaminated PMTs, we are proposing that costs and activities for the removal of PCB-contaminated assets in RIIO-ED2 is dealt with through an annual volume driver uncertainty mechanism, based on the annual volumes forecasted and delivered by DNOs via the RRP process. This is in line with our overarching features for UMs as set out in section 3.

We consider a volume driver is a suitable mechanism, given that replacement of PCB-contaminated transformers is a business as usual activity in RIIO-ED1 and the units costs are clear as DNOs already undertake the activity of replacing transformers. The unit cost risk therefore resides with the DNO where we have proposed a unit cost. Further, as this is a compliance activity, volumes required will be as a result of what is set out in legislation and as per determined by testing or based on the asset modelling agreed by the sector and the ENA.

We propose that the mechanism runs for the whole of RIIO-ED2 in order to manage the risk of the identification of further, as yet unknown, PCB contaminated assets as well as potential supply chain issues in sourcing replacement assets. For assets yet to be identified, as set out above in our list of [redacted] should be in place at the end of RIIO-ED2. The rules for [redacted], and what evidence will be required, need to be set out before the price control starts.

For clarity, we propose that this PCB mechanism only applies to assets that would not have been replaced as part of any other programme of work e.g. fault/condition replacement, loss reduction, load-related.

To summarise, our proposals for treatment of PCB-contaminated assets in RIIO-ED2 is:

Area	Our proposal
Mechanism type	Volume driver (annual) for GMTs and PMTs Logging up for other equipment identified as PCB-contaminated before or during RIIO-ED2
Unit cost	[redacted] per GMT tested [redacted] GMT replaced [redacted] PMT replaced – this includes an element of selective upsizing as set out in our Engineering Justification Paper ENV EJP1 and associated cost benefit analysis.
Covering	Replacement of PCB contaminated GMTs and PMTs Replacement of other PCB-contaminated assets not yet identified
Excluded	Replacement of PCB-contaminated GMTs identified as part of asset health, low-loss or load replacement programmes Replacement of PCB-contaminated PMTs for condition-based reasons
Materiality threshold	Zero, all volumes included on an annual basis
Regulatory reporting and evidence	As reported in RRP and AIP (or equivalent in RIIO-ED2) frameworks.

4.5.6 Cost treatment in our final business plan

Given the uncertainty around the volumes of PCB contaminated equipment needing to be replaced in RIIO-ED2, we are proposing that all replacement cost is treated through an uncertainty mechanism, removing this from our baseline (ex-ante) proposal. The estimated total cost for this activity is [redacted] based on [redacted] GMTs and [redacted] PMTs being replaced in RIIO-ED2 but, for the reasons set out above, these volumes are highly uncertain. These costs have been included in BPDT table "M13 – Uncertainty Mechanisms" for final business plan submission and removed from table CV22 given that our proposal for final business plan submission is for UM treatment as opposed to ex-ante funding.

4.6 Enabling Net Zero – NZARD and Distribution Net Zero fund

4.6.1 Introduction/Issue

Within Ofgem's Decarbonisation Action Plan[16], Action 1 clearly lays out the intention to "*make the network price control regulatory regime more adaptive to deliver the most effective transition at lowest cost.*"

Ofgem recognised in its Final Determinations[17] for the earlier RIIO-2 sectors of Gas and Transmission that the price control needed to be flexible enough to inject the necessary funding, at the right time, to support the achievement of Net Zero. This aim applies equally to the Electricity Distribution sector.

One way to achieve this aim is by the provision of use it or lose it (UIOLI) allowances, where a need is identified but there is uncertainty over the volume and cost of the activity. These can provide companies with allowances and flexibility in delivering activities whilst protecting customers by setting an overall cap and ensuring that any unspent allowances are returned to customers.

In the case of any UIOLI allowance, TIM should not apply to under or overspends as the allowance is non-transferable. Any underspend is clawed back, and any overspend is borne by the company. For clarity, none of these two UIOLI allowances (DNZ and NZARD) are included in our ex-ante (baseline) allowance proposals in this our final business plan and are shown in table M13 for Uncertainty Mechanisms.

4.6.2 Net Zero fund (NZARD)

Within the RIIO-GD/T2 Final Determinations, Ofgem introduced the Net Zero and Re-opener Development (NZARD) UIOLI allowance, to enable Net Zero related development work and small value Net Zero facilitation projects.

We consider that the same requirement exists in ED as with the other licensed sectors, and therefore propose that the NZARD is also introduced into the RIIO-ED2 framework to be applicable for all licensees. We have forecast a value of £11.4m as requirement under this mechanism which is made up of:

- £1.4m Local Area Energy Plan (LAEP) support as shown in our DSO Transition Plan (Annex 2)
- £6.0m Re-opener development
- £4.0m provision for small Net Zero facilitation projects which come forward in period

We propose that the early development work on the following re-openers should be included in this mechanism:

- Net Zero Re-opener
- Load Related Re-opener
- Moorside Re-opener
- High Value Projects Re-opener
- Rail Electrification Re-opener

[16] https://www.ofgem.gov.uk/publications/ofgems-decarbonisation-action-plan
[17] RIIO-2 Final Determinations for Transmission and Gas Distribution network companies and the Electricity System Operator | Ofgem

Area	Our proposal
Mechanism type	Use it or lose-it allowance
Covering	LAEP support, Net Zero facilitation projects and early development work on projects that licensees intend to bring forward under specific re-openers
Value of fund	£11.4m
Cap	£2m per project
Eligibility	Governance document to be developed, broadly in line with existing for GD/T
Monitoring	Via regulatory reporting

4.6.3 Distribution Net Zero Fund (DNZ)

In our draft plan, we proposed a range of activities to support the Net Zero transition. In particular our proposals to help others on their decarbonisation journey, ensuring that we contribute towards a just transition, ensuring that no one is left behind and, where particular groups may need more support, how we propose to address this.

Since our draft plan was published, we have continued our stakeholder engagement and looked more widely to see where we can learn from others. We have seen the success that SPT had with their Green Economy Fund in RIIO-T1, and noted the bespoke fund provided for RIIO-T2 as well as the proposal from SPEN for a Distribution Net Zero (DNZ) Fund for RIIO-ED2.

We consider that the introduction of a DNZ Fund for RIIO-ED2 on a common basis for all DNOs achieves Ofgem's aim to provide flexibility for Net Zero in the regulatory framework, whilst continuing to protect customers.

The introduction of a DNZ fund provides companies with the allowances and flexibility to seek the best outcomes for customers, whilst protecting them by ensuring that any unused allowance is returned.

We propose that each company is able to tailor the scope of their DNZ to meet the customer needs in their specific licence area and that Ofgem provides sufficient flexibility within the scope for this to occur.

We propose our DNZ is comprised of two key activities as these are the ones that we consider most beneficial to customers in our area, and we are best placed to deliver:

- Community energy fund - £3.2m
- Decarbonisation support - £1.7m

Further details on the identification, stakeholder support and delivery of these activities can be found in Annex 5.

Area	Our proposal
Mechanism type	Use it or lose-it allowance
Covering	Community energy fund and Decarbonisation support
Value of fund	£4.9m
Monitoring	Via regulatory reporting

Should the NZARD and the DNZ not be agreed as part of our draft and final settlement, one remediation required would be that the costs be included in our baseline (ex-ante) settlement to cover these activities in the RIIO-ED2 period.

4.7 Moorside – Nuclear development on the west coast of Cumbria

An update to our existing bespoke uncertainty mechanism (for RIIO-ED1) is needed given the changes around the timing and form of nuclear development on the west coast of Cumbria in RIIO-ED2. In RIIO-ED1 it was envisaged that a large single nuclear power station (assumed as 3.6GW) was the only development scenario that was needed to be covered by the Moorside uncertainty mechanism. In RIIO-ED2, this isn't the case with the advent and progression of more modular nuclear technologies supported by the UK Government and private enterprise. Small modular reactors (SMR) could impact on the type of connection and the solution needed to accommodate the nuclear development on our distribution network. Additionally, the trigger for accessing the Moorside uncertainty mechanism needs to be amended to cover SMR development and/or a large singular nuclear power station as this differs under the scenarios envisaged.

Appendix C sets out the details behind these required updates and reflects our proposals on what is needed to ensure that the Moorside mechanism is fit for purpose to cover the RIIO-ED2 period.

Our proposed updates to the Moorside uncertainly mechanism for RIIO-ED2 are based on the information and regulatory framework known at the time of drafting. Given that decisions from Ofgem are pending on items that could impact the uncertainly mechanism design for Moorside, we suggest that we work with Ofgem between now and Final Determination to ensure a mechanism reflective of the final regulatory framework for RIIO-ED2 and the uncertainty of nuclear development on west coast of Cumbria is secured.

Potential areas of impact include, but are not limited to:

- The access and forward-looking charges significant code review (SCR)
- Other reforms under SCR
- Changes to charging rules under CUSC
- Final design and implementation of load related expenditure mechanism for RIIO-ED2
- Ofgem decision on high value projects criteria for RIIO-ED2
- Decisions on government support for nuclear development

We are open to working with Ofgem on the revisions to the mechanism '*CRC 3L. Arrangements for the recovery of Moorside Costs*' as proposed in this document between final business plan submission and final determination if required.

5. Our proposals to help shape Ofgem planned uncertainty mechanisms

In order to help shape new uncertainly mechanisms which Ofgem has proposed for RIIO-ED2, we share here our proposals for how these re-openers should work. Additionally, to support continual improvement and evolution and to ensure that the existing RIIO-ED1 uncertainty mechanisms proposed for inclusion in RIIO-ED2 are fit for purpose we have proposed some changes to these mechanisms as well. The areas and section references are summarised in the table 5.1 below.

Table 5.1: Ofgem planned uncertainty mechanisms for RIIO-ED2 and our proposals

Area	Type of Uncertainty Mechanism	Existing or new for ED2 (as proposed by Ofgem)	Section
Net Zero	Re-opener	New	Section 5.1
Electricity System Restoration	Re-opener	New	Section 5.2
Environmental Legislation	Re-opener	New	Section 5.3
Access SCR reform – Our proposal 'Regulatory Driven Change' re-opener	Re-opener	New	Section 5.4
DSO	Re-opener	New	Section 5.5
Specified Street works	Re-opener	Existing	Section 5.6
Smart Meter Rollout costs	Volume Driver	Existing	Section 5.7
New Transmission Connection Charges (NTCC)	Re-opener	Existing	Section 5.8
High Value Projects	Re-opener	Existing	Section 5.9
Cyber Resilience	Re-opener	New	Section 5.10
Return Adjustment Mechanism (RAM)	Other	New	Section 5.11

5.1 Net Zero re-opener

We note the decision[18] by Ofgem to introduce a Net Zero re-opener for RIIO-ED2 and agree with the inclusion of such a mechanism. We also note that the scope, materiality threshold, timing and ability to trigger has not yet been decided for and will be consulted on at Draft Determination stage.

5.1.1 Scope

We propose that the Net Zero re-opener should have the same scope as has been defined for the other RIIO-2 sectors, namely, a Net Zero Development has occurred or is expected to occur; such development is expected to vary costs within the period; and the effect is not otherwise provided for or been assessed under another re-opener.

Net Zero Development is defined for GD/T as:

[A] change in circumstances related to the achievement of the Net Zero Carbon Targets that is:

(a) a change in national government policy (including policies of the devolved national parliaments);

[18] SSMD Overview table 3

(b) a change in local government policy;

(c) the successful trial of new technologies or other technological advances;

(d) a change in the pace or nature of the uptake of low carbon technologies; or

(e) a new obligation arising from the agreement of a Local Area Energy Plan or an equivalent arrangement

A live example of circumstances where it might be necessary to trigger the Net Zero reopener is reform of planning requirements for distribution Net Zero infrastructure. The Energy Networks Association (ENA) is actively engaging with stakeholders including Government on the potential benefits of this where there is a possibility that additional costs and time impacts may be caused to some consumers in meeting their Net Zero needs if reforms aren't implemented.

5.1.2 Other arrangements

We note that Ofgem has decided for GD/T that this re-opener may be triggered at any point in the price control period, be triggered solely by Ofgem, and that has a materiality threshold in line with overarching features.

We propose that DNOs should also be able to trigger this re-opener, as they are better placed to analyse the impact of Net Zero Development on their activities and costs and are therefore able to provide Ofgem with the information and any resulting re-opener application.

We also consider that this should have an annual window at a time in line with overarching features to provide Ofgem and companies with structure and reasonable notice.

Finally, as all of the Net Zero Developments are outside of DNO control, that materiality threshold for this re-opener should be zero. This is consistent with other re-openers which are entirely outside of the company control such as Physical Site Security or Cyber.

Area	Our proposal
Mechanism type	Re-opener
Covering	Net Zero Development as currently defined for RIIO- GD/T2
Trigger	Ofgem and DNO
Timing	Annually each January
Materiality threshold	Zero

5.2 Electricity system restoration (black start)

Ofgem has proposed that costs associated with Energy System Restoration (ESR) are provided for through baseline allowances, with a re-opener to adjust revenues to cover the costs of workload changes in response to changes in the mandatory resilience period or additional activities that may arise from new obligations once the ESR standard is in place.

We agree that the treatment as ex-ante baseline allowances with a re-opener is the right treatment for RIIO-ED2.

We have put forward our baseline costs within our plan. The costs associated with meeting the new standard will be those such as colleagues in our Control Room, and therefore the costs are shown within the Closely Associated Indirects (CAIs) table.

In line with other re-openers that are entirely outside of DNO control, we consider that this should have zero materiality threshold, as with those such as Physical Site Security and Cyber.

We are also aware of work that the ESO is undertaking with their Network Innovation Competition (NIC) Distributed ReStart[19] project looking at how distributed energy resources (DER) can be used to restore power to the transmission network in the unlikely event of a blackout. This project was due to end in March 2022, but has been delayed by a few months to June 2022, and therefore it is unlikely that any resulting requirement for DNOs will be fully known ahead of RIIO-ED2 Final Determinations.

Whilst it is too early to determine the outcome or recommendations from the project, it is likely that any recommendations will result in a change of activity for DNOs. We propose therefore that the scope of the ESR re-opener includes additional activities required by DNOs flowing from or influenced by the outcome of the Distributed ReStart project. We consider that the current wording in the SSMD[20] "*or additional activities that may arise from new obligations once the ESR standard is in place*" already covers this circumstance however have stated this explicitly for the avoidance of doubt.

5.3 Environmental legislation

We are supportive of the environment legislation re-opener provisions as set out in the RIIO-2 Sector Specific Methodology Decision – Annex 1.

We note that the scope at present is written as "*responding to environmental legislation that requires a material change in the approach to companies' EAPs. The scope will be activities which relate to the decarbonisation of the networks and the wider impact of DNOs' activities on the environment.*"[21]

Based on our experiences in RIIO-ED1 and previous price controls we generally see changes that would materially affect these activities as falling into one of three categories:

- Introduction of new legislation
    - e.g. the potential SF6 change to F-Gas regulations
- Change of enforcement practice or legislative clarification
    - e.g. PCB requirement
- Change to /new standards which are imposed by external bodies
    - e.g. Environment Agency/Health Safety Executive

It is therefore important that the scope is not limited to purely new legislation, but also covers changes to enforcement practices, removal of derogations, and changes which are imposed by other external bodies.

We also consider that the re-opener should not be tied to only those activities that are contained within the EAP. If it was limited this would preclude any new requirement that is not already in place and extension not in the current scope of the EAP.

We suggest therefore that the scope should be:

"A re-opener for responding to new, or changes to, environmental compliance requirements that will materially impact companies' activities. The scope will be activities which relate to the decarbonisation of the networks and the wider impact of DNOs' activities on the environment."

[19] [What is the Distributed ReStart project? | National Grid ESO]
[20] SSMD Annex 1, Chapter 8, Para 8.137
[21] SSMD Annex 1, Chapter 9, Para 9.30

Whilst the description references material changes, it should be noted that any change is likely to be material but, in isolation, may not always meet the common materiality threshold for re-openers.

As this re-opener is being developed to deal with an uncertainty related to external change outside of DNO control, we propose that this re-opener should have a zero-financial materiality threshold, which is in line with Cyber and Physical Site Security.

As regards timing, we originally considered annual windows, as such changes could occur any time in the period. However, to manage workload and Ofgem intervention, we have instead suggested two windows, in years 2 and 4.

We are aware that potential removal of RPS211 related to contaminated spoil from street works could be included in this re-opener, although our proposal is that this is included in the street works re-opener set out in section 5.6. The reason for this is that one or more DNOs triggering the street works re-opener is likely during the ED2 period, so it is more efficient for Ofgem and its stakeholders to bundle RPS211 additional costs into the street works re-opener.

Area	Our proposal
Mechanism type	Re-opener
Covering	Response to new, or changes to, environmental compliance requirements that will materially impact companies' activities. The scope will be activities which relate to the decarbonisation of the networks and the wider impact of DNOs' activities on the environment
Trigger	DNO
Timing	Years 2 and 4
Materiality threshold	Zero

5.4 Access and SCR reforms – Our proposed 'regulatory driven change' re-opener

5.4.1 Introduction

We are entering a period of increasing change and responsive policy development by Ofgem and though Ofgem's implementation of Government policy. We have also seen direct implementation of Government policy by government enacting licence changes, a key recent example being the implementation of the Clean Energy package. We are strongly supportive of achieving Net Zero at least cost and many of the pending decisions by Ofgem and other policy makers are aligned with this goal. A range of changes to modernise the energy system, not necessary clearly linked to Net Zero, are likely and this proposed mechanism enables their smooth implementation (e.g. DUoS reforms, Mandatory Half Hour Settlement).

When making decisions that are increasingly whole system and consumer-focussed it is possible that increased costs, not included in final business plans, may be incurred by DNOs. It would not be in consumers' interests for us to include these costs in baseline allowances because the outcomes of the decisions are currently uncertain, and the costs are also uncertain. However, it is also the right balance between consumers and companies that the efficient costs of delivering the DNOs' parts of the regulatory driven change agenda, where these result in additional costs not included in final business plans, can be applied for and considered by Ofgem during the price control.

5.4.2 Proposal

We set out below our proposals for a 'regulatory driven change' re-opener setting out why this better addresses the issues/risks than a limited Access and forward-looking charges SCR re-opener as well as setting out the details of how it would work for RIIO-ED2.

5.4.2.1 Issue/Risk

This purpose of this re-opener would be to ensure that DNOs are funded for costs efficiently incurred as a consequence of regulatory or policy change, that have not been included in baseline allowances.

We suggest that the scope of any request for additional costs is linked to the outcome of an Ofgem Significant Code Review change, a Decision under any industry code, or a Licence or Guidance change where Ofgem is currently the decision maker. Government led change initiatives would also be within scope, with the implementation of the Clean Energy Package (CEP) as an example.

It is important that the scope of this mechanism is not limited solely to changes made to DNOs' own licences but also includes the increased costs of DNOs working with other parts of the wider energy and whole system if Ofgem or Government policy impacts these. The key determinant is that Ofgem or Government (or a successor body appointed by these) implements a change that leads to increased DNO costs that were not included in final business plans.

This is an industry-wide issue and the introduction of this mechanism will enable all DNOs to respond quickly and fully to Ofgem policy decisions in the confidence that efficient costs will be recovered. It will also ensure that the costs requested by DNOs will be better specified, based on more accurate information than is available at final business plan submission and can reflect yet-to-be-made Ofgem/government decisions, thus reducing the risk to customers of DNOs being funded for regulatory-driven changes that are currently difficult to quantify.

Should Ofgem or Government powers be devolved to Code Managers as a result of the industry code reform work that Ofgem and BEIS are undertaking then these changes are also included in scope. Should the FSO undertake a role that enables it to make decisions in the scope currently reserved for Ofgem and Government then these also should be included.

5.4.2.2 Probability

Given the rapid pace of change in the industry as we progress towards Net Zero we consider that there is a very high probability that DNOs will face currently unknown/un-forecasted costs. Examples of regulatory or policy change covered by our proposed re-opener include, but are not limited to;

- implementation of the Access SCR decision
- establishment of the FSO, energy codes reform
- DUoS charging reform
- retail market reform
- mandatory half hourly settlement
- requirement to further develop digital twin technology

5.4.2.3 Materiality

At this stage it is not possible to quantify the cost impact of decisions that are yet to be made. As an example, we do know that the business costs of implementing Ofgem's Access SCR minded-to decision would be material and our submission includes some estimate of the indirect costs of that minded-to decision. However, the actual cost impact of this decision is still highly uncertain.

5.4.2.4 Design

We propose that the costs from multiple regulatory changes, whilst being separately identified, can be included in a single application in the relevant window, i.e. the relevant costs of one or more change can be combined into a single aggregate request for allowances.

The re-opener would include all indirect and direct costs except where already funded or in another re-opener funding request made by the licensee. It would therefore include all people, process and system changes, including overheads and non-operational capex such IT and telecoms.

We propose two re-opener windows during the RIIO-ED2 period; the first in January 2026 and the second in January 2028. Applications may be made on forecast costs, or a combination of actual and forecast costs. We believe the inclusion of forecast costs for known specific changes will allow companies to better manage the risks as well incentivising them to continually seek efficiencies in order to deliver Totex savings for customers. We also propose that DNOs can only make one application per regulatory change, unless their initial application for a specific change is rejected either fully or partially during the first window, or the decision-making body (Ofgem/Government) makes further decisions. In such cases, DNOs should be permitted to make a further application in the second window if it is different in some way; for example, based on updated information, or information that was previously unavailable to both the company and/or Ofgem.

As set out in our position on overarching features for re-openers, this mechanism should have a zero-materiality threshold as the driver of uncertainty is of a legislative compliance nature and therefore outside of management control.

5.4.3 Cost treatment in our final business plan

Area	Our proposal
Mechanism type	Re-opener
Covering	Uncertain incremental costs incurred as a result of Ofgem or Government Regulatory-driven change
Trigger	Licensee
Timing	January 2026 and January 2028
Materiality threshold	Zero

Given the uncertainty around the timing and impact of regulatory-driven change during RIIO-ED2, we propose that all currently anticipated costs are treated through this uncertainty mechanism removing this from our baseline (ex-ante) proposal. Our best view of the indirect cost impact of the Access SCR decision is currently included in Table M30. We have not included any estimates for future costs of any other regulatory driven changes as we do not have sufficient clarity at this stage.

5.5 DSO

Ofgem confirmed in its SSMD for RIIO-ED2 that it intended to undertake a programme of work to review the governance arrangements DSO, including considering the risks of path-dependence and the needs-case for further separability of DSO. The work is also intended to identify and develop the tools Ofgem would need to enact or enable any decision on separation or separability. Ofgem states that in this instance it would consult on a DSO re-opener or other tool before the start of RIIO-ED2.

Our view remains that the RIIO-ED2 period is the time for DNOs to develop and hone the tools and techniques needed to fulfil the new DSO functions and activities and should not be the time to consider fundamental restructuring of the industry, particularly with the FSO review currently taking place and pressing Net Zero transformation actions that should not be delayed. There are other regulatory approaches available to Ofgem that would be more proportionate than revised industry structure arrangements, including Ofgem setting the requirement of baseline expectations within DNOs' RIIO-ED2 strategies and plans and monitoring these as required.

Whilst we consider that the arrangements we are proposing in our business plan to manage real or perceived conflicts of interest, including functional separation and independent oversight, are appropriate at this point, we also consider it prudent to include a DSO re-opener in the RIIO-ED2 framework given the potential for Ofgem to require further changes beyond baseline requirements within the period.

The ongoing full chain flexibility work currently being undertaken by Ofgem is looking at the future governance arrangements for DSO. The outcome of this and other Ofgem work and any subsequent requirements on DNOs in terms of governance and structural arrangements should form the scope of any DSO re-opener. As this re-opener is being developed to deal with an uncertainty related to external change outside of DNO control, we propose that it should have a zero-materiality threshold and should be DNO triggered. It should allow for both actual and forecast costs.

We consider that the re-opener window should be set once a decision on DSO governance has been made. The window should be a minimum of six months after Ofgem has set clear requirements for the content and considerations for any changes. We anticipate that Ofgem would publish the detail needed for DNOs to prepare the re-opener submission with or in immediate parallel with any Ofgem decision.

5.6 Specified street works costs

5.6.1 Introduction

For RIIO-ED2, Ofgem is proposing that the uncertainty mechanism for specified street works costs in RIIO-ED1 is applied and continued without change or reform. Below is the extract of the UM as set out in the ED1 price control handbook (slow-track licensees)[22]:

> "*The uncertainty mechanism for Specified Street Works Costs*
>
> *7.35 The term Specified Street Works Costs means costs incurred, or expected to be incurred, by the licensee in complying with obligations or requirements arising under any order or regulations made under Part 3 of the Traffic Management Act 2004 (or, in Scotland, the Transport (Scotland) Act 2005) that impose a permit scheme lane rental scheme or equivalent and comprise:*
>
> *(a) permit fee costs, or equivalent;*
>
> *(b) lane rental costs, or equivalent;*
>
> *(c) one-off set up costs;*
>
> *(d) administrative costs arising from the introduction of permit schemes or equivalent and lane rental schemes or equivalent;*
>
> *(e) additional costs arising from the introduction of permit conditions or equivalent,*

[22] https://www.ofgem.gov.uk/sites/default/files/docs/2017/08/ed1_handbook_v3_slowtrack_0.pdf

all as further clarified in the RIGs. This definition is set out in CRC 3F.

7.36 Specified Street Work Costs are only costs associated with a new permit or lane scheme (or Scottish equivalent). These are ones which were not operational by 1 July 2013 or where the scheme was implemented by this date but the DNO did not have 12 months of cost data relating to the scheme. Only the costs of these schemes will be considered as part of the reopener mechanism.

7.37 The uncertainty mechanism provides for relevant adjustments in respect of efficient costs that were not included in the calculation of the licensee's Opening Base Revenue Allowances."[23]

We support the continuation of a street works costs uncertainty mechanism in RIIO-ED2, but we consider that some limited changes/reforms are required to make the uncertainty mechanism fit for purpose for the period in question considering the uncertainties which are known for the RIIO-ED2 timeframe.

5.6.2 Our proposal

Without reform, the current specified street works costs uncertainty mechanism would only cover uncertainty relating to those additional costs incurred by DNOs as a consequence of new lane rental and permit schemes in the RIIO-ED2 period, including the associated costs of implementing and complying with those schemes. Whilst we agree that this element should continue in RIIO-ED2 and apply to those new/additional costs incurred in the RIIO-ED2 period, this does not cover all the uncertain elements of street works costs in RIIO-ED2.

We therefore are proposing that the street works uncertainty mechanism (re-opener and closeout) for RIIO-ED2 also cover the uncertain elements and associated costs of complying with changes to:

- Removal/withdrawal of Regulatory Position Statement 211 (RPS211) covering the treatment of contaminated spoil waste stream from utilities' street works excavations in RIIO-ED2.

Uncertainty driver of cost	Likelihood of change in RIIO-ED2	Our proposal	Commentary
RPS211 – spoil from street works excavations from utilities including DNOs	High	Hybrid regulatory approach - Baseline for DNO direct costs of new processes and testing spoil. Included in street works re-opener, plus closeout, costs for dealing with the waste stream.	Costs of managing RPS211 compliance can be assessed (e.g. our knowledge and experienced on planned work where RPS211 doesn't apply). Waste stream costs not certain enough as supply chain will need to change to deal with new waste flows.

For clarity we are also proposing that this is included as part of any street works costs dealt with at RIIO-ED2 closeout, if required.

[23] Ibid. pg. 100.

It is also clear, that on a detail level the date referred to in the RIIO-ED1 uncertainty mechanism should be updated to 1 April 2023 to reflect the uncertainty mechanism covering only new costs/schemes/impacts for the RIIO-ED2 period.

5.6.3 Cost treatment in our final business plan

Our current street works requirements are included in our baseline (ex-ante) proposal as part of our final business plan submission with the expectation that the re-opener provides for the impact of any changes, legislative or otherwise, in RIIO-ED2. If, as part of the cost assessment and benchmarking process undertaken by Ofgem, any of these costs are removed from our plan to allow like for like comparison of costs, we propose that these costs and the driver of these are also included in the scope of the street works re-opener for RIIO-ED2.

As an example, and for clarity, we propose that all DNOs include the costs of complying with changes in guaranteed standards for reinstatement duration in RIIO-ED2 (Specification for the Reinstatement of Openings in Highways [SROH]) in baseline allowances. We have included these in our baseline (ex-ante) proposals as part of this our final business plan submission. If, as part of the cost assessment and benchmarking process undertaken by Ofgem, these costs are removed from our plan to allow like for like comparison of costs, we propose that they are also included in the scope of the street works re-opener for RIIO-ED2.

5.7 Smart meter roll-out costs

Ofgem intends to continue the RIIO-ED1 smart meter volume driver into RIIO-ED2. Installation rates and the timing of such are outside of DNO control and will remain uncertain, therefore we agree that the continuation of a volume driver is appropriate for RIIO-ED2.

We have proposed some revision to the mechanism based on our learnings from RIIO-ED1. These are:

- the intervention rate at which baseline allowances are set
- the removal of the tapering factor
- operating the volume driver for the entire RIIO-ED2 price control

The costs and volumes included in our submission (see BPDT CV34) are broadly in line with those experienced in RIIO-ED1 (pre-pandemic levels). We have forecast Smart Meter Interventions up to June 2025 in line with the Smart Meter Policy Framework post 2020 and consider these figures to have sufficient certainty to allow Ofgem to use as ex-ante baseline allowances. Any variance to this forecast should be managed by the volume driver with revenues adjusted upwards or downwards to reflect actuals.

A national infrastructure programme on this scale is unprecedented and as a result, the rollout has experienced challenges resulting in the end date being moved on a number of occasions as well as additional phases added more recently. Whilst there is greater experience for suppliers and installers now, there remains the possibility that the end date may move once again. We also know that even if the end date does not formally move, suppliers will continue to install smart meters beyond the 2025 date, as not all customers will have taken up the offer by that time, and installation will continue through to the end of RIIO-ED2. As such, we propose that the Smart Meter volume driver continues to be effective through to the end of RIIO-ED2 to reflect the ongoing installations and likelihood of the need for DNOs to continue to intervene to support the smart meter rollout. We have not put in any forecasts for interventions beyond 2025 to be funded in baseline allowances as the volumes beyond 2025 are less certain. We expect that the volume driver can work to adjust revenues upwards based on actual interventions reported.

RIIO-ED1 was set with an opening allowance which assumed a 2% intervention rate against a forecast installation figure. A tapering factor was included in RIIO-ED1 to vary the unit cost should intervention rates exceed 10%. Both the installation figure and intervention rate have varied over time however we now have sufficient historical data to provide us with confidence and no DNO has come close to reaching the 10% intervention rate at which the tapering factor starts to become effective. As a result, we consider the tapering factor to be no longer required and for simplicity should be removed for RIIO-ED2.

Finally, the RIIO-ED1 volume driver mechanism was built to reflect the reality that the intervention in many cases occurs ahead of the Smart Meter being installed and a retrospective prior year's adjustment could be applied. We agree that the same approach should be taken in RIIO-ED2. In summary:

Attribute	Change from RIIO-ED1
Unit cost	As per RIIO-ED1
Tapering factor	Remove
Allowance basis	% intervention rate x unit cost
Retrospective adjustments	As per RIIO-ED1
End date	End of RIIO-ED2 period

5.8 New Transmission Connection Charges (NTCC)

In RIIO-ED1 Transmission Connection Points charges are separated by categories of "existing" (TCPs) or "new" (NTCC). Existing has the treatment of pass-through, whilst "new" are treated as part of Load Related Expenditure.

The calculation of charges is governed by charging rules in the CUSC and arise as a result of a requirement of the licensee for the provision of new or reinforced connection points between the GB Transmission System and the licensee's Distribution System. They are therefore significantly outside of the control of the DNO.

At the start of each price control period, what would be deemed to be "new" in RIIO-ED1, would adjust to become "existing" in RIIO-ED2 and therefore are only treated as LRE for the duration of the price control period in which the asset is energised. This seems a largely academic exercise and distorts the view of total transmission point costs.

We therefore propose that a change is made so that both existing and new transmission connection charges are treated as pass-through, and the term New Transmission Connection Point Charges (NTCC) is removed from the category of Load Related Expenditure. This is consistent with our more detailed proposal on LRE uncertainty mechanisms which can be found in Appendix A.

5.9 High Value Projects (HVP)

We see that a HVP mechanism is useful and complementary to other UMs (e.g. Load related re-opener) and therefore propose that the current RIIO-ED1 High Value Projects (HVP) re-opener is retained for RIIO-ED2. Further, it is important to note that HVPs are not limited to a load driver and can apply to all types of expenditure.

For RIIO-ED1 the definition is:
"costs incurred, or expected to be incurred, by the licensee on any investment project with respect to its Distribution System that is reasonably forecast to cost the licensee £25 million or more (in 2012/13

prices) during the Price Control Period, and for which clear outputs, a needs case and a statement of costs have been provided to the Authority."

We propose one change to the existing definition, being a reduction in the materiality threshold. We have learnt though the RIIO-ED1 price control that £25m (12/13 prices) is a value that is rarely met by Distribution projects. We propose that this threshold is reduced to £18m (20/21 prices). This value more realistically reflects what we would consider a high value project to be in distribution and will ensure large projects receive the appropriate level of scrutiny, whilst not being so low that it becomes an excessive burden to both DNOs and Ofgem.

HVPs can be specified within DNO Business Plans and agreed within Ofgem Draft and Final Determinations, and therefore included as ex-ante allowances. Alternatively, they may be proposed as a new inclusion during a re-opener window under the uncertainty mechanism. All HVPs are assessed as part of closeout to ensure that the outputs have been delivered and any adjustments for non-delivery are made. We propose that all these attributes continue.

We are supportive of the HVP mechanism continuing into RIIO-ED2, though we propose that two windows apply in RIIO-ED2 reflecting the increased uncertainty in the period. We have one HVP in our baseline plan[24] and our strategic planning work indicates that there may be one further project which may come forward in period[25]. We expect that clarity on this will emerge in period and it is likely that we would use the HVP re-opener if it is deemed a qualifying scheme. It is worth noting that some HVPs have a dependency on work undertaken by the TO on its network. The need to co-ordinate with them for shared sites is therefore important and impacting on the timing of a DNO related HVP.

A good example of a potential future HVP might include new Net Zero linear infrastructure (i.e. lines or cables) that require sensitive development involving substantial engagement with the planning regime. Where this is the case, we could potentially see any such project coming forward as a future HVP. We are actively engaging via the Energy Networks Association (ENA) with policy makers and stakeholders on achieving the right balance between the planning and consenting regime and the range of considerations within this.

HVPs could take many different forms, and the mechanism of HVP is therefore a key one not to restrict the nature of the High Value Projects put forward, aside from the value threshold being set appropriately.

Area	Our proposal
Mechanism type	Re-opener
Covering	Adjustments to existing HVP set in ex-ante allowances, and New HVPs that emerge in period
Trigger	DNO
Timing	January 2025 and 2027
Materiality threshold	£18m
Assessment	Via annual reporting and closeout

[redacted]

5.10 Cyber resilience

We are supportive of the cyber resilience OT and IT re-opener provisions as set out in the RIIO-ED2 SSMD (annex 1, Chapter 8) and the RIIO-2 Re-opener Guidance and Requirements.

We agree with Ofgem's view that only a single window is needed (as opposed to the two windows for Gas and Transmission companies) and we consider that a year 3 window would be appropriate. We note that Ofgem is currently undecided whether the re-opener should be Authority-triggered, though this risks additional regulatory burden for Ofgem. The re-opener needs to be company-triggered in any case and it would be sufficient for it to be company-triggered only.

5.11 Return Adjustment Mechanism (RAM)

5.11.1 Introduction

The stated rationale for the introduction of RAMs is to provide protection for consumers and investors if company returns prove to be higher or lower than anticipated by the price control settlement. We do not consider, however, that it is necessary in light of the existing set of tools already available to protect consumers and investors, nor do we think it is desirable in the context of the outlook for RIIO-ED2 and beyond.

RIIO-ED2 represents a challenging period of fast paced change and uncertainty of requirement, in particular given the transition to Net Zero, that must be achieved in the context of a tightened set of financing allowances.

The RIIO-ED2 price control framework already includes various mechanisms to manage and account for levels of out- and under-performance in specific areas of the price control allowance. Alongside the expectation that Ofgem will set an appropriately stringent, balanced and robust price control at the outset, these mechanisms already offer sufficient protection to consumers. The inclusion of an additional overlapping and untargeted measure based on arbitrary parameters does not add any further value in that regard, instead introducing greater risks of distortions to incentives.

The focus of Ofgem's rationale for RAMs appears to be two-fold: first, as a failsafe to cap any perceived excess returns generated by strongly performing networks; and secondly, to protect the cash flows and financeability of underperforming networks. However, the proposed method for calculating any adjustment is flawed as it fails to take account of all relevant inputs.

The level of equity returns earned by the companies in the RIIO-ED2 period and whether or not they should properly be characterised as 'excess' returns deserving of an adjustment can be materially impacted by under- and over-funding with respect to financing and tax. These factors are not considered in the RAMs proposals which carry out the relevant calculations before financing and tax costs are taken into account. However, the return on regulated equity (RORE) can be materially different depending on whether it is assessed pre- or post-financing and tax costs being accounted for.

By excluding them, the extent to which the assessment is indicative of the legitimacy of actual equity returns, which appears to be the policy target for RAMs, is fundamentally compromised. The selection of measures against which to judge whether a RAMs adjustment is required is, therefore, both arbitrary and irrational and may result in discriminatory outcomes.

The impact of RAMs on the incentives contained within the price control framework has also not been given sufficient consideration, particularly if it is not being applied to actual returns. The incentives mechanisms within the RIIO regulatory regime have been one of the cornerstones of driving benefits for consumers through improved performance, efficiency and innovation. This includes, for example, improving customer service as well as shortening and avoiding power cuts. The inclusion of RAMs, however, especially as it is currently designed, will distort the incentives to make these investment decisions which benefit consumers and fully explore delivering any potentially available efficiencies.

For instance, if a licensee knows that it is certain to be overfunded on financing and tax, it may not have the same incentive or management drive to outperform on ODIs as to do so would create the risk of a RAMs downward adjustment on the company's returns. Ultimately, this would be to the detriment of consumers. Equally, if a licensee delivers operational outperformance, benefitting consumers directly through improved reliability and cost sharing, but then overall loses around half of this as a result of financing and tax underfunding, the RAMs assessment will take no account of this and the licensee will not be able to achieve the level of returns that the RAMs calculation has assumed. This is inconsistent with the second rationale for the introduction of RAMs, namely as a protection measure for investors.

Ofgem has also failed to demonstrate how the design of RAMs would provide protection in the event of returns being lower than expected. The assumption is that a positive RAMs adjustment in such a scenario would assist licensees with respect to their credit metrics and financeability. However, Ofgem's approach fails to take account of the fact that the rating agencies assess credit metrics on the post-finance and tax position of the licensee.

Ofgem has not provided sufficient evidence to justify the introduction of the RAMs as an additional measure to protect consumers, or to demonstrate that it will not have unintended and negative consequences for consumers. Therefore, we propose ultimately that a RAM should not apply for RIIO-ED2.

5.11.2 Our proposal

To the extent that Ofgem can demonstrate that RAMs are necessary, it is, at present, of flawed design to meet the concerns it is intended to address and may, instead, result in unintended and undesirable outcomes inconsistent with delivering for customers. As such, if it is utilised for RIIO-ED2 then, at the very least, some important changes to the mechanism are required.

It is essential for the technical integrity of the mechanism that the RAMs calculation takes proper account of all relevant inputs, including financing and tax under or over funding. It should take account of all net returns to equity and not just some.

Ofgem also needs to give greater consideration to setting an appropriate floor level for RAMs. It should ensure that it is triggered at a level, and in a manner, that limits distress of the affected networks in a way that is proportional to those networks impacted at the RAMs ceiling. This will be an important factor both in assessing downside financeability and in discussions with ratings agencies.

Additionally, our view is that setting a single RAMs threshold cap at 300bps is too restrictive. It would undermine the legitimate strength of incentives when these are considered as a collective package, potentially curbing a company's ambition to drive outcomes for consumers. Ofgem needs to provide confidence to stakeholders that if companies are successful in delivering what customers value across several incentives then the incentives will work as designed.

A single threshold level up and down may have the benefit of simplicity, but we do not necessarily support a symmetrical threshold either side of the baseline allowed return on equity. Any RAM should be structured so that does not disincentivise networks from continuing to strive for innovation and further efficiency. The threshold level should be set in this context.

5.11.3 Stakeholder engagement

We have conducted some stakeholder engagement with the consumer statutory representative Citizens Advice. In their report on draft ED2 business plans they notes that "*Citizens Advice has previously suggested that out and under performance related to the cost of debt [financing] should be included within the Returns Adjustment Mechanism (RAM), alongside performance against other cost allowances.*"[26] Our discussion with Citizens Advice indicates to us that they appreciate some of the risks under RAMs that we are highlighting.

We remain committed to seeking to work with Ofgem and other stakeholders on RAMs and if and how this should apply for RIIO-ED2.

6. Our comments on all other Ofgem proposed uncertainty mechanisms

Table 6.1: Other Ofgem planned uncertainty mechanisms for RIIO-ED2

Area	Type of mechanism	Existing or new for ED2 (as proposed by Ofgem)	Section and comment
Inflation indexation of RAV and allowed return	Indexation	Existing – Revised for ED2	Section 6.1
Cost of debt indexation	Indexation	Existing – Revised for ED2	Section 6.2
Cost of equity indexation	Indexation	New	Section 6.3
Real Price Effects	Indexation	Existing – Revised for ED2	Section 6.4
Tax review	Re-opener	New	Section 6.5
Pensions adjustment	Pass-through	Existing – Revised for ED2	Section 6.6
Enhanced Physical Site security	Baseline allowance and/or re-opener	Existing	Section 6.7
Coordinated Adjustment Mechanism (CAM)	Re-opener	New	Section 6.8
Rail Electrification	Re-opener	Existing – Revised for ED2	Section 6.9

6.1 Inflation indexation of RAV and allowed return

No change proposed to ED2 proposal by Ofgem, for full details of our final business plan financing proposals see Finance Annex 28.

6.2 Cost of debt indexation

For full details of our final business plan financing proposals see Finance Annex 28.

6.3 Cost of equity indexation

For full details of our final business plan financing proposals see Finance Annex 28.

[26] Citizens Advice views on the electricity distribution network companies' draft business plans for RIIO-ED2 - Citizens Advice

6.4 Real Price Effects (RPEs)

No change proposed to RIIO-ED2 proposal by Ofgem. For full details on our assessment of RPEs in RIIO-ED2 and the appropriate inflationary metrics, please see our Cost and Benchmarking Annex 20 Appendix E as developed by NERA through the ENA.

6.5 Tax review

No change proposed to ED2 proposal by Ofgem. For full details of our final business plan financing proposals see Finance Annex 28.

6.6 Pensions adjustment

No change proposed to ED2 proposal by Ofgem. For full details of our final business plan financing proposals see Finance Annex 28.

6.7 Enhanced physical site security

We have proposed no change to the provisions set out by Ofgem in the RIIO-ED2 SSMD. We agree that the treatment as ex-ante baseline allowances with a re-opener (including a zero-materiality threshold) as per RIIO-ED1 is the right treatment for RIIO-ED2.

6.8 Coordinated Adjustment Mechanism (CAM)

The CAM was introduced into the RIIO-ED1 licence at the same time as it was developed for the RIIO-2 companies. We do not propose any changes to the current mechanism as it is designed.

6.9 Rail electrification

Ofgem proposes to retain the RIIO-ED1 re-opener for rail electrification, expanding it to include both costs associated with Network Rail electrification projects and costs associated with projects from companies that may not have a connection with Network Rail.

We agree with the continuation and expansion of this mechanism as proposed.

6.10 Miscellaneous pass-through costs

There are a range of costs which are deemed to be wholly outside of the DNO control, which are treated as pass-through within the regulatory framework.

A summary is shown in table 6.2 below, and each individual component is referenced below along with an explanation of where we agree with Ofgem proposals for RIIO-ED2 and where we propose changes are implemented.

Table 6.2: Miscellaneous pass-through costs items for RIIO-ED2

Miscellaneous Pass-through	Our change or new proposal
Ofgem licence fee	No change proposed to RIIO-ED2 proposal
Business rates	No change proposed to RIIO-ED2 proposal
Transmission Connection Point Charges	Extend to include all transmission connection point charges, whether existing or new (see section 5.8)
Smart Meter Communication Licensee Charges	Extend to include all code fees (see section 6.10.4)
Smart Meter Information Technology Costs	No change proposed to RIIO-ED2 proposal
Ring Fence Costs	No change proposed to RIIO-ED2 proposal
Supplier of Last Resort Costs	No change proposed to RIIO-ED2 proposal
Eligible Bad Debt Costs	No change proposed to RIIO-ED2 proposal
COVID Bad Debt Costs	No change proposed to RIIO-ED2 proposal

6.10.1 Ofgem licence fee

There are no changes proposed to the RIIO-ED2 proposal as set out by Ofgem. We agree that the treatment as pass-through cost as per RIIO-ED1 remains appropriate for RIIO-ED2.

6.10.2 Business rates

We are proposing no changes to the RIIO-ED2 proposal as set out by Ofgem. We agree that the treatment as pass-through cost as per RIIO-ED1 remains appropriate for RIIO-ED2.

6.10.3 Transmission Connection Point Charges (TCP)

We have proposed a change to the definition of TCP for pass-through as explained in section 5.8.

6.10.4 Smart meter communication licensee charges

DNOs are mandated to be signatories of the Smart Energy Code (SEC) and a user of the Data Communications Company's (DCC) smart metering network in line with our licence. Being a DCC network user incurs a monthly charge which is treated as pass-through under this mechanism in RIIO-ED1.

We agree with Ofgem's proposal to continue this pass-through treatment for RIIO-ED2.

Under the licence granted by Ofgem, DNOs are also mandated to be signatories of other industry codes, all of which incur a charge. We propose that all of these mandatory costs should have the same pass through treatment to the costs that arise from the DCC.

We recognise that Ofgem and BEIS are currently undertaking a Significant Code Review on Energy Codes Reform. The shape and structure of future codes are yet to be determined by Ofgem and BEIS, providing more uncertainty over required future expenditure and making forecasting of costs more difficult for DNOs than in the past. Ofgem currently says that "*We propose that code managers should be funded through charges levied on code parties in accordance with a charging methodology set out in the relevant code(s). Code parties would pay a portion of these charges (calculated in accordance with the charging methodology) and, provided appropriate processes and safeguards were in place,* *code managers could be allowed to charge code and non-code parties for some value added or optional services.*"

Our forecast expenditure is shown in C12, however for reasons stated above, these costs are uncertain due to changes as a result of the Energy Codes Reform. We consider that all costs resulting from DNOs being signatories of mandated codes should be treated as pass-through in the same way that the DCC costs are currently treated.

6.10.5 Smart meter information technology costs

No change proposed to RIIO-ED2 proposal as set out by Ofgem. We agree that the treatment as pass-through cost as per RIIO-ED1 remains appropriate for RIIO-ED2.

6.10.6 Ring fence costs

No change proposed to RIIO-ED2 proposal as set out by Ofgem. We agree that the treatment as pass-through cost as per RIIO-ED1 remains appropriate for RIIO-ED2.

6.10.7 Supplier of Last Resort (SoLR) costs

No change proposed to RIIO-ED2 proposal as set out by Ofgem. We agree that the treatment as pass-through cost as per RIIO-ED1 remains appropriate for RIIO-ED2. However, in the light of live issues with the retail market at the time of writing, changes to the licence and mechanisms for RIIO-ED2 may be required.

6.10.8 Eligible bad debt costs

No change proposed to RIIO-ED2 proposal as set out by Ofgem. We agree that the treatment as pass-through cost as per RIIO-ED1 remains appropriate for RIIO-ED2. However, in the light of live issues at the time of writing with the retail market, changes to the licence and mechanisms for RIIO-ED2 may be required.

6.10.9 COVID-19 bad debt costs

No change proposed to RIIO-ED2 proposal as set out by Ofgem. We agree that the treatment as pass-through cost as per RIIO-ED1 remains appropriate for RIIO-ED2.

Appendix A: Uncertainty Mechanism for Load Related Expenditure

This appendix sets out the uncertainty on load related expenditure in RIIO-ED2 and proposed method of managing this uncertainty via revisions to the existing RIIO-ED1 load related re-opener mechanism.

1 December 2021

Appendix A - Load Related Expenditure

1. Executive Summary

Load Related Expenditure (LRE) is a critical component of our business plan; it facilitates our customers' requirements, enables economic and regional growth and supports the transition to Net Zero.

LRE has a range of drivers and a number of associated uncertainties, all of which must be carefully considered when designing an Uncertainty Mechanism (UM).

Drivers of Uncertainty

- Regulatory change/Access SCR
- Change in government or regional policy
- Pace and pathway of decarbonisation
- Nature/location and volume of connections
- Economic change
- Other exogenous factors (e.g. technology changes)

Drivers of Reinforcement

- Demand and generation
- Thermal capacity
- Voltage
- Fault level
- Power quality
- Unlooping
- Service related constraints

The approaches for enabling LRE in the DPCR5 and RIIO-ED1 price controls have served customers well for many years. Our proposal is to take the existing elements of the RIIO-ED1 mechanisms, with a limited number of revisions to ensure that they continue to be fit for purpose for the challenges we will face in RIIO-ED2.

High Value Projects

- To deal with large projects, £18m + allowing an appropriate level of project level scrutiny
- Protects customers from risk of non-delivery
- Provides the DNO with the ability to revise allowances, or bring forward new projects

Load Related Re-opener

- Protects customers from forecasting risk
- Flexible enough to deal with changes driven by Access SCR outcomes
- Can cover all reinforcement drivers, all voltages and all solutions including flexibility services and energy efficiency
- Encourages innovation
- Enables DNO to flex allowances to meet changing needs

LCT LV service solutions Volume Driver

- Removes a key barrier to LCT adoption
- Deals with volume uncertainty
- Keeps bills as low as possible, only increasing as requirements increase
- Enables automatic adjustments to revenues

Our proposal takes a holistic look at all the components of LRE and delivers Ofgem's aim of simplification in the price control where possible. This comprises three key mechanisms, each dealing with uncertainty in a slightly different manner. These three combined are complementary and provide a whole solution to the range of load related expenditure that may be incurred.

This Appendix looks at Load Related Re-opener (LRR) whilst Appendix B deals with the LCT LV service solutions volume driver and section 5 of our main Managing Uncertainty Annex covers High Value Projects in more detail.

2. Introduction

2.1 Introduction

Each regulatory period brings differing uncertainties, however, in the case of Load Related Expenditure (LRE) this has been, and will continued to be, an enduring uncertainty. Whilst the specific drivers of uncertainty and investment need may change from one period to the next, general uncertainty around LRE needs will always remain. In DPCR5, the Load Related Re-opener (LRR) was introduced to account for uncertainties associated with demand, connections and general reinforcement requirements and allowed revenue adjustments to be made to reflect changing requirements. In RIIO-ED1, this mechanism was developed further and by the end of RIIO-ED1 the LRR will have been in place for 13 years.

In RIIO-ED2, the level of uncertainty will be even higher than we have seen in previous periods. In 2019, the UK Government passed legislation enshrining into law the target of Net Zero greenhouse gas emissions by 2050, making the UK the first major economy to set a binding target in law. This was followed by the Committee on Climate Change Sixth Carbon Budget (December 2020) in which they recommended that 60% of the necessary emissions reduction needs to be achieved by 2035. The Government's 10 Point Plan, Energy White Paper and Transport Decarbonisation Strategy all point to the need to support the continued decarbonisation of power, electrification of transport and move to low carbon heat sources. It is widely accepted that a combination of these transformational changes will result in a doubling of electricity demand by 2030.

Whilst the overall direction towards Net Zero is known, the actual pathway and pace of change as a result of technological advances and changes in consumer behaviour are less clear. Government policy and regulatory developments are critical components that could influence both pace or pathway.

What is clear is that electricity distribution networks must be ready to adapt to these future pathways so as not to be a barrier whilst ensuring that appropriate protections are in place for consumers.

2.2 What networks need to deliver

We recognise the role we need to play in supporting and enabling our region and the wider economy to meet the challenging Net Zero targets. We will demonstrate leadership by setting decarbonisation targets for our own operations, as well as offering support to customers, businesses and stakeholders as they set and pursue their own targets and lifestyle changes.

Delivering Net Zero has already started to change how we plan, develop and operate our assets. This will continue to evolve as we further embrace the use of energy efficiency and flexibility services as they become available, continue to maximise the use of smart technologies and harness the power of data. Net Zero will also require investment in new infrastructure as we work to meet the demand that will come through the transition to electric vehicles in particular.

Ofgem has been clear to us that there are two major tests of success in the RIIO-ED2 regulatory framework, that customers must be able to connect their low carbon technologies (LCT) to the network at the location and time that they want and that DNOs need to facilitate the connection of renewable generation to the distribution network to support the transition to clean energy.

We can help to achieve this by working our system harder and smarter by reviewing our planning policies; maximising utilisation of our existing assets; encouraging and promoting the flexibility services market including energy efficiency; deploying innovation and where necessary installing bigger assets.

The sheer scale of change that the UK is embarking on as we transition to a low carbon economy will inevitably increase the level of investment that companies need to make in their distribution networks.

We must ensure that network constraints do not prevent the adoption of low carbon technologies and that capacity is available as it is required whilst ensuring that our investment plans are delivered at the lowest cost to customers.

2.3 Access SCR

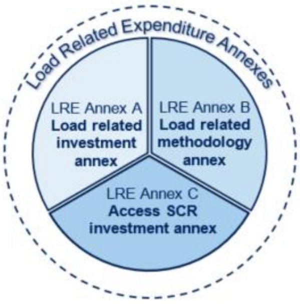
In December 2018 Ofgem launched a significant code review of Access arrangements and Forward-Looking Charges (Access SCR). In June 2021, Ofgem published its minded-to positions on distribution network connection charges, improved definition and choice of access rights and ongoing transmission network charges. Whilst these minded-to positions give us a direction of travel upon which to base our assumptions within our final business plan, a significant number of uncertainties around the detail and subsequent customer response remain, which will inevitably have an impact on the scale of LRE that is required in period.

We understand that work on the DUoS (Distribution Use of System charges) has been paused to ensure this is aligned with the Full Chain Flexibility programme of work underway within Ofgem, however this separation of the elements of the Access SCR does add a further layer of uncertainty which may affect LRE during RIIO-ED2.

2.4 Navigating this document

This appendix to our Managing Uncertainty Annex provides details on our approach and proposal for managing the uncertainty for load related expenditure. Further detail on our load plan itself, methodology and impacts of Access SCR details can be found in our suite of LRE Annex 3 as shown in figure 2.1.

Figure 2.1: LRE Annexes



Section 3 provides insights into our experience in RIIO-ED1, whilst Section 4 introduces the key figures in our load plan and the uncertainties we face.

Section 5 provides insight into the stakeholder views we have received, and Section 6 explores the balance between ex ante allowances and the use of uncertainty mechanisms.

Section 7 provides the details of our proposal with Section 8 considering alternative options.

Section 9 looks at the relationship between the various UMs and how to ensure separability, whilst Section 10 shows the cost treatment of this expenditure within the Business Plan Data Templates (BPDTs) and Section 11 provides our conclusion.

3. Experience in RIIO-ED1

3.1 Forecasting variance

As with RIIO-ED2, one of the major uncertainties in RIIO-ED1 was around the uptake of LCTs. In 2013, for our RIIO-ED1 business plan, Ofgem required us to select a DECC scenario upon which our plan was based. We selected the lowest of the DECC scenarios however actual LCT update in our region has been lower still. Conversely, during RIIO-ED1 Distributed Generation (DG) connections have considerably exceeded the RIIO-ED1 forecast. It is worth noting that based on the existing RIIO-ED1 charging structure, this additional capacity requirement has resulted in comparatively minor LRE expenditure, however based on the minded-to positions for the Access SCR, this would have had a different outcome for LRE requirements.

Whilst in RIIO-ED1 Ofgem required DNOs to select one of the DECC scenarios as their basis for business planning, in RIIO-ED2 Ofgem has provided DNOs with the ability to put forward their own forecasts based on certain criteria which allows for greater regional inputs.

3.2 RIIO-ED1 process

In RIIO-ED1, there are two windows for DNOs to trigger the LRR; 2017 and 2020, with Ofgem having the option to trigger at the end of the period in 2023 making a total of three points of adjustment over the eight years. In 2017 and 2020 no DNOs triggered the mechanism, although it may be used by Ofgem at the end of the period.

Due to the nature of current regulatory reporting, particularly the treatment of innovation offset, it is unclear whether any other DNOs will be outside of the dead-band as currently set. However, based on enduring value adjustments reported, we expect that at least one licensee will be subject to the LRR at the end of RIIO-ED1, with an anticipated return to customers where allowances are under-spent.

All DNOs will be subject to a closeout assessment at the end of the period which will determine whether Ofgem will trigger the LRR for each licensee.

One of the lessons we have learned is that the dead-band, (the +/- % variance upon which no adjustments to allowances are made) is potentially too high in RIIO-ED1 and this should be addressed for any mechanism taken into RIIO-ED2. We cover this in greater detail in section 7.3.5.

The closeout treatment for RIIO-ED1 was consulted and decided on in 2019 which was preferable to DPCR5 where closeout treatment was agreed at the time of undertaking the assessment at the end of the period. We recommend based on our experience that the detailed definition of closeout treatment is set out before the price control commences. This is key and avoids any ambiguity in period which may result in unintended consequences as a result of DNOs having a lack of regulatory clarity. Given the work undertaken to establish closeout treatment for RIIO-ED1, we consider that this could be achieved relatively easily for RIIO-ED2 and suggest that this is done ahead of the start of RIIO-ED2 taking the RIIO-ED1 approach as the starting point.

It is important that any closeout review does not become a hindsight review of decisions and that it looks through the lens of the information that the company had at the time of making the decision.

4. Load Related Investment Plan and Uncertainty

4.1 Our load related investment plan

Our load related investment plan has been built in accordance with the methodology detailed in LRE Annex 3B.

The value of our “best view” baseline (ex-ante) load investment plan is £141.4 million as shown in figure 4.1. An additional £20.6 million for LV monitoring closely associated with load related expenditure is reported with Op IT and Telecoms costs however (whilst reported separately) we consider this to be LRE, for the purposes of an uncertainty mechanism.

In line with Ofgem guidance, Access SCR impacts are detailed in part 3C of our load annex suite and are fully excluded from our baseline (ex-ante) load investment plan.

We propose that the investment shown in figure 4.1 is funded ex-ante, meaning that allowances are set in advance of the period and flow through revenue each year in accordance with a pre-defined value and process.

Figure 4.1: Baseline (ex-ante) load related investment plan

Load related investment area	Baseline (ex-ante) value £m
Primary (132kV and 33kV)	£28.0
Secondary (11kV, 6.6kV and LV)	£61.1
Fault level reinforcement	£32.2
NTCC	£0
Unlooping	£20.1
LV monitoring	£20.6
Total	£162m **£141.4m (excluding LV monitoring)**

By adopting our unique ATLAS forecasting methodology, along with assessment and optioneering approaches following our normal network planning processes, we have ensured that our plan is considerate of downward cost drivers such as capitalising on existing network capacity, energy efficiencies, use of flexibility services and network visibility.

Our load related investment plan is our best view of what we expect will be required during the RIIO-ED2 period, built up from low regret actions responding to the network needs aligned with our high certainty Central Outlook scenario.

4.2 Load related uncertainty

As described in section 2, there are a range of drivers for uncertainty in RIIO-ED2 linked to decarbonisation and Net Zero aims. This is not an exhaustive list:

- the volume, pace and location of Electric Vehicles (EVs) and Heat Pumps (HP) uptake,
- the type, location and volume of connections for both demand and generation
- regeneration plans, spatial framework and growth plans
- changes in local and national decarbonisation targets and plans
- changes in the type, volume and location of connections driven by a change in customer behaviour due to the Access SCR
- changes to Government policy or regulatory approach
- other exogenous factors such as the global pandemic in recent years or the 2008 financial crisis

It is also unclear how the market for flexible services will evolve over the coming years. Whilst it is expected that the market will grow and that we will be able to procure flexibility as an alternative to traditional network investment, this relies on the ability of flexibility providers to grow their offerings, understand DSO requirements, and be in the right location to provide such services. If flexibility cannot be procured more cost effectively, meaning that a network-based solution is required because this is a lower whole life cost, this could increase our required load expenditure. Equally if we are able to contract more than anticipated at economical prices, our expenditure for network capacity solutions could reduce.

Some of these above uncertainties can be modelled and our plans consider differing volumes of EVs and HPs and the corresponding potential change in LRE required. We have also considered the potential impacts of the outcome of the Access SCR.

Any scenario that is assumed for business planning in 2021 will inevitably differ from actual demand on the network, and for this reason, we, Ofgem and our stakeholders consider it is not appropriate to rely solely on baseline allowances to provide funding for the potential investment required. Using ex-ante allowances alone will result in having investment values which are either too high or too low, neither of which are in customers' interests.

To ensure that DNOs are able to adapt to changes during RIIO-ED2 and deliver the load related investments required to allow our customers to decarbonise their lifestyles, it is agreed that an agile uncertainty mechanism is required.

The type of uncertainty mechanism is yet to be decided, however in RIIO-ED2 Sector Specific Methodology Decision published in December 2020[27] Ofgem considers the development of an uncertainty mechanism that automatically adjusts revenues in line with expenditure incurred, thereby reducing the delay associated with in-period, administrative decision making on adjustments to revenue. It was clear that no decision would be made at this stage, and it would depend on whether such a mechanism can be designed in a way that does not expose customers to a disproportionate risk of higher costs.

We have not yet seen any detailed proposals set out by Ofgem on how such an automatic mechanism could work in practice, and Ofgem working groups have not developed this any further than an initial concept stage. Work took place, particularly in late 2019 and early 2020, on mechanism considerations and options. This work was done between DNOs and interested stakeholders in an earlier phase of preparatory work on RIIO-ED2.

Whilst developing our draft and final business plans we have given considerable thought to the most appropriate mechanism that can adjust revenues in line with required LRE, whilst providing adequate protection for customers and enabling companies to meet Net Zero needs. We have concluded that an evolution of the existing RIIO-ED1 LRR is the best option. We have identified that Ofgem's desire for a mechanistic approach for other elements can be met and we propose a mechanism for LCT LV service solutions which is shared in Appendix B.

4.3 What is the issue

As explained earlier there are a range of uncertainties which could either reduce or increase the amount of load related expenditure that is required in the RIIO-ED2 period. The pace and pathway

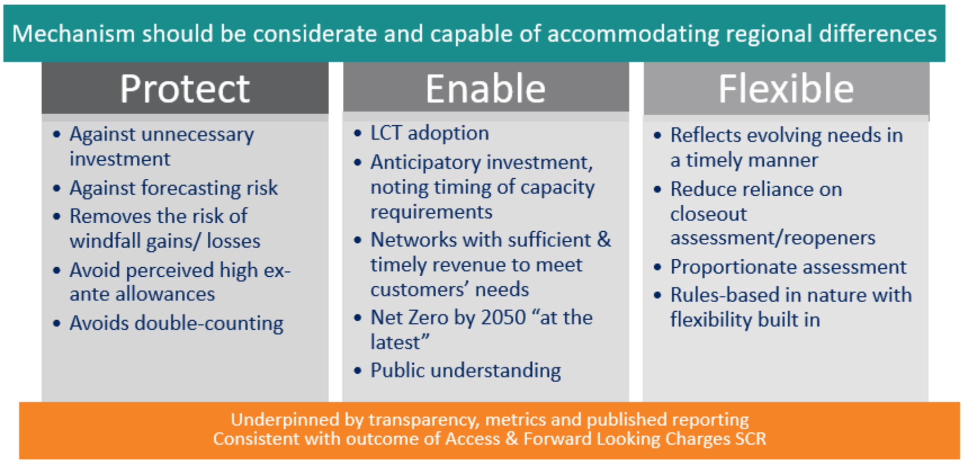
[27] https://www.ofgem.gov.uk/publications/riio-ed2-sector-specific-methodology-decision. Overview, Para 1.11

towards Net Zero is the biggest known uncertainty in our plan, influenced by the unknown impact of Access SCR decisions.

The challenge for companies and Ofgem is how to set price controls which provide networks with sufficient timely funding and flexibility to facilitate the move to a low carbon economy, provide capacity required and manage network constraints, without risking ex-ante allowances being set at levels which may increase charges to customers unnecessarily.

4.4 Principles for a LRE Uncertainty Mechanism

In early 2020, we hosted a workshop inviting all DNOs, ENA and Ofgem to discuss the treatment of LRE in RIIO-ED2. Attendees at that meeting agreed a set of principles that should be used when developing a mechanism for LRE.



These principles, developed between the various stakeholders mentioned have helped guide us when assessing options.

5. Stakeholder engagement

The whole of the North West is seeking to decarbonise at a faster rate than the national 2050 target. Greater Manchester Combined Authority (GMCA) has set a decarbonisation ambition for 2038, Cumbria for 2037 and Lancashire are developing a more detailed plan working from a high-level aspiration of 2030. Key stakeholders and businesses in the region are setting aggressive targets for decarbonisation such as the Environment Agency in the public sector as well as large companies within the private sector.

During the development of our DFES, engagement with Local Authorities has indicated greater aspiration and ambition aligned to their earlier target dates, than is currently supported by some of our core assumptions coming from national data models for EV and heat pump roll out.

Engagement with our independent Sustainability Panel challenged our ambition to support the decarbonisation aims of the region. This was also discussed with the Customer Engagement Group (CEG) and resulted in us developing the proposal to ensure that we provide the capacity required to meet these stakeholders' ambitions as they emerge. We expressed this as:

Ensuring capacity is provided in the right place and at the right time as electricity demands increase

This proposal was tested and refined through all the phases of stakeholder engagement programme and resulted in a high customer and stakeholder acceptability score of 82%.

The proposal requires us to ensure that our capacity provision matches regional progress towards these targets and therefore requires the ability to flex in line with requirements.

In bi-lateral discussions with key stakeholders, such as Greater Manchester Mayor Andy Burnham, the key expectation is that we will keep up with the pace of development and not become a blocker on regional ambition, nor impede customers meeting their needs. Stakeholders tell us that the RIIO-ED2 framework must be able to facilitate strategic investment to support Net Zero, and that it needs to be flexible enough to adapt to changes in period. This is necessary to prevent a delay in investment or networks becoming a blocker to the uptake of EVs in particular.

In November 2020 we hosted our Powering up the North Summit, which provided a forum to bring together senior political and business leaders and stakeholders across the region to debate some of the key issues facing the energy sector. Following this summit three additional events were organised to look at the distinct issues and challenges that each sub-region (Cumbria, Lancashire and Greater Manchester) faces and bring together business and political leaders from those specific regions.
During the summit we asked the question: *What are the key environmental and economic challenges faced on the road to Net Zero?*

Stakeholders' perceptions regarding the key challenges faced by decarbonising at pace were compared across the three regions and are summarised in the table below. A great deal of commonality was observed in the feedback with community engagement, workforce availability and a supportive policy environment perceived to be key challenges across our area. There were also some localised nuances with improving air quality and alleviating fuel poverty referenced in Greater Manchester and expansion of electric vehicle infrastructure given extra emphasis in Cumbria. Many of these challenges in one way or another may influence, or be affected by, our LRE plans.

In response to this feedback we showed in our draft RIIO-ED2 Business Plan consultation the difference between our base plan assumptions for load related expenditure indicated by our DFES together with accelerated decarbonisation versions of the Central Outlook, Consumer Transformation and Leading the Way. The main difference between these accelerated versions and the original DFES scenario is that transport and heating is fully electrified before 2040 for a large part of our license area. These accelerated decarbonisation scenarios which show stakeholders the potential effects and the required response have been welcomed by stakeholders in bi-lateral discussions.

To support the need to adapt to these accelerated scenarios we highlighted in our Draft RIIO-ED2 Business Plan consultation the need for a mechanism to deal with uncertainty regarding the speed of the transition to Net Zero.

In the December 2020 SSMD[28] Ofgem noted that there was a range of views on uncertainty mechanisms, however there were general views that uncertainty mechanism should work quickly and avoid delaying investment.

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[28] https://www.ofgem.gov.uk/publications/riio-ed2-sector-specific-methodology-decision. Overview Document Para 4.26

In September 2021 we held a second Powering up the North event where Martin Cave, Chair of the Gas and Electricity Markets Authority, stated *"It seems to us that the North West is well-placed to lead the fight against climate change, with bold and ambitious targets to achieve net zero across the region. When society moves to clean up heating, transport and power, it will do so at a local level. In fact, it's difficult to overstate the role of local in driving forward this change.*"

At the same event, Paul van Heyningen, Deputy Director of Net Zero Electricity Networks at the Department for Business, Energy and Industrial Strategy said: "*I echo the points that Martin Cave and others have made about the importance of locally-led development and local action in terms of meeting our net zero commitments." He went on to say "The sixth Carbon budget published in 2021 requires us to reduce total emissions by 78% by 2035 which when you think about what that means for our electricity system, it basically means full decarbonisation, pretty much, of our electricity system by 2035. We're talking about unprecedented pace and scale*"

Also, at the event, we heard a direct call for a Load Related Expenditure Uncertainty Mechanism by Henri Murison, Director of the Northern Powerhouse Partnerships, who has recognised the need for the RIIO-ED2 regulatory framework to address the known uncertainty.

We have now developed more detail of how this uncertainty mechanism should work and the potential interactions between the annual DFES reforecasting process, uncertainty mechanism mechanics, financeability and our delivery strategy. Section 7 of this document provides details of our proposal for how an adaptation of the existing Ofgem mechanism for RIIO-ED1 can deliver for companies and customers in RIIO-ED2.

6. Balance between ex-ante allowances and uncertainty mechanism

With every price control there should always be a tension between expenditure and affordability at the forefront of companies, regulators and stakeholders' minds. Uncertainty mechanisms are designed to ensure that companies are not unnecessarily exposed to risks outside of their control, whilst protecting customers against material forecasting risks at the time of setting the price control. In order to strike the right balance between delivering the investment that is required to meet Net Zero, at the lowest cost to customers, we must consider what is an appropriate value for ex-ante funding and what should be covered by the use of uncertainty mechanisms.

On this point, we have been guided by the Ofgem letter to all DNO CEOs of 8 October 2021 which tells us:
"…. For the benefit of comparability we want you to present your requirement for ex ante allowances in your Final Business Plan on the expenditure in which you have confidence in being required under all forecast pathways. You should do so working with an assumption that sufficiently flexible and agile uncertainty mechanisms will be available to enable your expenditure to flex in line with whatever demand materialises. Where appropriate, this ex ante proposal should include strategic investment that is essential in order to ensure that you are capable of meeting potential demand growth in future price control periods. Where this is the case, this type of expenditure needs to be clearly identified and justified…."

There are risks associated with both under-funding and over-funding in ex ante allowances.
Under-funding could lead to delays to Net Zero enablement, customers being unable to connect to the network in the location they require or use their connection in the way they wish, or DNOs' inability to mobilise to meet requirements with a knock-on effect on deliverability in future periods.

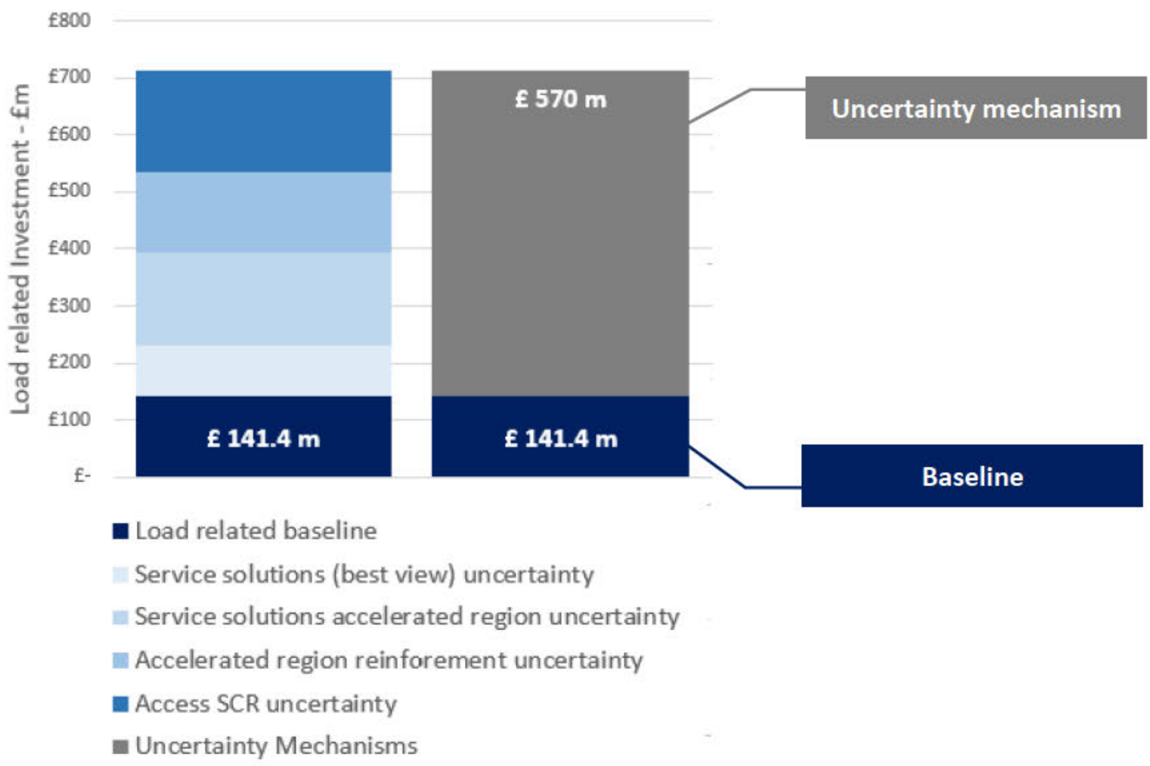
Even with less limited funding there remains an upper bound as to what is deliverable, in terms of planning, land access, design, skills and people, as well as the disruption that widespread investment could bring to local communities and street works.
Over-funding puts a strain on affordability by increasing customer bills unnecessarily and potentially has a higher risk of asset stranding as there could be a perception that a DNO may invest with lower certainty, meaning assets may not be needed when installed.

We also know that factors will come into play that will vary actual requirements compared to that which is forecast. These will be driven by both national and local government actions as well as customer and connectee behaviour.

Providing DNOs with adequate ex-ante allowances, combined with a well-designed uncertainty mechanism, will give both companies and stakeholders confidence that the right intervention, at the right place and the right time can be delivered. Companies will be able to gain efficiency through strategic planning, taking an informed and holistic approach to investment decisions, the benefit of deferring some through emerging flexibility services and, where appropriate, taking a whole system approach and linkage to gas and transmission plans and activities.

Our ex-ante LRE forecast includes investment required to deliver the capacity based on our Central Outlook forecast and considerate of the other scenarios to ensure that we do not foreclose future pathways. We have sufficient certainty of this to ask for this value to be granted as ex-ante allowances. Further detail on how this Central Outlook is derived can be found in our LRE annexes.

Figure 6.1: LRE ex-ante proposal[29], together with potential use of UM.



[29] Excluding LV monitoring, including LCT LV services solutions

7. Proposed Uncertainty Mechanism – Load Related Re-opener

7.1 Overview

Element	Our proposal
Name	Load Related Re-opener (LRR)
Need	Any scenario used for network development planning in 2021 will inevitably differ from actual requirements in the period. The pace and pathway for decarbonisation is uncertain and it is critical that networks do not act as a barrier to achieving Net Zero aims, whilst at the same time protecting customers and delivering the most effective transition to Net Zero at lowest cost. An agile uncertainty mechanism is required to adjust revenues in period to reflect actual consumer requirements, ensure delivery is not unnecessarily delayed and ensure fast cashflow to companies/customers as required.
Common or Bespoke	This is a common issue across all DNOs and we propose this solution is applied as common across all licensees.
Purpose	To revise allowed revenue +/- based on costs incurred, or forecast to be incurred, to accommodate changes in levels, nature and pattern of customer requirements.
Consumer case/benefit	Net Zero means customers are adopting new uses for electricity such as for mobility and heat. These are essential services which will be low, or zero carbon once provided by electricity. This mechanism is a key proposal to enable us to deliver what we need to do to enable Net Zero at lowest cost to the consumer.
Type	Re-opener
Threshold	Materiality in line with common features shown in Section 3 of the Managing Uncertainty annex (0.5% of annual base revenues)
Window	Year 3 - May 2025
Treatment of innovation costs	It is important that an incentive on innovation is retained. Innovation has been proven to bring significant consumer benefits and reduce costs both in current and future price controls and this should be encouraged, particularly as we look to transition to a smart and more flexible energy system.
Treatment of costs up to materiality threshold	Subject to Totex incentive rate (TIM)

7.2 RIIO-ED1 mechanism

The existing RIIO-ED1 mechanism was built on the principle defined in DPCR5 with scope of expenditure increased for RIIO- ED1. This reflected the increased uncertainty since DPCR5, partly due to the lack of clarity around how the uptake of LCTs would impact the network.

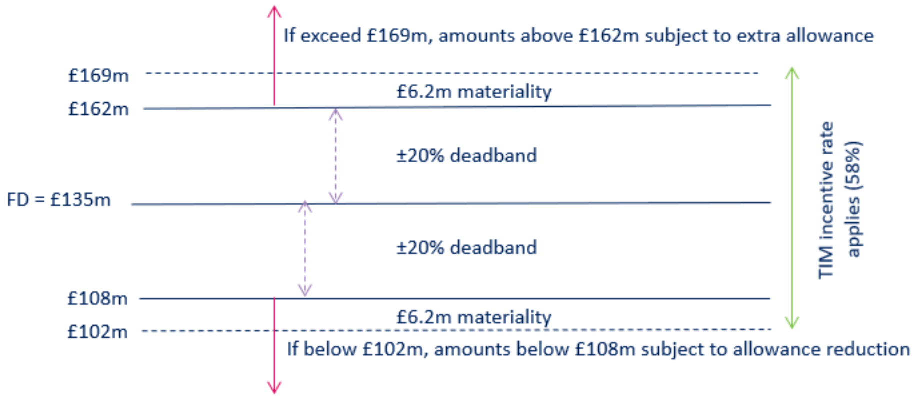
The re-opener allows for adjustment to allowances where actual and forecast expenditure differ materially to those set at the start of the period.

DNOs can submit a request for additional allowances or return some allowances to customers where they demonstrate that their costs are efficient and either exceed or are below the relevant materiality threshold.

The categories of expenditure covered are broadly;
- Primary and secondary network general reinforcement;
- Primary and secondary network new and modified connections;
- Fault level reinforcement; and
- New transmission point connection charges

The re-opener allows for the recovery of efficient costs outside a dead-band, provided that the costs are material. The figure below demonstrates the test for adjustments using ENWL RIIO-ED1 allowance values.

Figure 7.1: RIIO-ED1 thresholds using ENWL opening allowances



Between £102m and £169m no adjustment is made, all under or over-spend is subject to TIM.

RIIO-ED1 is an eight-year price control period, which is unique as each regulatory period before and RIIO-ED2 after will be five years long. In RIIO-ED1, DNOs can trigger the re-opener during two windows, 2017 and 2020, if they can demonstrate that their efficient expenditure over RIIO-ED1 is, or will be, different to allowances by an amount greater than the dead-band plus the materiality threshold.

The re-opener is symmetrical and can also be triggered by Ofgem at the end of the price control if efficient expenditure is materially different from allowances. This is generally called close-out and forms a review of LRE and whether the materiality test has been passed, which would trigger a review and potential adjustment to allowances.

Where the materiality test is not passed, any over or underspend is subject to the Totex Incentive Mechanism (TIM) and is shared by customers and the company based on the applicable percentage[30] via adjustment to future revenues.

In all cases, variations in expenditure up to the dead-band remain subject to the TIM, whether or not the re-opener is triggered.

The RIIO-ED1 mechanism also takes into account efficiencies generated by DNOs through the use of Innovative Solutions. This means that the assessment of expenditure that would have been incurred in the absence of Innovative Solutions, less the costs incurred in delivering the Innovative Solutions, will be taken into account when calculating the total LRE in period. This is commonly referred as the innovation offset.

[30] In ED1 for ENWL, this is 58% company and 42% customer

7.3 Revisions required for RIIO-ED2

To ensure that a LRR is fit for purpose for RIIO-ED2, we propose that some revisions are made to the design of the mechanism. These fall into three categories and are covered in more detail within this section:

- Adjustment to scope of eligible expenditure
- Change to timings of windows to reflect the move from an eight year to a five-year price control
- Adjustment to risk exposure before adjustments are made

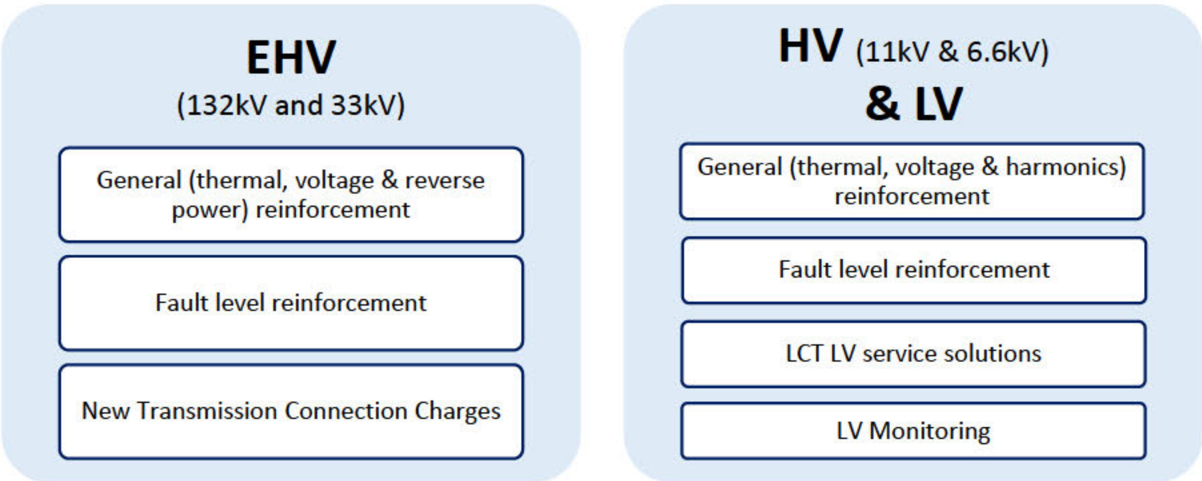
7.3.1 Eligible Expenditure/Scope of re-opener

In RIIO-ED1, Ofgem determined that the scope of expenditure eligible for LRR was widened to account for uncertainty of how and at which voltages the rise in volume of LCTs would have an impact. It was noted that, depending on a DNO's specific network characteristics, volume and clustering of LCTs was likely to differ across DNOs. It was considered that a holistic approach would ensure that the full financial impacts are able to be considered should the re-opener be triggered.

It was also noted that aligning each of the building blocks of LRE to ex-ante allowances whilst aggregating expenditure for the purposes of the re-opener would ensure that DNOs and customers are neutral to trade-offs or boundary issues between funding mechanisms for expenditure categories. We propose that this approach continues for RIIO-ED2, with all eligible LRE treated equally and aggregated together for the purposes of the re-opener. This avoids creating any artificial boundaries or perverse incentives to favour one type of expenditure over another.

We agree that only if, in aggregate at the individual licensee level, the expenditure for LRE exceeds the threshold, should the mechanism be triggered.

Types of load related expenditure are shown in the table below all of which are captured under the existing RIIO-ED1 LRR:



We propose two changes to the scope of eligible expenditure with the below activities excluded:

- New Transmission Connection Point Charges (NTCC)
- LCT LV service solutions

7.3.1.1 New Transmission Connection Point Charges (NTCC)

Transmission Connection Point charges are payments from the DNO to a transmission licensee relating to the number or nature of connections between the distribution and transmission systems.

For the governance of Transmission Connection Charges, Section 14 of the Connection and Use of System Code (CUSC) covers Charging Methodologies including under clause 14.2 The Statement of the Connection Charging Methodology and under clause 14.3 the Calculation of the Basic Annual Connection Charge for an Asset.

In RIIO-ED1, Transmission Connection Points charges are separated by categories of "existing" (TCPs) or "new" (NTCC). "Existing" has the regulatory funding treatment of pass-through and are reset each regulatory period, whilst "new" are treated as part of Load Related Expenditure.

Any "new" charges in period are subsequently re-classified as "existing" in the next price control period and revert to pass-through treatment. Therefore, new charges are only likely to materialise in period for a small number of years as LRE. This seems a largely academic exercise and distorts the view of total transmission point costs. This becomes more pronounced as we move from an eight year to a five-year price control given that charges only arise on commissioning of transmission works which normally take up to five years to plan and construct. As a result, it is likely that new charges could only appear as LRE for a relatively short number of years, before a new price control re-sets these to categorise as existing for the next period.

Whilst distribution companies can undertake some very much 'at the margin' activities to avoid TCPs being necessary, this is largely outside of the companies' control as it is subject to strict charging rules under industry codes as well being impacted by the approach and decisions of National Grid and the wider use of their network. Whilst it was believed in RIIO-ED1 that new TCPs should be treated as LRE to ensure there is an incentive on the companies to be efficient, in reality this has not changed any behaviour or costs as TCPs are only ever incurred when absolutely necessary.

If the network need arises, there is sufficient incentive through the regulatory framework to ensure that a robust process has been followed due to the requirements to co-operate and co-ordinate in a whole system manner, and to consider flexibility services as an alternative to reinforcement.

We therefore propose that a change is made such that both existing and new transmission connection charges are treated as pass-through, and the term New Transmission Connection Point Charges (NTCC) is removed from the category of Load Related Expenditure.

7.3.1.2 LCT LV service solutions

An increasing need in RIIO-ED2 driven by Net Zero aims and the decarbonisation of heat and transport is the need to manage constraints at domestic properties. Constraints can be caused by a range of issues at the service point:

- Being connected to the distribution network via a looped service
- Having a fuse rating which is insufficient for the customers demand needs
- Having a cut-out which is unable to accommodate a new fuse
- Having a service cable which is an insufficient size to meet the customers demand needs

Each of these constraints may prevent a customer connecting and using their LCT in the manner they wish and therefore need to be addressed.

Whilst the need for these activities is clear, the volume is uncertain as variability includes volumes of LCTs in our region, location of these, and individual customer circumstances.

Due to the range of uncertainties associated with the volumes required for these activities and the potential magnitude of expenditure, we propose that this activity is separated from the scope of Load Related Re-opener and Ofgem introduces an uncertainty mechanism specifically for managing constraints at the service point in domestic premises which is able to adjust revenues upwards or downwards accordingly. Further detail on this proposal is shared in Appendix B.

7.3.2 Process & Timings

In RIIO-ED1, there are two windows for DNOs to raise a request for revenue adjustment; 2017 and 2020. Ofgem is also able to trigger the re-opener at the end of the period.

We recognise that RIIO-ED1 is an eight-year period and have given considerable thought to what would be appropriate for the process and time to trigger the re-opener in the five-year RIIO-ED2 period.

We initially considered an annual re-opener, corresponding to DFES updates, that showed actual expenditure to date as well as future forecasts to the end of the period, akin to a rolling business update process. This would give stakeholders and Ofgem full transparency of how forecasts are changing, how actual expenditure is tracking as well as clear visibility on the drivers for change. This also has the benefit of updating revenue on a more frequent basis, smoothing out cashflow and bill impacts. However, this annual process also has the downside of increased regulatory burden for companies, Ofgem and stakeholders. We are also cognisant of minor changes in forecast resulting in potential unnecessary upwards or downwards movements in allowances when they could smooth out over the longer period of time of the RIIO-ED2 price control.

As such, we consider a preferable approach would be to have one window at year three – with applications submitted in May 2025. This is suggested so as to have sufficient time to consider the previous December DFES publication.

Ofgem has proposed a re-opener pipeline for gas distribution and transmission. We support the principle of this for RIIO-ED2 as it would help both companies and Ofgem understand resource implications and allow a constructive dialogue ahead of submissions together with a constructive assessment process that concludes in a timely way.

We suggest that any re-opener application could follow the methodology defined in Ofgem's Business Plan Guidance appendix 7, including:

- Comparison of forecasts underlying RIIO-ED2 plan, actuals and updated forecasts
- Updated plan based on revised forecasts
- Aligning with NDP published in May 2024
- Use of the Best View forecast including stakeholder plans passing due diligence to determine their certainty
- Update in current Load Index (LI) position compared to starting point

7.3.3 Timely delivery for customers enabled by cashflow timings

As indicated in section 7.3.2, one of the benefits of an annual re-opener is that allowances can be regularly updated to reflect actual expenditure requirements. It is important to note that in RIIO-ED1 there is a pronounced time-lag between an Ofgem decision for adjusted allowances and that change being reflected in actual revenue collected.

Presently DNOs are required to set customer prices 15 months ahead of time. This price setting process is bound by strict rules within industry codes that networks must follow and which also impacts how quickly adjusted revenues can be reflected into cashflow. We welcome the intent of Ofgem to review the price/charge setting notice period as part of the wider DUoS reforms and Significant Codes Review (SCR). We are proposing that, as part of the overarching features (as shown in our main Managing Uncertainty annex) a change to the DUoS charges notice period occurs with a shortening from a 15-month to 3-month. This will allow a more agile response to need and ensure that costs and recovery timing are more closely linked. Given it has been signalled that the DUoS reform review will be formally split out from the Access SCR, it is important that Ofgem makes this change to align the notice period for tariff changes to gas distribution to 3 months and do this ahead of RIIO-ED2.

One of the key requirements for a fast acting and agile uncertainty mechanism for LRE is to ensure that companies can access additional allowances as soon as they are required in order to ensure that investment is not unnecessarily delayed. Equally any return to customers if investment is lower than forecast should also be done in a timely manner.

One solution to this cashflow risk is to ensure that companies can include their forecasted use of re-openers in the annual price-setting process. It is critical that this forecast should be a company forecast, consistent with Ofgem regulatory returns, and used for business planning purposes and should not be a stand-alone forecast purely for the use of setting charges. Companies should have a reasonable degree of certainty that the forecast will align with their re-opener applications in due course. We welcome the proposal by Ofgem of adopting this approach to allow companies to make use of forecasts in setting revenues and for these to be included via the PCFM ahead of formal application and Ofgem full approval.

7.3.4 Symmetry

The RIIO-ED1 mechanism acts in a symmetrical manner, adjusting allowances either upwards or downwards. The dead-band and materiality threshold are also symmetrical meaning that the value risk that the company and customer face is equal.

We propose that this symmetrical approach remains the same for RIIO-ED2.

7.3.5 Balance of risk between companies and customers

The RIIO-ED1 mechanism currently has both a dead-band of 20% and an additional materiality value, equal to 1% of base demand revenue multiplied by the TIM rate. For ENWL the combined effect of these equals £34m. This £34m is symmetrical, meaning that the range of expenditure before any adjustment is made varies from £102m to £169m as shown in figure 7.1 for RIIO-ED1.

We consider that 20% is too high for companies and customers to bear in RIIO-ED2 and on reflection was potentially too high for RIIO-ED1. DNO draft plans indicate that RIIO-ED2 LRE will be higher than in RIIO-ED1 as a result of the low carbon transition and other factors. This will be further changed to reflect the uncertainty around outcomes from Access SCR decisions. Should the same dead-band and materiality approach be rolled forward into RIIO-ED2 this would result in a threshold which is neither proportionate nor in customers' interests.

When considering options on this, we concluded that the mechanism should have either a dead-band or a materiality threshold, but not both.

Options would be:

- **Dead-band at a rate substantially lower than 20%**
  This would retain some exposure to both companies and customers in that each will bear the costs/benefits of the difference between actual expenditure and opening allowances if within the dead-band. Companies and customers will share the exposure using the Totex incentive rate in place (for ENWL in ED1 this is 58%/42%)

All expenditure (assessed under the re-opener) that is above or below the dead-band will have allowances adjusted accordingly)

- **Materiality of 0.5% of annual average base demand revenue in line with our proposal for overarching features for re-openers in the ED2 framework**[31]
  For re-openers with a materiality threshold, the requested adjustment should be in excess of this materiality threshold to avoid minor adjustments being requested. Any adjustment made will revise allowances from the baseline ex-ante allowance up or down to the revised value. Any under or over-spend that does not meet the materiality threshold will be subject to TIM under the sharing factor in place.

Our proposal is that the Load Related Re-opener should have a materiality threshold in line with the overarching features for re-openers at 0.5% of annual average base demand revenue. We do not consider a dead-band to be appropriate for RIIO-ED2.

7.3.6 Role of innovation offset

In RIIO-ED1 Ofgem recognised the value of incentivising the use of innovation to reduce overall LRE costs by introducing the concept of “innovation offset” as described in section 7.2.

We agree that incentivisation of innovation should continue into RIIO-ED2 and, whilst we agree with the concept of innovation offset as it is used in RIIO-ED1, we think that the mechanism can be improved by greater transparency and definitions in this area.

Presently it is impossible for stakeholders to see how companies are performing against their load related allowances taking into account both actual expenditure and innovation offset and therefore the total expected LRE. We believe improvements to reporting and a consistent way of calculating the innovation offset would support with this increased transparency and could be simply achieved. For example, you could simply take the value of traditional reinforcement as a baseline, and deduct the cost of achieving the innovative solution, thereby giving you a cost saving, or you could take a whole life approach, considering future costs of innovation, likelihood of future intervention, and also consider the regulatory revenue treatment, meaning that the saving (in period) is substantially lower as the benefit would also be spread over future periods.

It is critical to ensure that Innovation in RIIO-ED2 is defined for the purposes of the LRR. For example, the use of some flexible services such as demand side response is treated as an ‘Innovative Solution’ in RIIO-ED1, however it would not be considered as innovative during RIIO-ED2 given it will have had time to become established and to a certain degree become a business as usual activity. Other flexibility services will have been built into companies’ load plans already and used to reduce the costs of delivering capacity or managing constraints therefore it is important to distinguish for RIIO-ED2 what would be “true innovation” and what are “genuine efficiencies”. Delivering more efficiencies should be encouraged and rewarded accordingly under the Totex Incentive Mechanism. Innovation should also be encouraged, and it is important that this is not disincentivised by the design of any uncertainty mechanism for load.

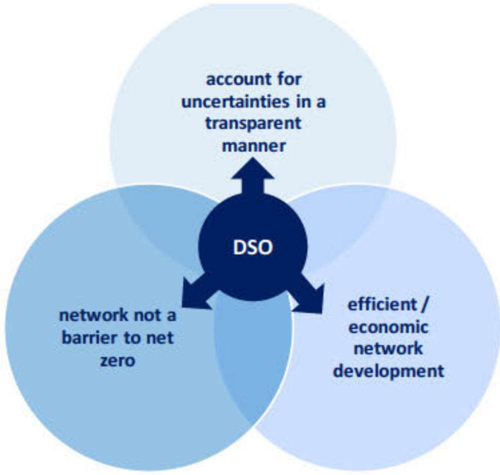
We consider that the RIIO-ED1 definition of Innovative Solutions is broadly fit for RIIO-ED2. Ahead of RIIO-ED1 a list of what was considered to be (and not be) an Innovative Solution was compiled. We suggest that this innovative solution listing approach should be replicated for RIIO-ED2.

[31] Note, some re-openers are proposed to have zero materiality threshold when these are outside of company control

7.3.7 Outputs

Our strategic vision as shown in figure 7.2 is shared within our Load Related Investment Annex A which also provides further details of our proposed outcomes and measures.

Figure 7.2: Strategic vision for LRE



Performance measures are required to ensure we achieve our vision and we consider two key indicators accompanied by transparent evidence and reporting can be used to assess whether our load related investment is proving to be effective. They correspond to our strategic vision outcomes and the two aspects that Ofgem are asking that the metrics consider, namely not being a barrier to customers' connections and ensuring that load investment is efficient. We intend to integrate these parameters to further enhance our network development and refine our internal processes for serving our customers.

Make sure that our network will not be a barrier to net zero

- Measured by how we are meeting our customers needs such as Customer Satisfaction, Time to Connect

Implement an efficient and economic network development

- Measured by Load indices, which can be improved as network visibility increases throughout the period

Manage uncertainties in a transparent manner

- Evidenced by transparent reporting, and public consultations on any re-opener applications

7.3.8 Exclusions

We propose there are limited exclusions for the purposes of the re-opener.
These are:

- New transmission connection point charges (section 7.3.1)
- LCT LV services solutions of domestic properties (Appendix B)
- High Value Projects (section 7.3.10 and section 5.9 of the Managing Uncertainty Annex)
- Material changes to the distribution network as a result of significant nuclear development in the Cumbria region (Appendix C)

7.3.9 Net to Gross

In RIIO-ED1, an accompanying mechanism to the LRR was created, entitled Net to Gross.

Historically, the more costs a DNO recovers via connection charges (over what was forecasted at the time of setting the price control), the better it performs against its allowed revenue, and the more it benefits via the efficiency incentive. At the same time, the current connection charging arrangements prevent DNOs from recovering costs in respect of assets provided in advance of any connection via connection charges. Ofgem considered that the combination of these two factors may incentivise DNOs to wait for customers to request a connection before undertaking significant reinforcement and therefore introduced the Net to Gross mechanism which is intended to true up the difference between the value of relevant expenditure forecast to be funded by connection customers and the actual amount that is contributed. This means Ofgem could allow the DNO more funding or subtract funding, depending on whether the difference is above or below original expectations. The true-up would be carried out across the load-related expenditure, rather than just the connection cost categories. As a result, DNOs should be financially neutral between recovering costs via connection and DUoS charges.

The introduction of changes due to the Access and Forward-Looking Charges Significant Code Review will result in a significantly lower value of reinforcement funded by connection customers. (Current indications are zero contribution for demand customers, and lower contributions for generation and storage customers). Therefore, any benefit perceived for DNOs to wait for a connections request has been effectively removed.

In addition, Ofgem and our stakeholders are challenging DNOs to undertake strategic investment and ensure that efficient investment is made ahead of need, telling us that networks should not be the cause of any delays to the low carbon economy.

The combination of these changes means that the perceived risk of DNOs waiting for connection requests before undertaking reinforcement has been removed, and as such there is no requirement for the Net to Gross to continue into RIIO-ED2. The removal of this unnecessary mechanism supports the aim for simplification of the price control.

7.3.10 High Value Projects

One exclusion in RIIO-ED1 for LRE for the purposes of the re-opener is that if any individual project (whether it is load related expenditure or has another driver) has a value in excess of £25m, it is captured under Ofgem's High Value Project (HVP) mechanism. This means that allowances are essentially ringfenced for that particular project, tied to defined outputs. In RIIO-ED1, the HVP mechanism itself has a re-opener both in period and at the end of the period which allows for revision of existing allowances, plus the opportunity to put forward new projects which emerge or become defined within the period.

We are supportive of the HVP mechanism continuing into RIIO-ED2 and propose that there are two windows in RIIO-ED2. We have one HVP in our baseline plan and our strategic planning work indicates that there may be one further project which may come forward in period, therefore we see a likelihood of the use of this uncertainty mechanism in RIIO-ED2.

We note that the threshold for RIIO-ED1 is £25m, however we propose that this threshold is lowered for RIIO-ED2 to £18m. This value more realistically reflects what we would consider a high value project to be in electricity distribution. More detail on this is shared in section 5.9 of our main Annex.

8. Alternative options

Ofgem has a range of tools to deal with uncertainty, and we have considered each for appropriateness in the space of load related expenditure.

UM type	Purpose	Our view on appropriateness for LRE
Re-opener	To decide, within a price control period, on additional allowances to deliver a project or activity once there is more certainty on the needs case, project scope or quantities, or cost.	Preferred option
Volume Driver	To adjust allowances in line with the actual volume of work delivered, where the volume is uncertain	See detailed comments below in section 8.1
Pass-through	To adjust allowances for costs incurred by the DNO over which they have limited control and that, in general, Ofgem consider the full cost of which should be recoverable (e.g. business rates)	Not appropriate as DNO does have some control – moving to pass-through removes any incentive on the DNO to contain costs and drive efficiencies – not in consumers interests.
Indexation	To provide network companies and consumers some protection against the risk that outturn prices are different to those that were forecasted when setting the price control, e.g. general price inflation or cost pressures.	Not appropriate as this is intended to deal with a different type of uncertainty.
Use it or lose it	To adjust allowances where the need for work has been identified, but the specific nature of work or costs are uncertain.	Not appropriate as the uncertainty is the scale of need.

8.1 Volume Driver appraisal

We had previously considered a volume driver as an appropriate uncertainty mechanism solution for LRE as it removes the need for Ofgem to assess re-opener applications and provides an automatic way of adjusting allowances as expenditure is incurred. We recognise that Ofgem, in its December 2020 SSMD, stated its intent to explore the use of an automated mechanism as an option.

Companies and stakeholders have identified two key challenges with a volume driver approach to LRE;

i) how to set a fair unit cost
ii) how to ensure that the risk of asset stranding is minimised.

Since 2019, industry working groups have discussed these challenges and, as yet, there are no detailed proposals to overcome these, however we understand that Ofgem engaged CEPA in September 2021 to look at how a volume driver could work for ED2.

<u>Unit cost</u>

The only viable option to address the unit cost challenge appears to be a combination of re-openers and multiple volume drivers for each voltage and type of work; this is likely to result in multiple different categories. We consider this would drive complexity, reduce transparency and create artificial barriers in spend categories, removing the principle of all LRE being assessed in aggregate and treated equally.

RIIO-ED2 will also see a much greater use of flexibility services as an alternative to traditional asset-based reinforcement. We have yet to see what impact this will have on overall expenditure and therefore the setting and calibration of unit costs will be increasingly difficult for RIIO-ED2.

Asset stranding risk

The only option currently brought forward to address the risk of asset stranding, or a volume driver being used without limitations, is the use of a network utilisation measure.

Presently the only measure of network utilisation in place as part of the RIIO-ED1 regulatory framework is Load Indices. Load Indices express maximum load compared to thermal rating, and are a helpful measure of network loading, however they cannot be relied on in isolation as they do have some limitations and cannot be used for:

- Giving accurate indications where we don't have data i.e. LV
- Where we have taper circuits
- Expressing fault levels
- Voltage drop/rise constraints
- Power quality
- Limitations at other cardinal loading points such as minimum demand/max export
- The change in ratings as our network loading is changing to a continuous nature through the use of ANM and smart charging for example

In the absence of greater monitoring of the network, and still relatively low levels of smart meters that are able to provide network data, a reliable and representative view of network utilisation is not yet available.

We and many DNOs, based on their draft plans, are proposing a significant investment in LV monitoring during RIIO-ED2. A combination of this, together with completion of the smart meter rollout during in RIIO-ED2 will provide networks with more granular data that they have never had before. At that future point, network utilisation measures can be developed and could be in place for in RIIO-ED3.

Conclusion

The use of a volume driver(s) does not cover the full range of load related expenditure; there are challenges around circuits, likely different treatment needed for extra high voltage (primary) and volume drivers would not cover other programmes such as fault level or LV monitoring. This would mean that the overall cost base of LRE would have multiple layers of regulatory treatment, creating unnecessary complexity.

We still consider the use of a volume driver(s) for LRE may be a viable solution in the future, as it has some attractive features however we suggest the option is not appropriate for RIIO-ED2 given the challenges and should be revisited for RIIO-ED3. During RIIO-ED2 more will be known about the impact of flexibility markets, there will be greater certainty over the future of heat and we will have much more granular visibility of network utilisation. A volume driver solution can be explored in a more informed way well in advance of RIIO-ED3.

8.2 No Uncertainty Mechanism

An alternative to the use of any uncertainty mechanism is to set ex-ante allowances with no corresponding uncertainty mechanism. This has been discounted by ourselves and by Ofgem in its SSMD due to the known difficulty of selecting an appropriate level of ex-ante allowances that provides for the necessary investment whilst protecting customers from forecasting risk.

To demonstrate this, there are downsides with setting allowances at either the lowest, mid-point or highest scenario:

Lowest: brings too high a risk of insufficient funding and therefore barriers to Net Zero should any other scenario be realised. Without an uncertainty mechanism companies will be unable to access the necessary funding to bring further investment that may be needed by a higher scenario.

Mid-point: may theoretically seem an attractive solution but gives no protection to customers or companies should scenarios either side of this be realised.
Highest: whilst it will provide DNOs with adequate funding to deliver any requirements they are likely to face in period and ensure networks are not a blocker to Net Zero aims, it exposes customers to the maximum forecasting risk, and will increase customer bills, likely unnecessarily, in the short term leaving companies with the opportunity of windfall gains should any lower scenario be realised.

We consider a well-designed uncertainty mechanism and means by which to adjust revenues based on forecast of UM usage, combined with ex-ante funding linked to a central forecast is the most appropriate mix.

9. Relationship with other re-openers

It is crucial that there is clear delineation in the context of LRE between the purpose of each uncertainty mechanism and re-opener to ensure clarity in their operation.
The RIIO-ED2 framework currently includes a Net Zero Re-opener and Ofgem is considering the inclusion of a re-opener relating to the impact of the Access SCR decisions. We share within this section each of the re-openers that we consider closely linked and how their use can be clearly distinguished.

Net Zero Re-opener	Regulatory Changes Re-opener	Moorside Re-opener	High Value Projects	LRE Re-opener
• To amend the price control in response to changes connected to meeting Net Zero carbon targets that have an effect on the costs and outputs of licensees	• To amend the price control to enact decisions made by Significant Code Reviews and other major Ofgem or Government programmes of work	• To amend the price control in response to decisions to site nuclear generation within the Cumbria region	• To amend the price control to reflect changes to existing HVPs or to introduce new HVPs annd their deliverables	• To amend allowances to reflect changes in expenditure requirements for load related activities.

Net Zero Re-opener should be used in extreme circumstances driven by changes such as legislative targets, government policy, or other such material events. This could include, for example, a decision that decarbonisation of heat would be solely by electrification resulting in a change of responsibility for DNOs. We maintain our view that this should not be an Authority only trigger and should also be able to be triggered by the company.

Regulatory Changes Re-opener should be used to revise the price control to reflect all changes driven by decisions from SCR and other key regulatory and policy programmes of work such as Full Chain Flexibility EXCEPT those that impact LRE requirements. Such impacts should be managed through the LRE. Use of this Regulatory Changes Re-opener would therefore be for costs relating to people and system (indirect) costs and other overheads driven by enabling the LRE direct changes required. This would also encompass costs which are generally categorised as Closely Associated Indirects, as a consequence of decisions.

One example may be the need for additional designers and project managers as a result of increased work driven by changes linked to a change to a shallow charging boundary. Whilst some additional resource is envisaged as a result of low carbon transition and linked to our Central Outlook scenario, it would be inappropriate to include large changes ahead of any impact being seen in period, however it is clear that as the scale of LRE increases or decreases, so do the scale of associated indirect costs. As these changes that trigger the need are driven by a third party outside of DNO control we propose that the Regulatory Changes Re-opener should have zero materiality threshold in line with other re-openers that are outside of company control.

Moorside Re-opener should be used to revise the price control to reflect work needed in Cumbria associated with the build and connection of nuclear generation, whether this be a large nuclear power station sited, or Small Modular Reactors (SMR).

High Value Projects should be used where projects meet a value threshold. The driver could be load related but is not limited to this and could be used for any project by any driver which meets the value threshold set.

LRE Re-opener should be used for all changes in LRE requirements regardless of whether it is driven by the pace of decarbonisation, changes driven by Access SCR decisions or other reasons. The single exception to this is expenditure related to nuclear development in Cumbria which we propose should remain within the specific Moorside re-opener as this will be unique, ring-fenced and the circumstances lend itself to a bespoke mechanism.

10. Cost treatment in BPDTs

The load investment plan relates to the following business plan data tables and their corresponding commentaries:

- C2 – Customer funded reinforcement
- CV1 - Primary reinforcement
- CV2 - Secondary reinforcement
- CV3 - Fault level reinforcement
- CV11 – IT equipment
- M14 - Drivers
- M19 - DSO
- M20 - LCT

Uncertainty mechanisms are detailed in table M13 whilst Access SCR impacts are shown in table M30 and described further in Annex 3, Appendix C.

11. Conclusion/Analysis of proposal

Load Related Expenditure (LRE) is a critical component of a DNO's business plan; it facilitates customers' requirements, enables economic and regional growth and supports the transition to Net Zero.

LRE has a range of drivers and a number of associated uncertainties, all of which must be carefully considered when designing an Uncertainty Mechanism (UM).

The approach for LRE in previous price controls has served customers well for many years, and our proposal takes the existing elements of the RIIO-ED1 mechanisms, and with a limited number of revisions ensure that they continue to be fit for purpose for the challenges we will face in RIIO-ED2.

Our proposal takes a holistic look at all the components of LRE and delivers Ofgem's aim of simplification in the price control where possible. This comprises three key mechanisms, each dealing with uncertainty in a slightly different manner. These three combined are complementary and provide a whole solution to the range of load related expenditure that may be incurred.

This way of managing uncertainty in this critical aspect of DNO plans will:

- Be a strong enabler of Net Zero at lowest cost
- Protect customers from forecasting risk
- Support strategic investment
- Ensure all LRE is treated equally, including flexibility services
- Cover all needs regardless of driver, e.g. demand, generation, economic growth etc
- Decrease or increase allowances as required
- Avoid artificial boundaries for expenditure
- Encourage innovation

The LRR is an established mechanism, well understood and transparent.

Appendix B: Providing LCT LV Service Solutions – Our volume driver uncertainty mechanism

This appendix sets out our proposal to include a common volume driver to manage the uncertainty around the volumes associated with the need to manage service related issues to facilitate the Net Zero transition and decarbonisation of heat and transport.

1 December 2021

Appendix B – Providing LCT LV Service Solutions – Our volume driver uncertainty mechanism

1. Introduction

1.1 Introduction

This appendix lays out our proposed approach for dealing with the uncertainties associated with the management of constraints at domestic properties caused by issues at the service point. Such constraints could impact on customers' abilities to decarbonise their heating and transport. The most material (in terms of costs) of these constraints is caused where customers are connected to the distribution network via a looped service.

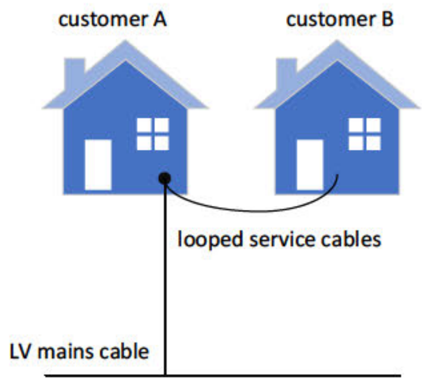
This appendix focuses mainly on this looped service issue, with all other service related issues are covered exclusively within section 5.

1.2 What is a looped service?

A looped property is where two or more domestic properties share the same service cable as shown in figure 1.1.

This is where a single service cable is taken from the low voltage (LV) mains cable and is "looped" from one property to the next to provide an electricity connection. This means that the electrical demand of two or more properties is supplied via a single service cable, rather than one service cable per property connected directly to the mains cable. This proposed uncertainty mechanism deals only with loops which are underground. Looped properties which are connected by overhead cables are generally called mural wiring and this is covered under a separate document (EJP NNARM7-Condition based mural wiring replacement).

Figure 1.1 – example of a looped service



Historically, looped services were installed as an economic and efficient way of connecting new properties mainly in the 1960s and 70s and were commonly used for new terraced houses and new housing estates. This was a safe and efficient way of constructing the network at that time and has provided satisfactory performance for many decades based on average domestic demand and network usage.

It is estimated that around 20% of domestic properties (approx. 480,000) in our region are connected via a looped service. Our base assumption is that one loop connects two properties and it should be noted that one of these already has a direct service cable to it, therefore the number of master service cables is half the number of connected customers as shown in table 1.2.

Table 1.2 - numbers of households impacted

	Number of connected customers 000's	Number of service cables 000's
Looped	480	240
Direct service	1900	1900
Total	2380	2140

1.3 What is the issue?

As the electrification of transport and heating are key elements of UK's transition to Net Zero carbon, the electricity demand of domestic customers who install an electric vehicle (EV) charger and/or a heat pump is expected to increase significantly. The uptake of EV volumes is forecasted to increase by over 60 times the current levels during the RIIO-ED2 period. This will lead to large numbers of EV charge points being installed at domestic dwellings.

As we enter this world where customer demand and network usage are starting to change as a result of the uptake of EVs and HPs, looped services can pose a safety risk where network capacity is exceeded when such LCTs are connected. It is important to remove this risk and ensure that the electrical network is not a barrier to the uptake of Low Carbon Technologies (LCTs) necessary to meet the national Net Zero target.

The typical arrangement of a looped service consists of:

- an LV mains cable that is connected to the local secondary network substation;
- one service cable that is typically rated at 100-120A and connects the LV mains with the group of two or more looped properties;
- two or more cut-outs depending on the number of properties looped that are typically rated at 60A and connect the adjacent properties with the service cable.

This arrangement has traditionally allowed domestic customers to absorb up to 60A from the network, allowing for a couple of high demand domestic appliances. As more customers adopt LCTs, a domestic EV charger could bring an incremental demand of circa +7.5kW (+32A) and a heat pump (HP) another 5 to 15kW (+20 to 60A) approximately. Therefore, if a domestic customer on a looped property installs a single EV charger rated at 7.5kW then the total demand could easily exceed the 60A rating of the cut-out. With a second LCT installed on the same group of looped properties, the aggregated peak demand of both of them could exceed the 100A rating of the service cable during coincident use of the devices.

Apart from the real risk to exceed the capacity of service cables, there are potential safety risks for domestic customers. More specifically, the full load of all the dwellings on the loop flows through the first section of the loop and the termination at the first cut-out. Crucially, this equipment is effectively electrically unprotected. Consequently, there is a risk of overheating and in extreme cases even fire, which we wish to address to remain within the scope of the Electricity Safety, Quality and Continuity Regulations (ESQCR) 2002.

As a result, network intervention is required to ensure that customers are able to connect their new LCT(s) safely and in a timely manner.

1.4 Our forecasted impact

As more national policies are supporting the adoption of LCTs in the UK's transition to Net Zero carbon by 2050, there is a need to provide adequate network capacity to all domestic customers that adopt LCTs and are supplied via looped services. Based on consumer choice modelling in our DFES 2020[32] forecasts that consider expected national policies for LCTs, table 1.3 shows the forecast EV and HP update compared to the start point at 2019/20.

[32] Distribution Future Electricity Scenarios (DFES) 2020, Electricity North West Ltd, online: www.enwl.co.uk/dfes

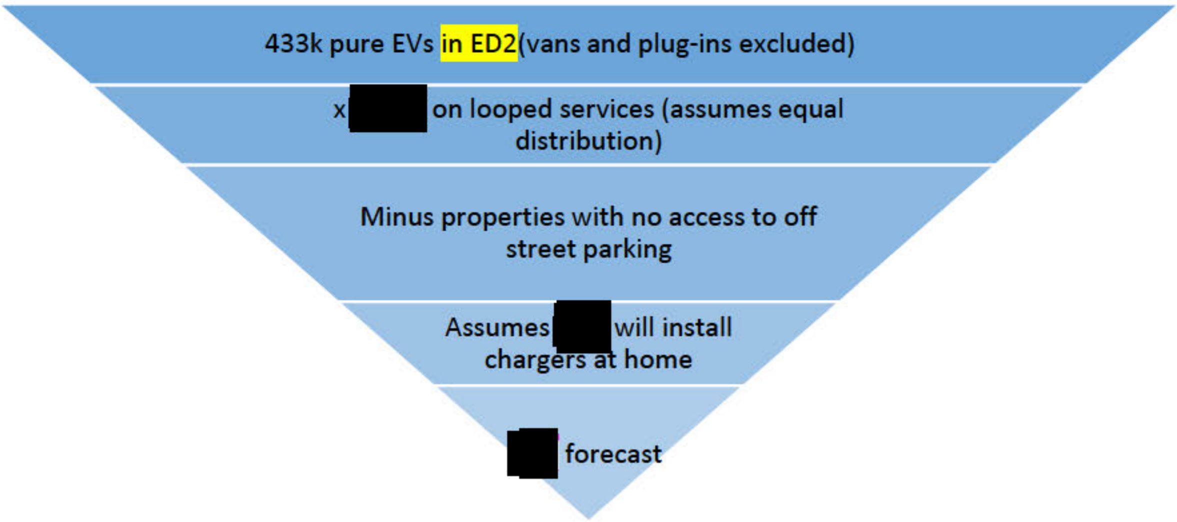
Table 1.3 – Forecast EV and HPs

Scenario	2019/20	2022/23	2027/28
Central Outlook: national policies driving electrification of transport, limited levels of electrification of heating)	9.4k EVs 13.1k HPs	92.3k EVs 25.4k HPs	638k EVs 68.4k HPs

We have taken a cautious approach to estimate the number of properties in our region that will require unlooping during RIIO-ED2. Unlooping is only considered to be required when EV chargers are connected to properties fed by a looped service (this avoids double-counting where a customer may take up both a HP and an EV).

From a starting point assumption of our 'Central Outlook' of 638k EVs by the end of RIIO-ED2, a step by step process (shown in figure 1.4) has been taken to estimate unlooping requirements in RIIO-ED2, resulting in our forecast that [redacted] looped services may need to be resolved during RIIO-ED2.

Figure 1.4 – forecast methodology



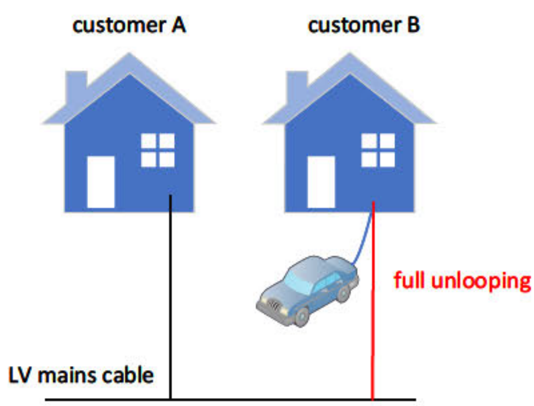
2. Intervention options

2.1 Full unlooping

Full unlooping interventions, as shown in Figure 2.1, is where the loop is effectively removed so that the previously looped properties are connected to the LV mains cable via separate service cables, i.e. 100A each. Although this has some associated disruption to the customers, it future proofs the connection by facilitating the adoption of LCTs across both domestic customers.

To unloop a property both parties will experience some level of disruption, however we will work with customers to agree the best approach, minimise disruption and always ensure reinstatement at the end of works. The level of disruption will inevitably be part of the decision-making process for the

Figure 2.1 – example of removal of constraint



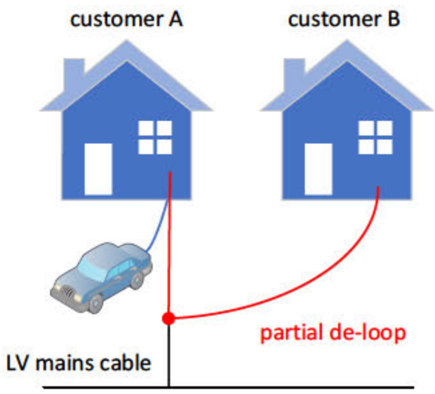
customer, particularly if it is not they who want to adopt an LCT and they are experiencing the disruption to benefit their neighbour.

Once completed, both properties have a full independent connection to the mains cable and will face no further barriers to LCT adoption.

2.2 Partial unlooping

Partial un-looping interventions, as shown in Figure 2.2, is where the loop effectively moves outside the domestic property. Specifically, the loop is breech jointed onto the existing service underground and the cut-outs are uprated from typically 60A to 100A each. This removes the danger of assets above ground overheating and failing, making the installation compliant with the Electricity Safety, Quality and Continuity Regulations (ESQCR). It is also a less invasive approach than full unlooping and therefore minimises disruption to the customer.

Figure 2.2 – example of removal of constraint



2.3 Innovative solutions

As has been found with other network challenges, it is possible that innovative solutions to the constraint issue on the service and loops may come forward within the RIIO-ED2 period to improve the customer experience, generate cost efficiencies, or both. This should be encouraged and not restricted by any uncertainty mechanism.

To account for a range of interventions we propose that the volume count used to trigger the mechanism is the number of properties which were previously constrained and are now LCT enabled.

2.4 Unit costs

The unit cost for a full unloop, as described in section 2.1, is [redacted] and the unit cost for a partial un-loop, as described in section 2.2, is [redacted]. These costs are made up of both direct (physical activities) and indirect (administration and support) costs.

It is unclear how many partial unloops and how many full unloops we will need to do, however based on assumptions for property splits[33], we have estimated this is to be [redacted] partial and [redacted] full unloops.

Using a mix of the interventions at the percentage assumptions above gives a blended intervention cost of [redacted]. On the basis that the vast majority of loops will have two properties connected, the intervention cost is divided by two to give a cost allowance per volume of [redacted]

Our RIIO-ED1 experience from actual installations has shown that in order to minimise customer disturbance, any reinstatement works require bringing the customer driveways and gardens as close as possible to their prior condition which in turn drives cost.

It is important to note that given this work will generally be at the request of the customer, and involve liaison with at least two households, the indirect costs associated with management of this work, administrative and co-ordination costs are an integral component of the service we need to provide. Our recent experience has shown that customers installing LCTs have many queries and require our

[33] Housing stock is assumed to follow the national split based on the housing review data

assistance through connection and network change processes because dealing with us as their distribution network operator is new to them. Costs of our support will be more substantial than if we were working on our own land or our own assets with no domestic customer involvement. This increased co-ordination cost has been factored in to the intervention cost calculations because it is directly proportional to the volume of service solutions.

Section 4.5 provides more details on this calculation and assumptions for mix of interventions.

3. Materiality of issue

Based on our 'Central Outlook' forecast of 32k looped services requiring intervention during RIIO-ED2, and an assumption that there will be a mix of solutions applied based on property type, the forecast expenditure in RIIO-ED2 would be £102.6m.

Although we are confident in the robust forecasting methodology informing the expected number of EVs in our region, there are significant uncertainties around the number of interventions that we will be required to undertake due to the dependence on our customers' behaviours and the location of the LCT take-up. The number of services we need to act on will be affected by the location of LCT up-take, whether customers accept the potential physical disruption of unlooping and whether they will need to charge their vehicle at home or can do that at an alternative location such as work or a charging hub.

In an accelerated scenario where EV take-up is higher than our 'Central Outlook' forecast, then the figures would increase proportionately. Conversely if up-take is not in line for our forecasts, we could see the figure required fall lower than [redacted]

It is for this reason that the full £102.6m based on our 'Central Outlook' is not being requested via ex-ante funding, and we propose a volume driver to manage this uncertainty.

4. Our proposal

4.1 Summary of proposal

Area	Our proposal
Mechanism type	Volume driver (annual) – annual volumes multiplied by unit cost
Unit cost	[redacted] per property which was previously constrained and is now LCT enabled.
Covering	Cost of removal of LCT constraint caused by a looped supply
Materiality threshold	Zero, covered by annually adjusting volume driver
Regulatory reporting and evidence	Included in RRP and AIP (or equivalent in RIIO-ED2) frameworks

4.2 Rationale for treatment via an Uncertainty Mechanism (UM)

In RIIO-ED1, unlooping has been undertaken at a smaller scale compared to that potentially required in RIIO-ED2, partly due to the lower than anticipated uptake of EVs in our region. This has been reported as load related expenditure (LRE) and is in scope of the current RIIO-ED1 load related re-opener. Volumes are already increasing in RIIO-ED1 and we expect this trend to continue. We forecast that the run rate as we exit RIIO-ED1 will be in line with the assumptions for the first year of RIIO-ED2.

For RIIO-ED2, all published draft DNO plans indicated that unlooping will be a significant activity to ensure that this blocker to LCT uptake can be removed. In our area we estimate c20% of domestic properties have a looped service and these will need to be resolved over multiple price control periods, starting in earnest in RIIO-ED2.

Based on our experience in RIIO-ED1 we increasing our understanding of the unit cost, however we have less certainty over the volumes as drivers of variability includes:

- volume of EVs which will connect in our region,
- location of these EVs, i.e. whether they will be in looped service properties; and
- customer acceptability for the intervention.

Due to the range of uncertainties associated with the volume required for this activity, the discrete nature of the interventions, and the potential magnitude of expenditure, we propose that this activity is separated from LRE and that Ofgem introduce an uncertainty mechanism specifically for managing looped constraints in domestic premises which is able to adjust revenues upwards or downwards as required.

4.3 Type of uncertainty mechanism (UM)

We have certainty over the need, and certainty over the unit cost, however the key uncertainty is related to the volumes of work required in the period for the reasons highlighted in section 4.2.

Given these characteristics and the toolbox of UMs available to Ofgem, we propose that the most appropriate UM for this activity is a volume driver.

Ofgem introduced a volume driver for Smart Meter interventions in RIIO-ED1. We see a number of similarities to this for the unlooping programme and therefore have modelled our proposal for an unlooping volume driver on the Smart Meter volume driver.

4.4 Setting a baseline and balancing risk to customers

As described in section 3, our forecast is £102.6m for [redacted] interventions however, this volume is uncertain for the reasons previously described and it is important to protect customers from forecasting risk. Conversely the need for these activities is certain and therefore it is equally important to provide companies with sufficient ex-ante allowances to ensure the regulatory framework and funding structures are not a barrier to the uptake of LCTs.

It is for this reason that we propose an ex-ante allowance is set with a volume driver which can flex revenues upwards or downwards as required.

In RIIO-ED1, the need and unit cost for Smart Meter interventions were well understood, while the volume was the unknown. Ofgem took the approach of setting a modest ex-ante allowance, assuming that for every 100 Smart Meters installed, the DNO would need to intervene in two of these, therefore setting a cautious intervention rate. All volumes that varied from this baseline were trued-up annually through regulatory reporting and the annual iteration process.

Whilst the methodology for estimating unlooping requirements is more complex (as described in the forecasting process in section 1.4), a more simplistic percentage-based approach could be used to set baseline funding. As we have previously described, although we are confident in the robust forecasting methodology informing the expected number of EVs in our region, there are significant uncertainties around the number of interventions that we will be required to undertake due to the dependence on our customers' behaviours and the location of the EV take-up. The number of services we need to act on will be affected by whether customers accept the potential physical disruption of unlooping and whether they will need to charge their vehicle at home or can do that at work or a charging hub.

Our forecast expenditure is in line with the assumptions described in section 1.4 and is £102.6m for [redacted] interventions. [redacted]

We are however, proposing a lower ex-ante allowance which is a no-regrets value. [redacted]

- up-take numbers and EV availability
- location of EVs – i.e. we may see clustering more in detached houses (considered highly unlikely to have a looped service)
- customer choice on EV charging i.e. some may have access via work or other means
- customer acceptability i.e. decision on level of disruption and choice of intervention
- EV ownership model i.e. EVs may become a mobility solution product or EV charging may be centrally bundled with ownership

This baseline value is approximately 20% of the forecast RIIO-ED2 requirement. We are already increasing our activity in this area in RIIO-ED1, and as we further increase our delivery capability and number of interventions, these figures are in line with our expected run-rate as we exit RIIO-ED1.

Any interventions undertaken that are above, or below, this ex-ante allowance each year would then be reported annual through regulatory reporting and trued-up via the annual iteration process (AIP)[35].

There should be no regulatory cap on volumes as this risks deterring companies from undertaking enabling Net Zero works and could limit the ability for customers to connect their LCTs in a safe and timely manner.

We therefore propose a baseline allowance equal to £20.1m for [redacted] interventions which can then be flexed upwards or downwards as required. [redacted]

Setting baseline allowances in this way places the risk on volumes with the customer. However, by selecting a baseline assumption which is certain under all scenarios, customers can be protected from the risk of high forecasts and customer bills are only increased as the needed volumes increase above baseline.

4.5 Setting a unit cost and balancing risk to customers

It is appropriate for DNOs to bear the unit cost risk as they are best placed to manage this. Given the unlooping interventions are established activities in RIIO-ED1, we have confidence on the unit cost in our plan. These costs are modelled on a range of scenarios, but on the assumption that the majority of work will be where two properties are connected. We anticipate the cases where there are three or four properties connected to be rarer.

The intervention volumes in year one of RIIO-ED2 are broadly in line with the expected run rate as we exit RIIO-ED1, increasing gradually in line with EV up-takes over the course of the period.

[34] 6.3k interventions would benefit c13k domestic properties

[35] Or equivalent in RIIO-ED2

Using a mix of the interventions at the percentage assumptions gives a blended intervention cost of [redacted] as shown in table 4.1.

Table 4.1 – Intervention forecast and unit cost breakdown

Intervention		FY24	FY25	FY26	FY27	FY28	Total
	Intervention #	**13%**	**16%**	**20%**	**22%**	**29%**	**100%**
Partial unlooping	[redacted]						
Full unlooping	[redacted]						
	Total	**816**	**1,004**	**1,255**	**1,381**	**1,820**	**6,275**
	Unit cost	Cost £000's	Cost £000's	Cost £000's	Cost £000's	Cost £000's	Cost £000's
Partial unlooping	[redacted]						
Full unlooping	[redacted]						
	[redacted]						
Average intervention cost	[redacted]						

We propose that the unit cost per volume is calculated on a per property basis rather than per intervention. That is to say one intervention has the output count of two properties. This is proposed because it aligns the output with the other service solution elements of the proposed volume driver. For example, one property is enabled to connect a LCT for each fuse replacement or installation of a new cut-out.

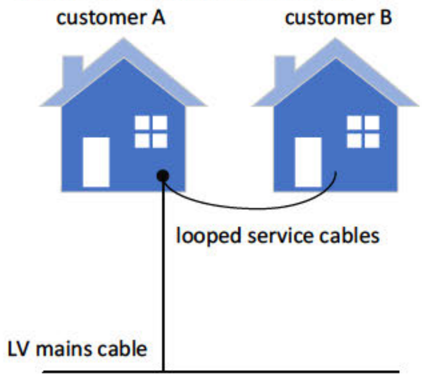
This is calculated on the assumption that the vast majority of loops will have two properties connected, and therefore the intervention cost divided by two would give a unit cost allowance per volume of [redacted]

4.6 What are the outputs

The unlooping intervention will affect more than one property, in most cases this will be two, however it could be up to 4.

It is important to note that as shown in figure 4.2 both customers are constrained, not just customer B.

Figure 4.2 – example of constraint



Customer A has a constraint to connecting an LCT because they are bearing the load for both properties through their connection.

Customer B has a constraint due to them not having a direct service and the potential for overheating of the cut-out in customer A's house due to customer B's increased load.

We propose that the volume count used to trigger the mechanism is the number of properties which were previously constrained and are now LCT enabled. For example, in the case of customer A (already connected via mains) and customer B (connected via the loop) this would equal two properties.

We suggest that memo reporting similar to the approach taken for Rising Lateral Mains in CV17 is adopted for unlooping to allow Ofgem to see the work that has been undertaken. An example of how such reporting could work is shown in table 4.3.

Table 4.3 – Example memo reporting table

	2024 #	2025 #	2026 #	2027 #	2028 #	Total #
# Interventions	[redacted]					
# Properties						

4.7 Adjustment process

The volume driver will work by each year comparing the baseline allowances to the actual volumes reported within the annual regulatory reporting process. Any variance on volumes will be adjusted through the AIP[36] and an upwards or downwards adjustment would be made to future allowed revenue.

An illustrative example is shared in figure 4.4. The £m adjustment is calculated as the difference in volumes multiplied by the fixed unit cost.

Table 4.4 – Adjustment example

Based on U/C [redacted]	FY24	FY25	FY26	FY27	FY28	Total
Ex-ante Allowances	[redacted]					
Opening Volumes # properties						
Opening Volumes £m allowances						
Actual Reporting						
Annual reported volumes (#)						
Variance to opening volumes (#)						
£m Adjustment						

[36] Or equivalent in RIIO-ED2

Any variance to unit cost will be managed through the Totex Incentive Mechanism (TIM) meaning that customers/DNO share in the value of any under or outperformance against the efficient unit cost set for this activity. This retains the incentive on efficiency and drives potential for benefits to customers. This approach also shares any cost increases between the DNO and customers if spending more than the unit rate set for RIIO-ED2.

4.8 Forecasted adjustment

As with all other uncertainty mechanisms for RIIO-ED2, it is crucial that revenue and cashflow is adjusted in line with needs as they arise to ensure that the RIIO-ED2 framework is agile and fast-acting and does not become a barrier to Net Zero.

As we explain in section 3 of our Managing Uncertainty Annex, we anticipate that calculated revenue can be adjusted, via the Price Control Financial Model (PCFM) functionality, to reflect forecasts of the use of this volume driver as we gain increased insight into customer behaviour and the location of LCTs.

5. Other Service Related Constraints

As described in section 1 of this Appendix and Section 4.2 of the main Managing Uncertainty Annex, there are other constraints at the service point that may cause domestic customers issues where they may not be able to connect their LCT in the manner and at the time in which they wish.

It is important that these other barriers to Net Zero and decarbonisation aims of our customers are also addressed.

Our recent experience (throughout 2021) is that for all customer LCT enquiries, c.70% need no intervention and can proceed as the customer has planned, whilst c.30% need work undertaken at the service point. Many of these are the unlooping referred to previously, however some fall under the categories detailed below.

There are three other constraints we see customers experiencing apart from unlooping which has been extensively covered in this appendix:

- Insufficient fuse rating
- Insufficient cut-out
- Insufficient service cable

Each will need rectification as described below.

5.1 Enhancing the fuse rating and upgrading the cut-out

In the case of an enquiry about installation of an LCT, the installer provides the current fuse rating and total maximum demand, including the LCT. If the maximum demand exceeds the fuse rating then the DNO will attend site and complete a fuse upgrade, i.e. installing a larger size fuse.

There are certain types of cut-outs that are unable to accept a fuse upgrade. In these instances, the old cut-out needs to be removed and a new cut-out capable of accepting the larger fuse size installed. Work to do this can be done either "live" or "dead" depending on circumstances. We have some instances where the operative is able to complete the change whilst keeping the incoming service cable "live". Depending on the type of cut-out, the cable may need to be made "dead" which would involve excavation to complete a safety cut on the existing service cable to temporarily remove power to make the property dead, allowing us to safely remove the old cut-out and install the new upgraded one. The existing service cable would then be reconnected to make live once again.

As we would not replace a cut-out (in these circumstances) unless it needed to be changed to accommodate the larger size fuse, we have combined our assumptions for the cut-out and fuses to be one combined single unit rate. Our view of efficient costs based on our experience to date is [redacted] per service intervention. This includes both direct and indirect costs.

For the avoidance of doubt, we may change cut-outs for other purposes, either associated to the Smart Meter roll-out programme, in a fault situation, or as part of asset replacement. In all these cases, the driver of the work dictates the regulatory treatment.

The only circumstances where this unit rate of [redacted] for service interventions applies is proposed as a result of a customer enquiry due to a change of use or demand at their premises.

5.2 Uprating the Service Cable

Every service cable has a maximum current rating based on the size of the conductor. If a property has an inadequately rated service cable (typically 16mm), we need to install a new larger cable. In order to do this, an excavation will be required, and new service cable installed, referred to as a service cable uprate. We have had limited experience of the need for this to date, however our records indicate the presence of these cables within our network, and therefore as LCT demand increases, we expect to see the need for such service cable replacements to increase accordingly, though the volume of these is very uncertain.

Unit cost for this work is [redacted] per service cable uprate.

5.3 Drivers of Uncertainty

Whilst the volume numbers in 2020/21 were relatively modest as can be seen in table C2 of the BPDTs, we are seeing a year on year increase, and we have seen significant increase already in 2021. This is a trend we expect to continue as more customers begin their journey of decarbonisation of their transport and heat.

We also understand that Ofgem has recently been considering the treatment of funding of these types of work to understand and remove any differences across DNO companies. We anticipate that guidance may be issued soon to indicate that all of this type of work, regardless of whether the driver is LCT or other customer need [redacted] Presently we charge customers who need service related work which is not related to the installation of an LCT. A change to this will naturally result in higher overall spends by the DNO as what was [redacted] within the price control.

These two changing elements bring uncertainty on the volume and value of the DUoS funded work required as we move into RIIO-ED2.

5.4 Setting a baseline and balancing risk to customers

Given the uncertainty around the volume of service related work that will be required in RIIO-ED2, we have proposed a baseline ex-ante allowance in line with the latest available year of data in RIIO-ED1 (2020/21).

In order to avoid exposing customers to a forecasting risk in an area which has relatively modest requirements at present, we have set our baseline on the replacement of fuse and cut-outs only, as we have more experience of this work and less historical data particularly on the volume of service cable uprates. A bespoke review of our costs has been used to develop the specific service cable replacement unit cost.

Intervention # Baseline	FY24	FY25	FY26	FY27	FY28	Total
Fuse & cut-outs	[redacted]					
Service cable						

Baseline £	Cost £	Cost £000's	Cost £000's	Cost £000's	Cost £000's	Cost £000's	Cost £000's
Fuse & cut-outs	[redacted]						
Service cable							

We suggest that any deviation to these volumes is managed through the creation of a volume driver similar in concept to our proposal for managing the uncertainty around unlooping of services as detailed in sections 1 to 4 of this Appendix.

The volume driver would have two rates for the two activities:

- [redacted] for fuse upgrade/cut-out replacement
- [redacted] for service cable uprate

Using the same profile of increase as we have for the unlooping work (which is linked to our central DFES assumptions on LCT uptakes), we estimate that the volume driver for service related activities could be [redacted] as shown in the table below.

UM Potential	Cost £	Cost £000's	Cost £000's	Cost £000's	Cost £000's	Cost £000's	Cost £000's
Fuse & cut-outs	[redacted]						
Service cable							

6. Cost treatment in our Final Business Plan

Costs and volumes are displayed in CV2 for unlooping, C2 for all other service related issues and M13 tables for both within the BPDTs.

7. Justification for mechanism

The use of volume drivers to deal with this service related uncertainty is the most appropriate treatment to apply in these circumstances. The use of a volume driver enables revenue to be flexed to meet actual requirements in period, and setting a fixed unit cost, with TIM applicability provides the incentive for innovation and cost efficiency.

Providing an ex-ante allowance provides sufficient funding to the DNO to ensure the activity can be delivered at a rate in line with RIIO-ED1 exit rates thereby protecting customers from the risk of high forecasting.

There are no drawbacks identified to the mechanism, however this statement is based upon the working assumption that the revised RIIO-ED2 PCFM will allow for future use of the UM to be forecast to update allowed revenue as described in section 4.8. Without this functionality in place, due to the two-year time lag from AIP[37] and 15 months' notice for DUoS charge-setting, this could limit DNO ability to deliver due to the delay in cashflow from the time of the need of expenditure, resulting in a barrier to LCT uptake and would be a significant drawback of the mechanism.

8. Summary of proposal

Area	Our proposal
Mechanism type	Volume driver (annual) – annual volumes multiplied by unit cost
Unit cost	*Unlooping* [redacted] property with constraint resolved *Fuse/Cut-out* - [redacted] per property with constraint resolved *Service cable up-rate* - [redacted] per property with constraint resolved
Covering	Cost of removal of LCT constraint both direct and indirect costs
Regulatory reporting and evidence	Included in RRP and AIP (or equivalent in RIIO-ED2) frameworks

[37] Or equivalent in RIIO-ED2

Appendix C- Moorside – Nuclear development on the west coast of Cumbria

This appendix sets out our proposed changes to our existing bespoke uncertainty mechanism named ‘Moorside’ for RIIO-ED1 to ensure it is fit for purpose for application in the RIIO-ED2 period.

1 December 2021

Appendix C – Moorside – Nuclear development on the west coast of Cumbria

1. Executive Summary

An update to our existing bespoke uncertainty mechanism is needed given the changes around the timing and form of nuclear development on the west coast of Cumbria in RIIO-ED2. In RIIO-ED1, it was envisaged that a large single nuclear power station (assumed as 3.6GW) was the only development scenario that was needed to be covered by the Moorside uncertainty mechanism. In RIIO-ED2, this isn't the case with the advent and progression of more modular nuclear technologies supported by the UK Government and private enterprise. Small modular reactors (SMR) could impact on the type of connection and the solution needed to accommodate the nuclear development on our distribution network. Further, the trigger for accessing the Moorside uncertainty mechanism needs to be amended to cover SMR development and/or a large singular nuclear power station as this differs under the scenarios envisaged.

This document sets out the details behind these needed updates and reflects our proposals on what is needed to ensure that the Moorside mechanism in RIIO-ED1 is fit for purpose to cover the RIIO-ED2 period.

We have proposed the updates to the UM for Moorside for RIIO-ED2 based on the information and regulatory framework known at the time of drafting. Given that decisions from Ofgem are pending in relation to items that could impact the UM design for Moorside we suggest that we work with Ofgem between now and Final Determination to ensure a mechanism reflective of the final regulatory framework for RIIO-ED2 and the uncertainty of nuclear development on west coast of Cumbria is secured.

Potential areas of impact include, but are not limited to:

- The access and forward looking charging significant code review (SCR)
- Other reforms under SCR
- Changes to charging rules under the Connection and Use of Systems Code (CUSC)
- Final design and implementation of load related expenditure mechanism for RIIO-ED2
- Ofgem decision on high value projects criteria for RIIO-ED2
- Decisions on government support for nuclear development

We are open to working with Ofgem on the revisions to the mechanism '*CRC 3L. Arrangements for the recovery of Moorside Costs*' as proposed in this document between final business plan submission and final determination if required.

2. Introduction and Background

In our RIIO-ED1 licence, we have a bespoke mechanism to manage the impact of major changes required to our network should new nuclear generation connections take place near Sellafield in Cumbria. This is known as the 'Moorside condition' reflecting the likely geographical location of the development on the west coast of Cumbria.

At the time of submitting our well justified business plan for the RIIO-ED1 period [redacted] were proposing to build a new nuclear power station near to the existing nuclear reprocessing plant at Sellafield, Cumbria.

The development, that was uncertain to occur at the time of our RIIO-ED1 plans, was for a 3.6GW nuclear power station at Moorside near Sellafield with a NGET transmission connection. To enable this connection, National Grid would have needed to provide significant upgrades and new transmission circuits to its network. The reinforcement of the transmission network was assessed to have significant effects on our existing distribution network in Cumbria.

Additionally, at the time of RIIO-ED1 and as remains the case, there is insufficient capacity on our network to connect the large power station or alternatively the prospect of multiple small modular (nuclear) reactors (SMRs) in the region of the west coast of Cumbria. Rated at approximately 440MW each, SMRs whilst smaller than traditional large nuclear power stations, are still large units from a distribution network perspective, especially if multiple units are developed. Significant enabling works would be required if they are to be connected to either the distribution or transmission network in Cumbria.

In January [redacted] announced that it was suspending work on its nuclear new build projects, and the Office for Nuclear Regulation (ONR) resources that had been engaging with the company on its preparation of a nuclear site licence application were redeployed onto other regulatory work. As a result of this change, the existing RIIO-ED1 UM has not been used due to the development of the large nuclear power station being placed on hold.

In June 2020 [38], a group of companies, trades unions and individuals announced an initiative to develop a Clean Energy Hub [39] centred on a package of nuclear projects at Moorside. The proposal is based on projects including a new 3.2 GW UK EPR plant, as well as SMRs and advanced modular reactors (AMRs), with links to technologies including renewables and hydrogen production.

As a result of these developments in 2020 and the region's aspirations for clean energy development, in RIIO-ED2 there continues to be the potential for new nuclear generation to be developed in this area, which by its nature is large and complex, even if made up of one or more SMRs or the larger 3.6GW power station. Either scenario would necessitate major works on our network to facilitate it.

The type of development has potentially changed from that envisaged when the UM was originally drafted and developed for the RIIO-ED1 period. We have set out what these changes are in detail in section 3 of this Appendix but, for brevity and ease of reference, the nuclear development in West Cumbria could be SMR(s) nuclear technology (approximately 440MW per SMR) rather than the envisaged single large nuclear power station (assumed 3.6GW as per ED1) as was the case in RIIO-ED1. This does not mean that the development could not be a single large nuclear power station, and as such this bespoke UM needs to cover both potential development scenarios.

However, as in RIIO- ED1, this is not certain to be required in the period of RIIO-ED2, so we have not included any baseline (ex-ante) allowances in our final business plan (FBP) and instead propose a continuation of a bespoke uncertainty mechanism (our RIIO-ED1 Moorside condition - CRC 3L) with some changes/reforms needed to ensure that it is fit for purpose for the RIIO-ED2 period.

We will continue to work with Ofgem to update the uncertainty mechanism, so it best reflects the circumstances and uncertainty for RIIO-ED2 between now and final determination, based on the proposals set out in this document.

[38] https://www.onr.org.uk/civil-nuclear-reactors/moorside.htm

[39] https://www.edfenergy.com/energy/nuclear-new-build-projects/sizewell-c/news-views/edf-joins-major-companies-unions-to-promote-moorside-clean-energy-hub

3. Statement of need for RIIO-ED2

Nuclear development on the west coast of Cumbria is still likely though the timing of such development remains uncertain. Additionally, and in contrast to RIIO-ED1, the type and form of nuclear development is also now more uncertain, though regardless of type and form there is a significant and material impact on our network including the costs likely to be incurred to facilitate nuclear development on the west coast of Cumbria. A continuation and revision of the re-opener mechanism for ED2 ensures the best protection for consumers and risk balance given we are not proposing any baseline allowances for this activity and costs will only be needed and asked for should the need arise in period. Additionally, we have discussed with the ESO and TO at a high level our proposals in this document which include ensuring that North West distribution customers don't incur costs for facilitating a transmission or national requirement which should be recovered via all customers.

3.1. Evidence on potential nuclear development in RIIO-ED2 period

3.1.1 Cumbria Local Enterprise Partnership (CLEP)

In August 2020, on behalf of the Clean Energy Sector Panel of the Cumbria Local Enterprise Partnership (CLEP)[40], the 'Cumbria: Nuclear Prospectus – Energising the Energy Coast' was published[41]. The prospectus set out the "*ambition for the growth of a Cumbrian energy cluster, with nuclear as the key component of a low carbon, clean growth economy*"[42].

This document states that "*Development of the Moorside site is of strategic national importance: a large nuclear station here could meet 7% of UK's or 6 million homes, creating 21,000 jobs over its operational lifetime. We must plan for the future beyond current large scale nuclear technologies, by investing in the development and deployment of Small and Advanced Modular reactors. Cumbria has the sites and capability to deliver advanced nuclear for the UK.*"[43]

We have a strong working relationship with CLEP and have been engaging with them to inform their ambitions and plans for the west coast of Cumbria through regular dialogue, bilaterals and other engagement opportunities.

It is clear from the nuclear prospectus and through our engagement with the CLEP that nuclear development on the west coast of Cumbria is likely and that both SMR and a large nuclear power station are being explored for development over the long term. Ensuring that we are not a blocker to these aspirations is key, and a cornerstone of this is ensuring that adequate funding and cost recovery can be accessed as and when the need arises.

3.1.2 Moorside clean energy hub[44]

The Moorside Clean Energy Hub is a vision for a new integrated project which aims to help support the delivery of a low carbon energy future.

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[40] Clean Energy Sector Panel of the Cumbria Local Enterprise Partnership (CLEP) is a partnership body that is committed to developing clean energy opportunities to meet the UK's commitment to achieve Net Zero by 2050.
[41] Cumbria: Nuclear Prospectus – Energising the Energy Coast, CLEP, August 2020
[42] Ibid.
[43] Ibid.
[44] https://www.moorsidecleanenergyhub.com/

A consortium of leading UK construction, engineering and nuclear specialists, along with trade unions, has come together to explore low-carbon potential by promoting a Clean Energy Hub in the North West, specifically the west coast of Cumbria.

At a high level, The Moorside Clean Energy Hub is exploring:

- developing a new nuclear project with twin UK European Pressurised Reactor (EPRs), replicating Hinkley Point C's approved design, utilising an experienced project development and supply chain
- hosting small modular reactors (SMRs) and advanced modular reactors (AMRs)
- creating linkages with emerging technologies, such as green hydrogen and energy storage

3.1.3 Government policy

UK research and Innovation (UKRI) and the Low-Cost Nuclear Challenge, proposed by a consortium led by [redacted] are aiming to develop SMR design and manufacture in the UK capable of producing cost effective electricity. Initially £36m of joint public and private investment was granted in 2019 enabling the consortium to enhance and develop the design of SMR.

All this is in aid of supporting the UK Government's aspirations and policy on advancing nuclear development as set out in 'The Ten Point Plan'[45] and the 'Energy White Paper'[46]. These both stated the Government's intention to deploy a First-of-a-Kind SMR by the early 2030s, with up to £215m committed through the Advanced Nuclear Fund of £385m. Should a first of a kind SMR be deployed by the early 2030s then we would expect work to commence during the second half of RIIO-ED2 should distribution network developments be needed in our area.

Additionally, up to an additional £40m has been stated by Government for developing regulatory frameworks and supporting UK supply chains to progress work on key policy and market enablers, including finalising regulatory access, siting, and financing for SMRs.

Ultimately, *"The UK government believes that Small Modular Reactors (SMRs) could play an important role alongside large nuclear as a low-carbon energy source to support a secure, affordable decarbonised energy system."*[47]

Finally, the Government also sees that nuclear development in Cumbria remains with Moorside a potentially suitable site identified in the Government's nuclear national policy statement.[48] Separately as part of the Autumn budget and Treasury spending review the Government set out to "provide up to £1.7 billion of new direct government funding to enable a final investment decision in a large-scale nuclear project this Parliament"[49].

3.2. Impact of development in ED2 period

The potential development of a nuclear power station at Moorside in RIIO-ED1 was based on a single large nuclear power station on the west coast of Cumbria. Due to its large capacity, the impact on our distribution network in Cumbria was expected and accepted to be as a consequence of significant transmission network reinforcement requirements and new transmission circuits providing the

[45] The Ten Point Plan for a Green Industrial Revolution, HM Government, November 2020
[46] ENERGY WHITE PAPER Powering our Net Zero Future, HM Government, December 2020
[47] https://www.gov.uk/government/publications/advanced-nuclear-technologies/advanced-nuclear-technologies
[48] https://www.gov.uk/government/collections/nuclear-power-moorside
[49] Autumn budget and spending review, October 2021

necessary capacity. This would still have a significant impact on our distribution network in Cumbria if a large power station goes ahead.

Additionally, at the time of RIIO-ED1 development, and still the case now, there is insufficient capacity at Sellafield on our network to connect the large Moorside power station or alternatively the prospect of SMR(s) on the west coast of Cumbria.

The latter approach of a single SMR could potentially be accommodated by a distribution network solution led by ourselves, whereas it remains our view that a large Moorside power station certainly or potentially multiple SMRs would likely need a transmission solution. However, any transmission network solution would be expected to have marked and material impacts on our distribution network.

Given that the proposed development of nuclear technology on the west coast of Cumbria is uncertain, i.e. whether large nuclear development will be deployed (as envisaged at RIIO-ED1) or smaller modular reactors (SMR), the impact could be different, though significant and material to ENWL under all scenarios envisaged.

Though the impact on our network will differ under a SMR or single large nuclear power station development, the consequence under both is significant and material to our network and the ring main around Cumbria due to the location of development. A single SMR may be accommodated on our network by increasing the rating of existing circuits. However, multiple SMRs or a large power station would require transmission circuits operating at higher voltages, potentially using the routes of our existing circuits meaning that our network would need major reconfiguration.

Because there are multiple scenarios that can occur for Moorside nuclear development we need to amend the uncertainty mechanism to cover the costs incurred under all potential situations. As drafted for RIIO-ED1 currently this isn't the case. As specific example of this would be the trigger for the uncertainty mechanism which would differ under different nuclear development scenarios. We set out our proposal for trigger in figure 3.3 and section 4 below.

3.3. Interaction between other RIIO-ED2 uncertainty mechanisms

The existing licence condition for RIIO-ED1 covering a Moorside development already includes drafting to ensure that costs recovered from other uncertainty or regulatory mechanisms aren't also provided for by CRC 3L ('Arrangements for the recovery of Moorside Costs'). We support this and propose that this remains for an updated RIIO-ED2 licence condition and UM covering nuclear development on the west coast of Cumbria.

We do want to be clear though on why a licence condition specifically covering the Moorside development is important and also how we propose that it interacts with other uncertainty mechanisms to fully cover the material cost impact on ENWL of such development occurring in the RIIO-ED2 period.

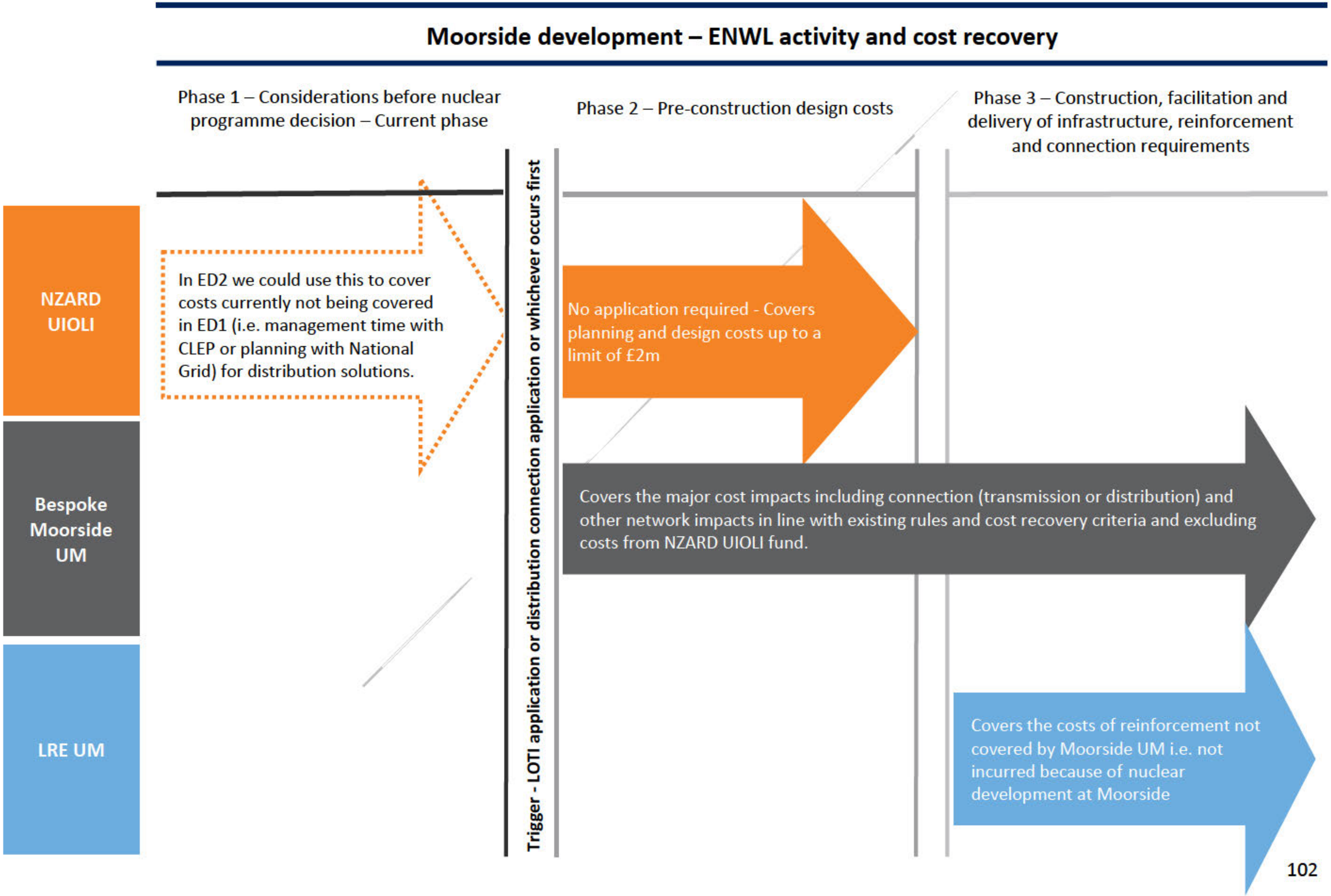
In figure 3.3 below we have set out that we believe some interaction between the following uncertainty mechanisms is likely, and also how we see the uncertainty mechanisms working cohesively whilst ensuring only the full efficient costs incurred are able to be recovered. The uncertainty mechanisms that potentially interact with our revised and updated Moorside uncertainty mechanism in RIIO-ED2 are:

- **Net Zero and Re-opener Development Fund (NZARD)**: In RIIO-ED2, we are proposing that part of this use-it-or-lose-it (UIOLI) fund could be utilised to cover costs associated with considerations before a nuclear programme decision has been reached. Broadly speaking this is the current phase we are in and would mean appropriate support to CLEP and other stakeholders could be given with the aim of supporting it in its aspirations to realise new nuclear development on the west coast of Cumbria. We note that whilst the application of NZARD to RIIO-ED2 hasn't been determined yet, we are proposing this as part of managing uncertainty in RIIO-ED2 (see section 4.6 for full details on our NZARD proposals). Should the outcome be a transmission solution then we'd expect the transmission solution provider to fund our costs so that the costs of transmission are recovered from transmission customers.

- In addition to engagement with the bodies involved in nuclear development, there will likely be preliminary network studies and assessments required ahead of final plans. The NZARD can provide funding for the essential initial investigatory works to allow us to put together a robust and detailed application for the Moorside UM re-opener.

- **Load related expenditure (LRE) mechanism for RIIO-ED2**: Nuclear development on the west coast of Cumbria at the scale of between 440MW and 3.6GW plus will have an impact on our LRE in RIIO-ED2. We view that costs incurred because of Moorside nuclear development should be allocated and recovered through our bespoke Moorside UM (as currently envisaged) with the common LRE mechanism covering the costs of reinforcement not associated with the connection of nuclear power and not covered by the Moorside UM.
    - The LRE UM is not considered suitable for developing our network to accommodate new nuclear generation in Cumbria because the drivers for the necessary work are likely to extend beyond network reinforcement. Investment is likely to be required for activities which lie outside of load works, in particular diversion and other enabling works to reconfigure our network necessary due to the impact of transmission network works. For full details on our proposals for LRE treatment in RIIO-ED2 please see Appendix A.

Figure 3.3: Interaction of proposed RIIO-ED2 uncertainty mechanisms and our bespoke Moorside mechanism



4. Proposed changes for RIIO-ED2

Given the statement of need in section 3, we are proposing that the uncertainty mechanism 'CRC 3L. Arrangements for the recovery of Moorside Costs' continues for the period of RIIO-ED2. That said, for this mechanism to be fit for purpose for the upcoming regulatory period, some targeted changes and reforms need to be made to reflect the uncertainties and the current knowledge of the types of form of nuclear development being considered on the west coast of Cumbria. We have set these out below:

- **Name** – Moorside can and is proposed to remain as the name of the development, but this is proposed to refer to, and allow for, nuclear development(s) on the west coast of Cumbria reflecting the stated aspirations of the CLEP and the scenario where multiple SMRs are developed. This impacts areas:
    - Part E: 3L.39 of the existing licence condition namely 'Moorside' definition with removal of reference to "station" singular.
- **Type of development** – Given that the type and scale of nuclear developments on the west coast of Cumbria is uncertain, it is proposed that the references to Transmission system relating to costs, connections, agreed project are changed to reflect the fact that these aren't applicable under all scenarios such as a distribution connection. This reflects the difference in project/connection where an SMR(s) are deployed but also reflecting the option that a large singular nuclear power station development could occur. This impacts areas:
    - Introduction: 3L.1(d), 3L.4(c)
    - Part B: 3L.8 (c), (d), (e), 3L.10 (c), (c)(ii), 3L.12 (b)
    - Part C: 3L.24 (b)
    - part E: 3L.39 specifically definitions of "Moorside", "Moorside connection project" to include scenario of distribution connection, "Moorside detailed project assessment", "Moorside Options", "Moorside costs", "SWW Determination", and definition of "Charges to the Transmission Licensee"
    - All of the above in relation to the existing licence condition.
- **Trigger for application** – currently the trigger for submission to Ofgem of an adjustment for Moorside Costs is defined by "Moorside Detailed Project assessment" which links to strategic wider works (SWW) determination by Ofgem under the transmission licence. Given the links to Ofgem determination under SWW is not planned for continuation in RIIO-T2, and because this won't be the appropriate trigger under all envisaged scenarios (i.e. a distribution connection for SMR development), we suggest that a definition and appropriate trigger is agreed between Ofgem and ENWL that supports development under SMR and/or large nuclear power station on the west coast of Cumbria. We propose this is linked to a LOTI application at an early stage such as initial need case, or distribution connection application or whichever occurs first in the period. This would cover all envisaged development scenarios and ensure timely triggering of the UM can occur. This impacts areas
    - Part B: 3L.7 and referenced paragraphs contained therein, 3L.9, 3L.10, 3L.11, 3L.12
    - part E: 3L.39 specifically definitions of "Moorside connection project" to include scenario of distribution connection, "Moorside detailed project assessment", "Moorside Options", "Moorside costs", and "SWW Determination"
- **Out of date RIIO-ED1 references** – Additional to the references to SWW, above we propose that references that are no longer applicable to RIIO-ED2 are updated. This is not limited to; Network Asset Secondary Deliverables (NASD), period of 2015/16 to 2022/23, ED1, 1 April 2015 and price base etc. Updated references are required to change:

- “Network Asset Secondary Deliverables” to “Network Asset Risk Metric [NARM]”
- “2015/16 to 2022/23” to “2023/24 to 2027/28”
- “ED1” to “ED2”
- “1 April 2015” to “1 April 2023”
- “2012/13 prices” to “2021/22 prices”

We are keen to discuss all the changes required including any which Ofgem consider necessary as part of continued engagement with Ofgem between final business plan submission and final determination of our business plan.

5. Assumptions and caveats for uncertainty mechanism design

We have proposed the updates to the uncertainty mechanism for Moorside for RIIO-ED2 based on the information and regulatory framework known at the time of drafting. Given that decisions from Ofgem are pending in items that could impact the uncertainty mechanism design for Moorside, we suggest that we work with Ofgem between now and Final Determination to ensure a mechanism reflective of the final regulatory framework for RIIO-ED2 and the uncertainty of nuclear development on west coast of Cumbria is secured.

Potential areas of impact include, but are not limited to:

- The access and forward looking charging significant code review (SCR)
- Other reforms under SCR
- Changes to charging rules under CUSC
- Final design and implementation of load related expenditure mechanism for RIIO-ED2
- Ofgem decision on high value projects criteria for RIIO-ED2

We have also held preliminary discussions with National Grid TO and the ESO with regard to our updated uncertainty mechanism for RIIO-ED2 and specifically considering the process under a transmission led solution. Our discussions covering whole system considerations has set out the importance of understanding cost recovery and the process by which this is managed under a transmission solution scenario. There are various options available with the generator, TO and ESO all key parties in ensuring that distribution customers do not incur costs of facilitating a transmission led solution under this scenario. We will continue to work with Ofgem and all key stakeholders to ensure a suitable solution is agreed which also considers who provides any funding indemnity, ensuring the risk profile is fairly calibrated between TO, ESO, third-party generator, and consumers.