Scottish & Southern Electricity Networks

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Regulatory Framework Uncertainty Mechanisms

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Scottish Hydro Electric Transmission plc

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1 Uncertainty Mechanisms - developing efficient responses to risk

1.1 We have built our Business Plan base allowances on the Certain View because we are able to identify the need, justify the solution or option proposed and forecast the cost with certainty. In doing so, consumers can have confidence that the activity is necessary, and the cost is efficient.

1.2 Our Certain View investment amounts to £2.4 billion and includes:

- growth related capital expenditure where we have high certainty of new renewable generation proceeding e.g. Electricity System Operator (ESO) driven schemes, schemes that cross over from the RIIO-T1 price control into RIIO-T2;
- asset-driven capital expenditure covering major scheme replacements and refurbishment based on condition;
- capital expenditure relating to maintaining network resilience;
- capital expenditure relating to IT system upgrades; and
- operational costs covering a wide range of aspects such as asset inspection and maintenance activities, business support costs, control room, network planning etc.

1.3 Beyond the Certain View, the need for investment is driven by external influences or the justification of the adopted solution is contingent on factors outside our control. It is then not possible to forecast the future cost requirements with the requisite certainty prior to the start of the price control.

1.4 Basing our Business Plan proposals on scenarios where the need is not clearly established can pose a material risk to both consumers and companies. Either base allowances are included which may transpire not to be required (a windfall to the network company) or no allowance is included, and the investment need materialises (a material risk to the network company's returns and delivery of consumer outputs). A good price control would wish to avoid both these outcomes.

1.5 Uncertainty mechanisms provide the solution to managing many of the events outside our control. Such mechanisms allow for controlled changes to our allowed revenues to be made during the price control once the uncertainty has reduced. This ensures that consumers only pay for necessary investment and for the outputs that are delivered.

1.6 Stakeholders have consistently told us that managing uncertainty is a key priority for them. This view was strongly reinforced when we consulted on our draft Business Plan. We have been careful to identify uncertain cost activities and propose appropriate mechanisms to manage this uncertainty, balancing our risk and that of consumers (see Figure 1.1).

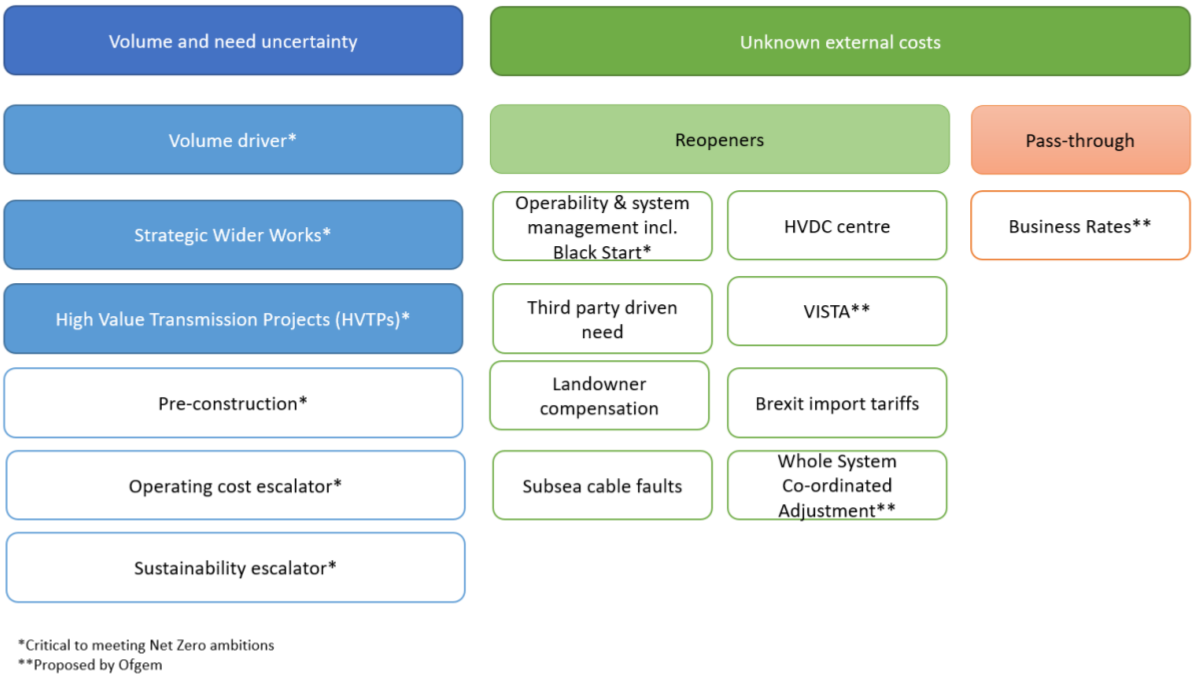
1.7 Our proposed approach to uncertainty ensures upfront funding is only for known need, known costs and known outputs; consumers are not at risk of funding outputs that might not happen. This protects consumers from uncertain costs and avoids the complicated clawback of funding that has not been used.

1.8 Our uncertainty mechanisms fall into two broad categories:

- **volume and need uncertainty:** where *volume* is primarily timing, location and scale uncertainty about future energy flows on the transmission system, in particular of renewable generators. *Need* relates to uncertainty about the timing and scale of making a known investment (for example the Eastern HVDC link); and
- **unknown external costs**: where we are required to do something required by a third party, for example by the ESO or Government, or because of a high impact event, such as a subsea cable fault.

1.9 Overall, we have identified 15 uncertainty mechanisms which are described in the following pages. Ofgem has also proposed other finance mechanisms (Cost of Debt, Cost of Equity, RAV indexation, tax liability, pensions). These are not considered in this Supporting Document.

Figure 1.1 RIIO-T2 Proposed Uncertainty Mechanisms



1.10 The above proposals account for known unknowns. It is also important that Ofgem and the regulatory framework recognise that there are "unknown unknowns". We are in a period of energy system transition and significant political uncertainty, notably with Brexit, but also because the possibility of Scottish Independence remains. This could have major implications for the energy sector as energy policy in Scotland is currently reserved to the UK Parliament. The end of RIIO-T2 is over six years away and a lot can change in the intervening period. The regulatory framework must and should be capable of responding, without having to wait for the next price control period. If not, then this could present an artificial boundary, as we seek to respond to the economic and environmental challenges and opportunities of the energy system transition.

1.11 Ofgem in its Business Plan Guidance[1] requires that for each uncertainty mechanism we provide detail against nine headings:

a) Issues and risks the mechanism addresses;

b) Ownership of the risks;

c) The proposed mechanism;

d) Justification for the mechanism;

e) Materiality of the issue;

f) Frequency and probability of the issue;

g) Drawbacks of proposed mechanism and mitigation;

h) Value for money and ability to finance; and

i) Treatment in business plan data tables (BPDTs).

1.1.1 We use these as sub-headings for each of the proposed uncertainty mechanisms in this paper, except for "Treatment in BPDTs". All of our costs and volumes associated with the uncertainty mechanisms will be reported under Table 5.18 "bespoke_uncertain". Discussions with Ofgem and the other transmission operators (TOs) with recommence in next year to refine the BPDT reporting requirements. If we have any baseline funding for the associated uncertainty mechanism, we report this in the Outputs, Uncertainty Mechanisms and CVP Snapshot Tables Ofgem request (see Appendix 1).

[1] https://www.ofgem.gov.uk/system/files/docs/2019/10/riio-2_business_plans_guidance_october_2019.pdf

2 Volume and Need Uncertainty

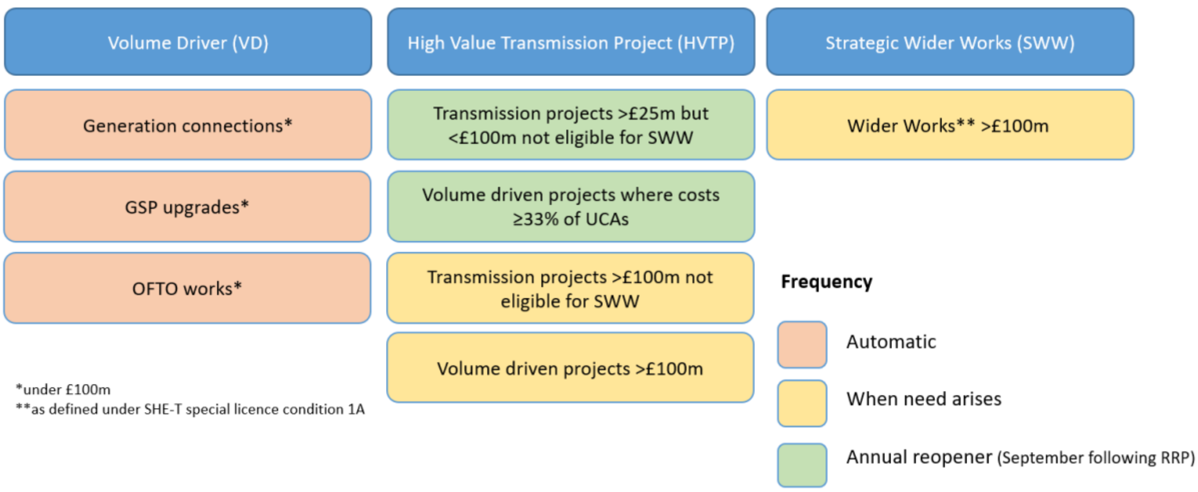
2.1 Some expenditure which will be incurred in RIIO-T2 to meet new generation and demand network requirements is certain. These are projects that are already known and under development. Forecast costs are therefore included in our Certain View. However, while a number of significant connections appear committed, experience from RIIO-T1 indicates that the scale and timing of connections will change and additional projects will emerge as reinforcements are sanctioned.

2.2 As we look later in the RIIO-T2 period, we either cannot identify particular projects or projects are ill-defined at this stage. The actual level of capacity required is very sensitive to external factors such as economic growth, the response of generators to the energy market and the speed of electrification of heat and transport, as set out in our Planning for Net Zero Scenarios paper[2]. We see this clearly in the possible ranges in our North of Scotland Scenarios and the Electricity System Operator's Future Energy Scenarios (ESO FES).

2.3 We propose that these less certain costs are accommodated under a volume driver, Strategic Wider Works (SWW) mechanism and High Value Transmission Projects (HVTP) reopener.

2.4 Importantly we propose that these mechanisms will be for future submissions to Ofgem and not for in-flight regulatory processes, that is the three island needs cases – Orkney, Western Isles and Shetland. These will remain subject to the current RIIO-T1 SWW mechanism.

Figure 2.1 RIIO-T2 Proposed mechanisms for volume and need uncertainty



[2] SUPPORTING DOCUMENT 3: Planning for Net Zero: Scenarios, Certain View and Likely Outturn, found here: https://www.ssen-transmission.co.uk/riio-t2-plan/planning-for-net-zero-scenarios-certain-view-and-likely-outturn/

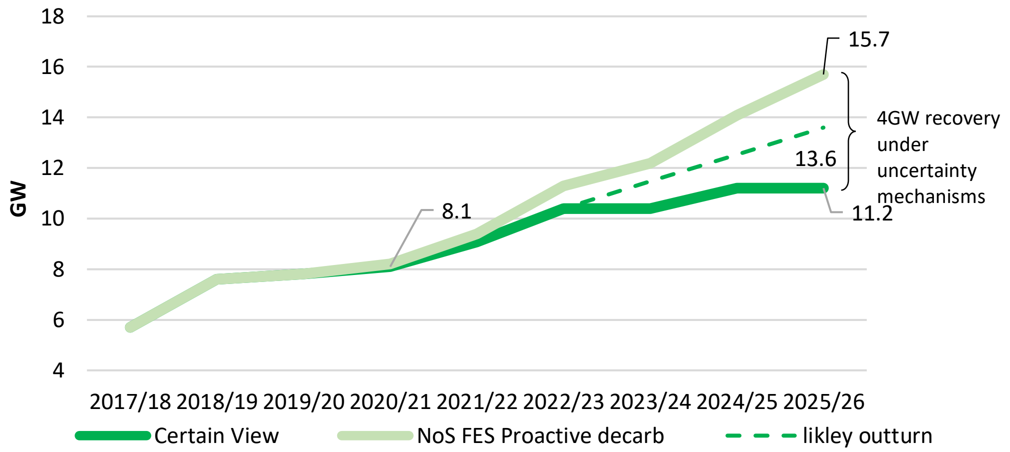
2.1 Volume Drivers

Introduction

2.1.1 As the Transmission Owner (TO) in the North of Scotland, we have a legal obligation to facilitate the connection of new generation customers to our network and we must ensure our network is capable of meeting demand requirements. Some expenditure which will be incurred in RIIO-T2 to meet new generation and demand network requirements is certain. There are projects that are already known and under development; engineering solutions and forecast costs are therefore included in our Certain View, as discussed above. However, while several significant connections beyond the Certain View appear committed, experience from RIIO-T1 indicates that the scale (and therefore engineering solution) and timing of connections will change, and additional projects will emerge. They are very sensitive to external factors outside of our control.

2.1.2 Considering renewable generation alone, under the Certain View, the total renewable generation connected to the north of Scotland transmission system will reach nearly 10 GW by March 2026 (total generation 11.2GW.) As outlined in our Planning for Net Zero Scenarios paper[3] our assessment of future energy scenarios shows there is the potential for generation connections to exceed our Certain View by 4 GW or more. This paper also details our Likely Outturn view, which is our assessment of currently uncertain generation connections to exceed the Certain View by around 2.4 GW. The makeup and timing of generation connections over-and-above the Certain View is highly uncertain.

Figure 2.2 Total generation capacity connected to the north of Scotland transmission network through RIIO-T1 and forecasted connections for RIIO-T2



2.1.3 As experienced in RIIO-T1, we fully expect currently uncertain generation connection investments to gain certainty during the RIIO-T2 period. We successfully used a suite of flexible funding mechanisms in RIIO-

[3] SUPPORTING DOCUMENT 3: Planning for Net Zero: Scenarios, Certain View and Likely Outturn, found here: https://www.ssen-transmission.co.uk/riio-t2-plan/planning-for-net-zero-scenarios-certain-view-and-likely-outturn/

T1, including a volume driver for generation connections[4] and we believe a similar approach, building upon key lessons from RIIO-T1, should be applied in RIIO-T2.

2.1.4 This section outlines our proposals for the RIIO-T2 volume driver for both generation and demand connections, outlining how we have updated our approach to ensure it allows for the scope of network solutions we will be required to deliver in RIIO-T2 and deliver improved cost reflectivity for the consumer; that is that the cost incurred will be more reflective of the outputs delivered, a key priority for RIIO-2.

2.1.5 The RIIO-T2 volume driver is intended to cover schemes that will connect from 2023/24 onwards. Generation schemes connecting in the first two years of the RIIO-T2 period will be recovered under the existing RIIO-T1 volume driver[5] and form part of our Certain View.

a) Issues and risks the mechanism addresses

2.1.6 The RIIO-T2 volume driver builds on an established process we applied in RIIO-T1. The two key issues addressed by the mechanism are:

- it allows us to respond quickly and flexibly to the changing energy market and the volume, type and scope of generation and demand connections to meet the net zero challenge; and
- it ensures consumer value by avoiding burdening consumers with anticipatory investment as costs for local enabling works will materialise as and when required and not before.

Responding to change

2.1.7 Figures 2.3 and 2.4 show that throughout RIIO-T1 we experienced significant changes to the levels and types of generation connecting to our network. We enabled 2.2 GW of new onshore wind to connect, an increase of over 120%. There were also rapid increases in the connection of offshore wind.

2.1.8 A high degree of change and variability of connection schemes, and associated configurations was also experienced in RIIO-T1; including significant deviations from original schemes used to define our RIIO-T1 ex ante baseline allowance to set shared and sole use infrastructure. **Less than a third of the identified RIIO-T1 schemes that were predicted went ahead.** Instead, different schemes proceeded in the period.

2.1.9 Our proposed RIIO-T2 volume driver mechanism builds on the established and successful processes in RIIO-T1 but makes improvements to build in efficiencies and ensure outputs delivered are most reflective of the costs incurred; a key priority of the RIIO-2 price control.

Figure 2.3 RIIO-T1 generation breakdown

[4] Special Condition 6F, Baseline Generation Connection Outputs and Generation Connections Volume Driver mechanism license condition.
[5] We detail this is a T1/T2 Crossover paper submitted to Ofgem.

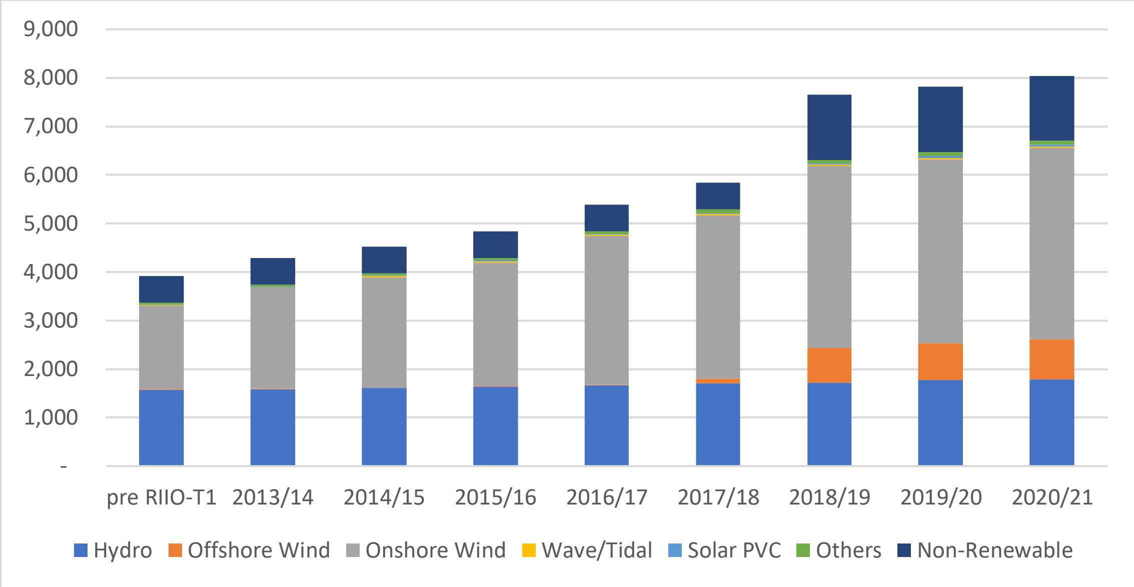
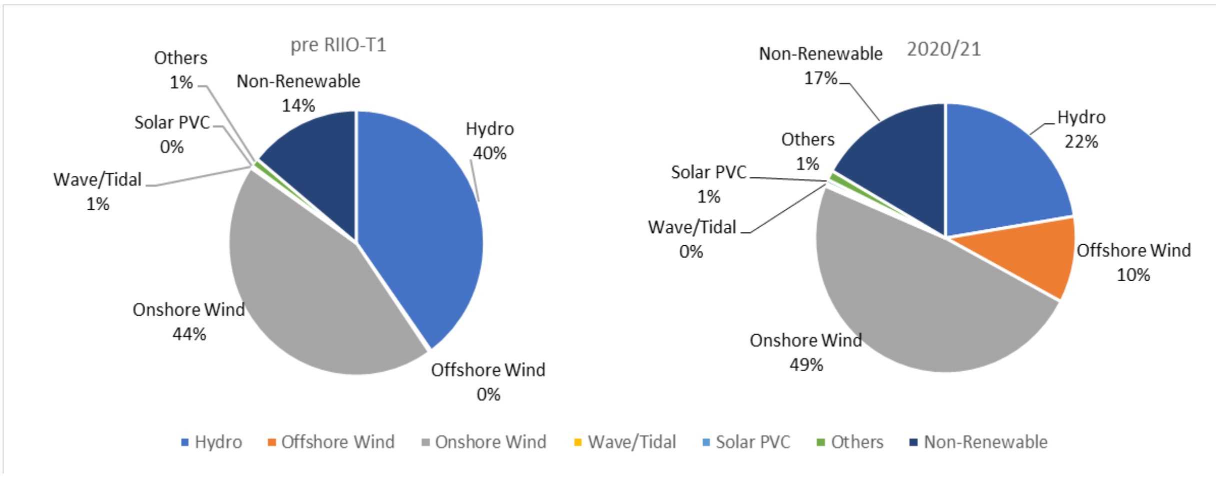


Figure 2.4 Generation types pre RIIO-T1 compared to forecasted 2020/21



Ensuring consumer value

2.1.10 The volume driver protects consumers against inaccurate forecasting of investment and ensures timely connection of new generation to the network as it provides us with the flexibility to react to new connection requests as and when they arise. The alternative funding mechanism would be through a fixed allowance which carries significant risks:

- consumers, and the generation customer connecting, pay more than they need to if a smaller volume of work is needed; and
- could result in us not having the funding to provide connections when we are legally required to do so.

2.1.11 Our proposal is therefore for a recovery mechanism that can be used to determine revenues for projects delivered over and above our Certain View. This mechanism will provide protection for consumers, and ensures we receive the revenue to cover the inevitable costs of additional efficient works to connect generation over and above our Certain View.

b) Ownership of the risks

2.1.12 The volume driver is in place to minimise the risk on both the consumer and the network company. It protects the consumer from both over-investment and under delivery by only providing allowances when the need arises, and protects the company from financial distress by ensuring revenues are adjusted in line with investments made.

2.1.13 It removes the risk entirely regarding need, as only when the need materialises will revenues be adjusted and importantly, those revenues are output dependent. Consumers therefore only pay for outputs delivered. This is a fundamental principle of our RIIO-2 plan.

2.1.14 The risk that does remain is one that applies in any ex ante regulation; that the actual costs (in this case the unit cost allowances (UCAs) for particular works) are different to the allowed UCAs set at the beginning of the price control. Nevertheless, it is important to set these at the start of the price control for two key reasons:

- it provides us with the ability to respond quickly and with confidence to changes in infrastructure investment required due to changes in generation or demand connections in order to meet net zero ambitions; and
- it sets an incentive to outperform the UCAs, i.e. to find efficiency savings, which will benefit consumers.

2.1.15 The balance of that risk will depend where Ofgem set the Totex Incentive Mechanism (TIM) sharing factor (i.e. if a 50/50 sharing factor is applied, the risk of any over or underspend will be shared equally between us and consumers).

2.1.16 We believe we have reduced the risk of consumers paying more than what is efficient for RIIO-T2 volume driver projects by basing our approach substantively on historical costs. This means our RIIO-T2 UCA rates have built-in embedded efficiencies. Therefore, consumers can be confident that the rate set is efficient and if we were to outperform that rate it will be due to finding further innovations in RIIO-T2, driving down costs further for RIIO-T3. This is why our volume driver approach forms part of our Consumer Value Proposition (CVP) as set out in our Outputs, Incentives, Consumer Value Proposition & Innovation paper[6].

[6] SUPPORTING DOCUMENT 12A: Regulatory Framework - Outputs, Incentives, Consumer Value Proposition & Innovation https://www.ssen-transmission.co.uk/riio-t2-plan/regulatory-framework-outputs-incentives-and-innovation/

c) The proposed mechanism

2.1.17 The volume driver mechanism sets ex ante UCAs for specific types of work that are typically incurred when we are required to make load related investment. When the work is undertaken our allowances will be adjusted in line with the UCA for each “unit” or volume of work delivered.

Volume driver infrastructure assets

2.1.18 The mechanism would apply to load related investment - infrastructure necessary to accommodate the connection of new generation and changes in demand characteristics.

2.1.19 Under the Connections Use of System Charging (CUSC)[7], which is the contractual framework for connection to, and use of, the National Electricity Transmission System (NETS), most of the costs for connecting new generators is borne by the TO (and ultimately consumers). Typically, connection infrastructure assets can be split into three categories – Transmission Connection Assets (TCA), Transmission Connection Asset Works (Sole Use) and Enabling Works (Shared Use). Table 2.1 provides full descriptions of each of infrastructure asset category.

Table 2.1 Transmission connection asset types

Infrastructure asset category	Description	Proposed RIIO-T2 recovery mechanism
Transmission Connection Assets (TCA)	The Transmission Plant and Transmission Apparatus necessary to connect the User's Equipment to the National Electricity Transmission System at any Connection Site in respect of which The Company charges Connection Charges (if any) as listed or identified in Appendix A to the Bilateral Connection Agreement relating to each such Connection Site *(as defined in the CUSC).*	Costs recovered directly from connection customer
Sole-use Generation Connections	Means the cumulative generation capacity in megawatts (MW) of transmission infrastructure works associated with the connection of new or additional generation from a single generating station to a part of the licensee’s Transmission System (or connected to a distribution system which in turn connects to a part of the licensee’s Transmission System) as specified in relevant agreements between the licensee and the System Operator pursuant to the System Operator Transmission Owner Code (STC)[8]. *(As defined in Scottish Hydro Electric Transmission Plc Electricity transmission licence Special Conditions).*	Volume driver
Shared-use Generation Connections	Means the cumulative system capacity of transmission infrastructure works in megavolt amperes (MVA) associated with the connection of more than one new or additional generating station to a part of the licensee’s Transmission System (or connected to a distribution system which in turn connects to a part of the licensee’s Transmission System) as	Volume driver

[7] https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc
[8] https://www.nationalgrideso.com/codes/system-operator-transmission-owner-code

	specified in relevant agreements between the licensee and the System Operator pursuant to the STC. *(As defined in Scottish Hydro Electric Transmission Plc Electricity transmission licence Special Conditio*ns).	

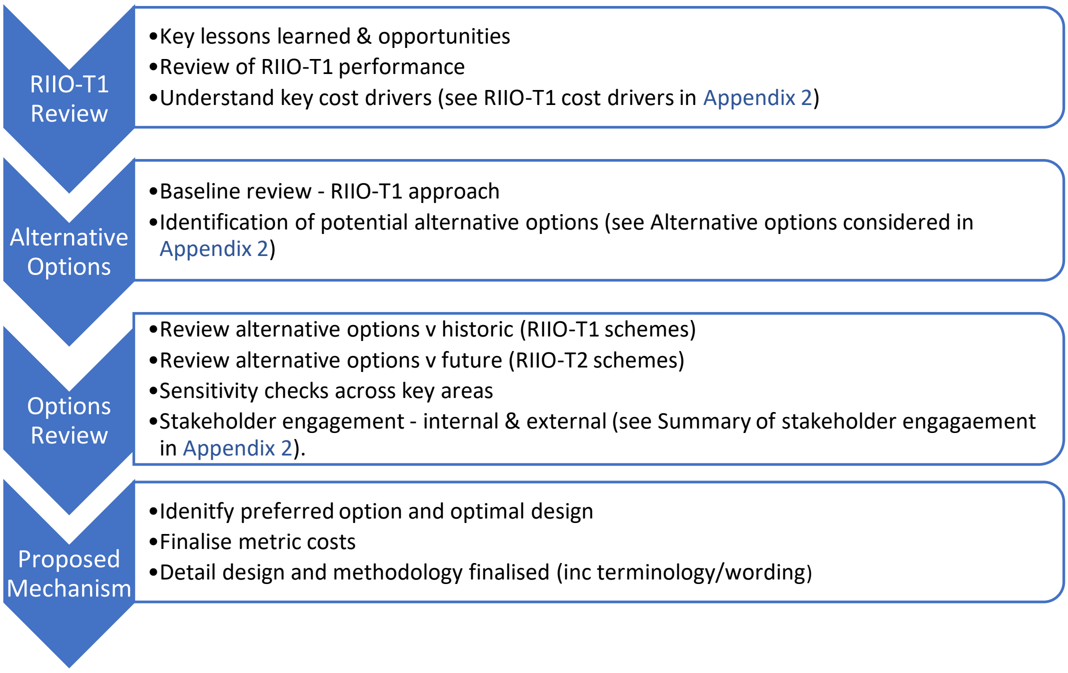
2.1.20 TCA, sole-use and shared-use infrastructure works will be triggered in most cases by changes in the following:

- traditional generation connections, which based upon on our view of contracted and scoping generation for the RIIO-T2 price control period is made up of **renewable connections** (i.e. onshore wind, solar, hydro, pumped storage, wave and tidal);
- offshore wind via the connection of new Offshore Transmission Operators (**OFTOs**);
- **Grid Supply Point (GSP) upgrades**, where works are typically triggered by both demand and generation connections. These projects have been treated as sole use in RIIO-T1, as even though multiple generators/demand schemes may trigger upgrades, we are delivering for one customer, the distribution network operator in the north of Scotland, Scottish Hydro Electric Power Distribution (SHEPD). The volume of GSP upgrades required will be largely dependent on economic growth and the speed of the electrification of heat and transport; and
- **demand schemes**, providing additional capacity at exit points on our network to meet increased demand.

Design of RIIO-T2 volume driver

2.1.21 Our approach to the design of the RIIO-T2 volume driver is summarised in the flow chart below, which highlights the four key stages in arriving at our proposal:

Figure 2.5 RIIO-T2 volume driver design process



2.1.22 **RIIO-T1 review:** Looking back over the application of the RIIO-T1 volume driver, although it proved to be a successful mechanism for recovering uncertain costs, the use of single aggregated UCAs for sole (£/MW) and shared use (£/MVA) led to large swings in recovery against allowances. In some cases, we experienced significant under/over performance. Such windfall gains and losses led us to question the cost reflectivity[9] of a an aggregated UCA approach. Also, the actual schemes delivered, especially OFTO and demand schemes, were significantly different to the scope set out in our baseline plan meaning large variances in spend against ex ante allowances in both categories. An objective in our approach for designing the RIIO-T2 volume mechanism was to have enough flexibility to accommodate uncertain OFTO and demand schemes as well as onshore generation schemes.

2.1.23 Considering this divergence in recovery for these scheme types, we carried out a broad review of all sole and shared use infrastructure delivered in RIIO-T1 under the volume driver. We confirmed that in the round, the scope of works for new sole use connections and shared use schemes involve the same elements and breakdown of works. Typically, sole and shared use schemes involve the following:

- **transformer substation** – installation of additional transformer capacity on our network, including all of the ancillary works associated with the installation (e.g. civil works, landing gantries, associated switchgear, protection etc);

[9] Maximising cost reflectivity, in our view, means designing an approach whereby the difference between the total allowance minus costs across a portfolio of projects is as close to zero as possible. Methods of measuring cost reflectivity include calculating the "error" (i.e. difference between total costs and total allowances; this should be as close to zero as possible), and carrying out regression analysis on allowances against cost, aiming for r^2 value close to 1 as possible.

- **switching station** – installation of new switchgear to accommodate new connections, including all of the ancillary works associated with the installation (e.g. civil works, landing gantries/tower modifications, protection etc); and
- **linear infrastructure** – overhead lines (new or reconductoring existing), underground cables, subsea cabling[10].

2.1.24 Our review of RIIO-T1 concluded that our approach in RIIO-T2 should:

- provide improved cost reflectivity; and
- consider a more disaggregated approach due to the similarities of scope, and the need for more appropriate mechanisms to accommodate OFTO and demand schemes.

2.1.25 **Alternative options:** In our design of the RIIO-T2 volume driver, we considered the continued application of single rates updated to reflect actual incurred costs to calculate the UCAs rather than forecast costs for RIIO-T2 schemes that we know will change in scope. To improve cost reflectivity, we also considered a more disaggregated approach i.e. using separate UCAs for different project elements. The alternative options considered during our design phase are summarised below:

1. **Option 1 -** High Level Aggregated approach, based on £/MW Sole Use and £/MVA shared use, as used during RIIO-T1;
2. **Option 2 –** Level 1 Disaggregated approach, based on a unit rate for linear infrastructure (i.e. overhead lines, underground cables and subsea cables) and £/MW (sole) and £/MVA (shared) for **all** other infrastructure (i.e. full substation infrastructure); and
3. **Option 3 –** Level 2 Disaggregated approach, based on a unit rate for linear infrastructure and unit rate recovery for different elements of the substation infrastructure (switching and transformer substation elements). Within this option we considered two variants:
    - **Option 3a)** based on a mix of £/MW and £bay costs for switching station elements
    - **Option 3b)** based on £bay costs for switching station elements.

2.1.26 **Options review and proposed mechanism:** After carrying out a thorough review of the alternative options, (for full summary of all options assessed and associated analysis, see Appendix 2) we concluded that applying a more disaggregated approach using separate UCAs for different project elements delivers improved cost reflectivity, whilst still catering for the large range of infrastructure categories and generation types. This was verified through extensive engagement with internal and external key stakeholders with detailed knowledge of the associated complexities of designing a wide reaching, reactive mechanism that caters for uncertainty.

[10] Although not used in RIIO-T1, could be required in RIIO-T2 pending approval of Island link schemes.

2.1.27 Table 2.2 shows the results of our cost reflectivity analysis for each of the options.

2.1.28 We have concluded Option 3b is the best approach as it delivers cost reflectivity, as seen through the comparatively lower windfall gains/losses via the min, max and average error terms in Table 2.2. This option also has high r^2 when comparing estimated allowances to actual/forecast costs for a selection of our RIIO-T2 likely outturn and contracted projects, alongside our estimated recovery on RIIO-T1. Our conclusion has been influenced by the following:

- Our analysis supports a move to a more disaggregated approach. We can clearly demonstrate that Level 2 disaggregated approaches (3a and 3b) provide a higher degree of cost reflectivity, leading us to discount Options 1 and 2 as credible options;
- For demand schemes and GSP upgrades, it provides a lower £/bay rate protecting consumers from over recovery. Additionally, in relation to OFTOs, whereby we could be connecting large MW generators for minimal bays works, this approach would allow reflective recovery of these costs via the £/bay rate.
- Option 3a has been discounted over 3b on the basis it is considerably more complex and would be more onerous to apply in the RIIO-T2 period, without commensurately greater benefit. This complexity relates to the reliance on arbitrary triggers for additional bay costs to cover additional switching infrastructure for atypical sole and shared use schemes.
- Overall, option 3b provides the most robust cost reflectivity when compared against certain sensitivities, a high degree of flexibility for a wide range of scheme scenarios and provides a robust platform to cover onshore and offshore generation as well as demand schemes. Finally, following extensive internal peer review and consultation it was deemed the most technically workable and practical approach. The bay recovery approach for switching infrastructure also reduces the potential for separate treatment for high value, atypical schemes as project element costs are more reflectively recovered via tailored UCAs.

Table 2.2 Volume driver option analysis results summary

RIIO T1 and T1/T2 crossover schemes	Option 1 (Aggregate Approach)	Option 2 (Level 1 disaggregation)	Option 3a (Level 2 disaggregation)	Option 3b (Level 2 disaggregation)
R^2 *(allowances compared to actual/ forecast costs)*	**0.646**	**0.618**	**0.840**	**0.838**
Min error £m	-48	-105	-42	-41
Max error £m	59	32	37	37
Average error £m	-3	-2	0	0
Error £m (% of total expenditure)	**-109 (-12%)**	**-91 (-10%)**	**-2 (0%)**	**16 (1%)**
RIIO-T1, T1/T2 crossover and RIIO-T2 schemes				
R^2 *(allowances compared to actual/ forecast costs)*	**0.592**	**0.666**	**0.833**	**0.821**
Min error £m	-48	-105	-42	-41
Max error £m	59	33	37	37
Average error £m	0	0	1	2
Error £m (% of total expenditure)	**10 (1%)**	**4 (0%)**	**88 (6%)**	**137 (10%)**

Equation	£/Bay + £/MVA + £/cct km OHL, UGC, Sub Sea
£/bay element	Covers costs associated with connection switchgear substation related elements, whereby the proposed recovery rates for £/bay would be for different voltages as below. To protect consumers against over recovery for schemes where the infrastructure scope involves direct replacement of existing switchgear without the need for additional ancillary works, a separate £/bay rate has been established for these scheme types. • 132kv £/bay - **£**[redacted] • 275kv £/bay - **£**[redacted] • 400kv £/bay - **£**[redacted] • In-situ bay upgrade - **£**[redacted] UCAs for unit rates are based upon extensive historical analysis of our RIIO-T1 scheme expenditures.
£/MVA element	Proposed RIIO-T2 UCA = **£**[redacted] **/MVA** £/MVA covers costs associated with transformer substation works for Shared Use schemes (including all associated works required within the substation – including switchgear works). UCA derived from linear regression analysis based on substation costs for all RIIO-T1 shared use projects where transformer substation was installed.

Linear assets recovery (same rates apply to both sole and shared use)	£/circuit km UCAs used to recover costs for: OHL new build by applying different unit cost allowances for: • 132kv wood pole at **£[redacted]/circuit km** • 132kv Steel Towers at **£[redacted]/circuit km** • 275/400kv Steel Towers **£[redacted]/circuit km** OHL reconductoring by applying one rate across all voltages at **£[redacted]/circuit km** UGC by applying one rate across all voltages **£[redacted]/circuit km** SS by applying one rate across all voltages **£[redacted]/circuit km** UCAs for unit rates are based upon extensive historical analysis of our RIIO-T1 scheme expenditures.

OHL = overhead line; UGC = underground cable; subsea = subsea cable

2.1.29 Option 3b largely removes the need for separate treatment for atypical projects. However, there may be projects where for several reasons, such as regional/site specific factors or network configuration requirements, are unsuitable to be funded through the volume driver mechanism. These schemes will be put forward for funding via the annual High Value Transmission Project (HVTP) reopener, described in Section 2.3 below.

2.1.30 For schemes to be considered for the HVTP reopener, there would be two trigger criteria. First, the project value must be greater than £25m. Second, the forecast unit costs are at least a third higher than the volume driver UCAs.

d) Justification for the mechanism

2.1.31 As already noted, less than a third of the identified RIIO-T1 schemes that were predicted went ahead. Instead, different schemes proceeded in the period – we therefore require a reactive mechanism that enables us to respond to market requirements. Like in RIIO-T1, we propose an automatic adjustment to our Annual Base Revenue via a volume driver, which is based upon ex ante UCAs. The use of a volume driver alleviates the regulator from the burden of signing off all investment decisions; but still allows visibility and signoff of the parameters set to deliver schemes, allowing TO's to react to customer requirements in a timely manner. Ofgem will also have sight of projects £100m+ via the HVTP mechanism.

2.1.32 RIIO-T2 must ultimately enable us to meet our stakeholder needs. This mechanism is at the heart of this – ensuring we can respond flexibly to the market requirements and to our legal obligations to connect customers, while also ensuring consumers only pay when the need materialises and not before.

2.1.33 It delivers value for money as consumers only pay when the need is certain and not before, and costs are based on efficient historical rates with embedded efficiencies. By retaining the TIM sharing factor (strength of which is to be determined by Ofgem), this will help ensure the incentive remains to find further efficiencies in RIIO-T2 to embed for RIIO-T3.

e) Materiality of the issue

2.1.34 The value will be material. Our best estimate is based on our Likely Outturn Assessment[11], under which we believe the volume driver will support c£407m of investment:

- 928MW of generation requiring c£168m of investment in sole use infrastructure;
- 2380MVA of generation requiring c£211m of investment in shared use infrastructure;
- c£8m of GSP upgrades; and
- c£20m OFTO additional works.

f) Frequency and probability of the issue

2.1.35 The probability of the issue arising during the price control is certain. All our scenarios and our bottom-up analysis suggest that generation connected to our network will be above our Certain View with our Likely Outturn Assessment calculating this to be around 2.5 GW above the Certain View, i.e. the total connected in 2025/26 to be 13.7 GW.

2.1.36 We anticipate the use of the volume driver from year one of RIIO-T2 but the exact frequency is outside our control.

g) Drawbacks of proposed mechanisms and mitigation

2.1.37 The main drawback is that the UCA may not accurately reflect the costs. However, to mitigate this, unlike in RIIO-T1, the UCAs are based on actual historical costs which provides a high degree of certainty over the costs and embeds RIIO-T1 cost efficiencies. This represents value for money. Our preferred disaggregated approach was selected because of its cost reflectivity and its ability to reduce the risk of windfall gains and losses.

2.1.38 Another drawback is that Ofgem will not have sight of the engineering justification for the projects that go ahead under the volume driver mechanism during the RIIO-T2, unlike those in our Certain View. As noted in paragraph 2.1.5, the RIIO-T2 volume driver is intended to cover schemes that will connect from 2023/24 onwards. The reality is that to provide engineering justifications for these now will not in fact provide additional confidence. This is because many of these projects will not go ahead and entirely new ones will emerge. For those that do proceed, many will change in scope. We do not have control over this. Therefore, the engineering justifications provided ahead of submission will in effect be obsolete if and when the projects proceed.

2.1.39 Our approach takes this into account. It is "less automatic" than RIIO-T1 with regards to outlier projects as Ofgem will have the opportunity to review high cost projects. The HVTP mechanism (see Section 2.3)

[11] See SUPPORTING DOCUMENT 3: Planning for Net Zero: Scenarios, Certain View and Likely Outturn, found here: https://www.ssen-transmission.co.uk/riio-t2-plan/planning-for-net-zero-scenarios-certain-view-and-likely-outturn/

will give the regulator full sight of all projects valued £100m+ and those where the costs exceed the UCA by a third or more. These projects can be subject to the provision of an engineering justification pack. We also set out our approach to strategic optioneering (see page 38 of our main Business Plan) and our Strategic Optioneering paper)[12], which all our volume driver projects will be subject to.

2.1.40 All of these guarantee a proportionate approach to intervention, ensuring the regulatory process doesn't act as a barrier to achieving net zero ambitions.

2.1.41 Finally, this proposed approach will impact on the cost to consumers, but it is not possible to accurately set out the impact upfront. In a perfect world, certainty would be available in advance of the RIIO-T2 period in order to profile the cost and impact on consumer bills. The volume driver is in place to mitigate this risk on both the consumer and the network company. It protects the consumer from both over-investment and under delivery by only providing allowances when the need arises. The impact on consumers is justified through clear delivery. Therefore, the volume driver mechanisms are the best alternative to perfect certainty so consumers are no worse off in reality. For the reasons set out above, consumers are better off with the volume driver mechanism than in the absence of one.

*h) V*alue for money and ability to finance

2.1.42 As noted above, we believe this approach offers significantly better value for money for consumers than the RIIO-T1 approach in two key ways:

1. using historical unit cost data rather than forecast data to set the UCAs gives greater confidence on the accuracy and efficiency of the costs (noting the £100m efficiency goal);
2. the UCAs are more reflective of the actual costs incurred.

2.1.43 The above means that consumers can have greater confidence that any outperformance of the UCAs will be as a result of efficiency and not by issues in how the price control was set.

2.1.44 We propose to retain the current RIIO-T1 methodology for recovery of volume driver allowances in RIIO-T2. Our proposal is for recovery of allowances based on an annual lookahead forecast with allowances recovered in equal (25%) portions over a four-year period worked back from the predicted date of connection.

2.1.45 In addition, we propose to apply same crossover mechanism that was included in the RIIO-T1 licence as this provides protection for both consumer and TO and ensures no delay on delivery of schemes.

[12] SUPPORTING DOCUMENT 4. Strategic Optioneering Methodology, found here: https://www.ssen-transmission.co.uk/media/3406/strategic-optioneering-methodology.pdf

2.2 Strategic Wider Works (SWW)

a) Issues and risks the mechanism addresses

2.2.1 The growth of renewable generation in the north of Scotland, coupled to date with the relatively static gross demand, has seen an increase in the magnitude of north to south power transfer. This has driven significant network reinforcements over the past decade. Both the North of Scotland FES and the ESO FES show a continuing need for boundary capacity increases during RIIO-T2 (see pages 31-32 of our Business Plan).

2.2.2 Wider works are defined as "transmission reinforcement works that are designed to reinforce or extend the National Electricity Transmission System which may include works to attain compliance with the terms of the National Electricity System Security and Quality of Supply Standard (or such other standard of planning and operation as the Authority may approve from time to time and with which the licensee may be required to comply in accordance with standard condition D3 (Transmission system security standard and quality of service)."

2.2.3 In general, these works are triggered by a combination of different generation connections. They are required to increase the capacity or extend the network to convey electricity from where new generation is built to where demand is located, as well as the need to comply with network security standards. Wider works outputs are then measured in terms of increases in the electricity transfer capability across system boundaries (or within system boundaries) in accordance with the national security and planning standards for the transmission network.

2.2.4 These projects are driven by the wider system need rather than specific generation projects and are reviewed annually as part of the NOA process. It is expected that such projects will be necessary to accommodate the increased flows of renewable energy across the main transmission boundaries on our network.

b) Ownership of the risks

2.2.5 We only proceed with these projects once a robust needs case has been justified based on the background generation projections and associated project costs. The Strategic Wider Works (SWW) mechanism ensures that investments are only made when they are of benefit to consumers, reducing their risk.

2.2.6 Not progressing these projects or their deferral to the subsequent price control period is likely to result in significant consumer detriment as it may lead to additional balancing costs for the ESO, which are ultimately borne by consumers.

c) The proposed mechanism

2.2.7 We propose a within period determination mechanism to allow funding for these projects when the need arises and can be clearly demonstrated. By waiting until the needs case is made, completed and approved, customers are not asked to pay for these schemes too early. This mechanism should build on the current RIIO-T1 SWW mechanism, which has been a powerful tool in accommodating uncertain and material network investments.

2.2.8 Like the current mechanism, there is no set "window" for submitting a case to Ofgem with these submitted as and when the need arises.

2.2.9 For SHE Transmission, the RIIO-T1 SWW mechanism allows for within period revenue adjustment for projects with a threshold value of £50m that deliver additional transmission capacity at the boundary or sub-boundary of the main integrated transmission system. The revenue adjustment also includes an opex adjustment equal to 1% of the value of the additional wider works output (discussed below).

2.2.10 The existing SWW mechanism should be maintained for wider works projects in RIIO-T2 with a threshold value of £100m, with the volume driver (above) and High Value Transmission Project (HVTP) reopener (below) dealing with projects below the threshold. We believe that the best approach would be to enhance what has already worked well, i.e. reinforcing the positives and considering specific elements that can be improved, such as:

- ensuring the timing and duration of the Initial Needs Case and Final Needs Case are flexible and do not negatively impact/delay the progression of necessary wider works;
- commencing the project assessment, where appropriate, in parallel with the Final Needs Case assessment to ensure timely review of efficiently incurred costs and determination of allowed revenue; and
- broadening the scope of the supporting cost benefit analysis (CBA) to account for wider socio-economic and environmental impacts, particularly in the context of the Scottish and UK Government's carbon reduction targets.

d) Justification for the mechanism

2.2.11 The existing SWW mechanism allows Ofgem to assess the specific costs and risks that each project presents once it is well developed and has greater certainty surrounding the associated costs and benefits. Here Ofgem looks at the full economic impact of the project, including constraint saving costs, across the studied generation scenarios and gains the ability to undertake a more rigorous analysis of solutions being used.

2.2.12 The SWW mechanism for RIIO-T2 should build on the established RIIO-T1 SWW mechanism, making only necessary changes that build on efficiencies and learning.

e) Materiality of the issue

2.2.13 Some Network Output Assessment (NOA) driven projects are certain, well-defined and are set out in our Certain View as Baseline Wider Works (e.g. East Coast Phase 1 and Phase 2) - see pages 42-43 of the Business Plan. Others however are less certain and some currently unknown but could arise during RIIO-T2.

2.2.14 **Eastern HVDC:** The need to reinforce the transmission network in the east and north-east of Scotland has been demonstrated through the NOA process. The latest NOA report (published in January 2019) recommended investment in the east coast network by 2026 in a two-stage approach and in the HVDC link from Peterhead to England with the associated AC onshore works at both ends by 2029. Whilst the case for the SHE Transmission-NGET HVDC link is strong, the project definition and readiness is not sufficiently certain for inclusion in our Certain View in the RIIO-T2 Business Plan. At an estimated cost of £2.2bn, the SWW mechanism remains the appropriate pathway for assessing the need, solution and efficient costs of the proposed reinforcement.

2.2.15 **Scottish Island Links**: It is our expectation that, subject to approvals, there is likely to be significant investment (up to £1.5bn) requirements for our Scottish island schemes spanning both the RIIO-T1 and RIIO-T2 price control periods. We have not presented any of our Scottish island schemes within our Certain View, as the Needs Cases for the Orkney, Western Isles and Shetland links are currently 'in-flight' under the RIIO-T1 SWW mechanism.

f) Frequency and probability of the issue

2.2.16 As outlined above, the probability of the issue arising during the price control is certain due to the already recognised need to reinforce the transmission network in the east and north-east of Scotland.

2.2.17 As the NOA outputs and recommendations are unknown, and as it looks at future possibilities and potential network needs, by definition, these are difficult to forecast at the beginning of the price control.

g) Drawbacks of proposed mechanism and mitigation

2.2.18 The existing SWW mechanism can be time consuming and resource intensive for the TO, Ofgem and the ESO, which could potentially lead to delays in progressing required strategic reinforcements. Such delays could result in significant consumer detriment as it may lead to additional balancing costs to the ESO which are ultimately borne by consumers.

2.2.19 In RIIO-T1, the need for the new strategic reinforcement is supported by CBAs, which assesses the expected increase in generation relative to the existing capacity of the transmission network, as well as forecast costs to consumers if transmission capability is expected to constrain generation. This is compared to the capital costs of the proposed reinforcement and energy transported (measured by avoided constraints). This is increasingly recognised as a very narrow view of the role of energy networks given the wider socio-economic and environmental impacts of energy.

2.2.20 The drawbacks of the mechanism can be reduced by applying a series of practical process changes to the existing mechanism, as outlined in paragraph 2.2.10 above.

2.2.21 All uncertain costs have an impact on consumers' bills as they lead to changes to network companies allowed revenue. Given the significant costs associated with these strategic reinforcements it is important that an extensive review is undertaken to ensure that investments are only made when it has been clearly demonstrated that these are needed and will deliver benefits to the consumer.

h) Value for money and ability to finance

2.2.22 The mechanism allows Ofgem to undertake a detailed assessment of the need for the reinforcement, the solutions that have been considered, and whether the costs of the proposed solution are outweighed by the potential benefits to consumers.

2.2.23 Works will only commence once costs have been assessed and deemed efficient, and the subsequent TO revenues have been approved. This provides certainty to the TO that its costs and the associated revenues will be recoverable. It also ensures that consumers are only paying for efficiently incurred costs.

2.3 High Value Transmission Projects (HVTP)

a) Issues and risks the mechanism addresses

2.3.1 Ofgem has recently proposed replacing the SWW mechanism with the LOTI (Large Onshore Transmission Investment) mechanism, widening its scope to cover not just wider works reinforcements, but all onshore transmission projects valued at £100m or above, including sole and shared used connection driven projects.

2.3.2 We propose that the existing SWW mechanism remains for wider works reinforcements (as currently defined but with a £100m threshold for RIIO-T2), and a new, separate, 'High Value Transmission Project' (HVTP) mechanism, similar to the High Value Project reopener available to DNOs under RIIO-ED1 (Special Condition CRC 3F1), is introduced for transmission projects valued above £25m.

2.3.3 This will be for projects which:

- are not eligible as SWW;
- volume driven projects (generation connections, GSP upgrades, OFTO driven works) above £100m; and
- volume driven projects where the forecast unit costs are at least a third higher than the volume driver unit cost allowances.

2.3.4 This includes, but is not limited to:

- regional investments to connect new renewable generation and accommodate changes in the use of energy due to electrification (sole-use and shared-use infrastructure);
- system driven investment to ensure the operability of the network with a more flexible generation and demand mix (system infrastructure); and
- atypical projects, such as those that do not neatly fit into growth driven (load) or asset driven investments, such as our Skye project, described below.

2.3.5 The HVTP mechanism would cover schemes that were not included in our Certain View baselines due to uncertainties prevailing at the time of setting the price control allowances.

b) Ownership of the risks

2.3.6 Not progressing these projects or their deferral to the subsequent price review is likely to result in detriment to both our customers (e.g. developers) who are looking to connect to our network, and the end consumer who want to know they are benefitting from network reinforcements at the time when they are most needed.

2.3.7 We only progress with these projects once the need and efficient costs of the project have been clearly demonstrated. This ensures that consumers are only picking up efficiently incurred costs, and only when they know they are needed.

c) The proposed mechanism

2.3.8 The HVTP mechanism allows for within period revenue adjustment for projects with a threshold value of >£25m, which meet the criteria outlined in paragraph 2.3.3 above and in respect of which there is no other mechanism for the adjustment of allowed expenditure levels during the price control period.

2.3.9 We propose a within period determination mechanism to allow funding for projects when a needs case with clear outputs, and a statement of costs, supported by an appropriate CBA have been provided to Ofgem.

2.3.10 For projects between £25m and less than £100m we propose an annual reopener window (e.g. September of each year) and for projects greater than £100m we propose, similar to SWW, that we make the case when the need arises.

d) Justification for the mechanism

2.3.11 As outlined above, the existing SWW mechanism was designed and introduced to serve the specific purpose of assessing the need for large strategic transmission reinforcements which strengthen or extend the transmission network ('wider works'). Whilst this mechanism is considered appropriate for wider works, the process is not suitable for all large transmission projects.

2.3.12 Timing is often critical to these projects, therefore the various stages of assessment under the existing SWW mechanism or Ofgem's proposed LOTI mechanism, which can take a number of years, could lead to unnecessary delays. In addition, the CBA undertaken for a SWW is specifically designed to assess whether the proposed reinforcement and associated increase in transmission capability is economic for consumers, when compared with the option for the ESO to manage bottlenecks on the transmission network through constraint payments. This assessment is not suitable for transmission reinforcements which have been demonstrated as needed for the purposes of, for example, connecting new generation and demand, or replacing existing parts of the transmission system which are degrading and are required for security of supply.

2.3.13 The HVTP mechanism would allow for a bespoke/tailored assessment of project need and costs, whilst still managing project delivery in a timely manner to avoid unnecessary delays to required network investments. The mechanism would allow TOs to propose within period adjustments to baseline expenditure allowances for these costs when there is more certainty on the need and proposed solution.

e) Materiality of the issue

2.3.14 **Skye:** In our July and October draft Business Plans we noted that generation connection requests in the Skye region had led to a review of our network development plans for the Fort Augustus to Skye overhead line. The efficient development of this part of the transmission system is complex to assess as it must take into account: maintaining security of supply for local communities, the existing asset, future system need (both demand and generation) and other network developments (including the Western Isles). There is an evidence-based need to invest in this part of the system during the RIIO-T2 period, however the detail of the investment remains subject to stakeholder consultation and the granting of planning consents. This is a clear example of where we want to ensure we have certainty that we are doing the right thing, taking a holistic approach to our investment decisions. With the potential requirement to invest an estimated £250-300m to upgrade and replace the existing infrastructure in Skye, the HVTP mechanism would allow for a detailed within period assessment of the reinforcement and the expected costs once a fully considered proposal has been developed. We want to minimise risk to consumers of over or underfunding important RIIO-T2 network investment opportunities. Further details on the Skye project can be found in page 60 of our main Business Plan.

2.3.15 **Volume driven projects:** Whilst the majority of volume driven projects should be covered by our volume driver, we recognise that for high value volume driven reinforcements which are estimated to cost £100m or more, giving Ofgem early sight of these reinforcements and the opportunity to assess project costs is important to ensure only efficiently incurred costs are incurred by the consumer. Given the success of offshore wind developers in the 2019 CfD auction along with the ongoing increase in renewable development onshore, these incidents could potentially become more frequent throughout RIIO-T2. The HVTP mechanism would allow for a within period assessment of these volume driven projects within the required timescales to meet the need driving the reinforcements whilst minimising the risk to consumers of funding inefficient costs. Our likely outturn view[13] currently has one potential project that exceeds £100m and would be subject to the HVTP mechanism rather than the volume driver. It is currently costed at c£118m but this is an immature estimate and it is not possible to accurately predict which projects will come forward during the period.

f) Frequency and probability of the issue

2.3.16 As outlined above, the probability of the issue arising during the price control is certain (due to Skye), and the materiality is high.

g) Drawbacks of the proposed mechanism and mitigation

2.3.17 For volume driven projects (especially generation connections) timing can be critical and any unnecessary delay for a reopener may compromise the success of a project. A volume driver would provide better flexibility ensuring allowance is available. However, it is recognised that the volume driver may not be suitable for assessing the costs of atypical projects, and does not give Ofgem early sight of high value projects above £100m.

2.3.18 The HVTP mechanism can be designed to allow the scope and duration of the needs case and cost assessment to vary depending on the terms of the project. For example, for time-constrained generation connection driven projects, an expedited needs case assessment may be required, with the opportunity for Ofgem to still undertake a detailed assessment of the cost efficiency of the project. Also, as noted above, the SWW mechanism and CBA approach may not suitable for all projects, as we are recognising on our Island projects.

2.3.19 Uncertain costs have implications for consumers' bills as they lead to changes to a network company's allowed revenue. However, by waiting until the need is certain and the costs are assessed, this impact on bills will be reflective of the work required.

h) Value for money and ability to finance

2.3.20 The mechanism allows Ofgem to undertake a detailed assessment of the works, and whether the costs of the proposed solution have been efficiently incurred.

[13] In deriving the likely outturn view, we considered: the status of known generation developments, contracted and in scoping, and the potential timeline for connection; the potential for continued growth of distributed generation; and the availability of transmission capacity for new generation connections and growth that could be delivered and utilised within the RIIO-T2 period. This allows us to reach the view that generation connected will exceed the Certain View by around 2.5 GW.

2.4 Pre-construction

Introduction

2.4.1 Our Certain View approach is based on the fundamental principle that funding for infrastructure investments should not be released until the need has been demonstrated. This protects consumers from uncertain costs and avoids the complicated clawback of funding that has not been used. However, the risk associated with this approach is that funding is not released on time and potentially infrastructure investment is delayed, thus hindering net zero ambitions. To mitigate this risk, there are two key elements in our Business Plan:

1. A suite of flexible regulatory mechanisms that release funding for investment when it is required, as set out in this paper - volume driver, SWW, HVTP (all described above) and reopeners (described below).
2. A clear commitment to undertake **pre-construction** works to ensure that these investments are ready for construction when the need is certain. This includes the design and consent of connections for new generation developments.

2.4.2 Our proposal for pre-construction for uncertain projects in RIIO-T2 is split into three areas as follows:

1. **Volume driver schemes:** for new connection schemes funded under the volume driver, we propose to include the pre-construction costs as part of the overall volume driver UCAs.
2. **Strategic schemes:** for the development of large strategic schemes, we propose a **use it or lose it pot.** Unused funding will be handed back at the end of the RIIO-T2 period.
3. **T3 schemes:** we anticipate there will be a requirement for us to incur pre-construction expenditure on projects that will be constructed after 31 March 2026 RIIO-T3. We propose a pot which will be subject to a **symmetric 'true up'** at the end of the RIIO-T2 period.

2.4.3 It is important that the pre-construction pots have flexibility for substitution. While we may be able to identify works across transmission boundaries and possible RIIO-T3 schemes, our experience in RIIO-T1 has clearly shown that, beyond our control, things change. We must be able to adapt to these changes and substitute schemes in and out of these pots.

a) Issues and risks the mechanism addresses

2.4.4 The pre-construction mechanisms will ensure we have the investment to give the required focus in the project development phase to not only avoid delay and meet net zero ambitions, but to deliver early value.

2.4.5 The risk associated with our Certain View approach is that funding is not released on time and potentially infrastructure investment is delayed, thus hindering net zero ambitions. Appropriate mechanisms to provide efficient levels of pre-construction expenditure is vital to mitigate this risk.

2.4.6 The pre-construction phase will also ensure we develop the most efficient solutions and carry out preliminary design activities to minimise unnecessary cost exposure during the delivery phase. It is this phase that unlocks the potential for efficiency savings, driving considerable consumer benefit.

b) Ownership of the risks

2.4.7 The uncertainty is centred around need and costs.

2.4.8 Regarding need:

- For new connection schemes funded under the volume driver, we will only undertake pre-construction when it is necessary to meet our contracted position.
- For strategic schemes, we will only undertake pre-construction for schemes that have a NOA proceed signal, we have strong evidence that they will likely end up in NOA or there are wider generation drivers for large shared use infrastructure schemes. We have included large shared use infrastructure schemes within our strategic category to reflect our experience from the RIIO-T1 period where we've incurred significant preconstruction expenditure in the development of large schemes (e.g. Scottish islands) which are driven by complex background generation drivers.
- For load-driven RIIO-T3 schemes, the same principle regarding the volume driver above applies and for non-load, we will have gained confidence on the need through our condition-based risk management.

2.4.9 Of course, things change and although we mitigate this using evidence on which to base our decisions, we may incur some pre-construction costs for projects that do not proceed.

2.4.10 The main risks that remains, as with other areas, is with respect to the costs and the key questions are if costs are efficient and if the costs are sufficient.

2.4.11 For the volume driver, the pre-construction costs are embedded therefore, what is set out in paragraphs 2.1.12 to 2.1.16 applies here. Ultimately, any over or underspend will be subject to the TIM sharing factor in balancing risk.

2.4.12 For both large strategic schemes and the RIIO-T3 schemes, the pots are not subject to the TIM sharing factor but will be subject to an end of period efficiency assessment. This assessment will ensure that we continue to make efficient decisions when investing in pre-construction.

2.4.13 To help ensure we have sufficient costs – i.e. there will be enough in our allowances to undertake the necessary pre-construction works – substitution within and across pots is very important as noted in paragraph 2.43.

c) The proposed mechanism

2.4.14 For the **volume driver** new connection schemes, the pre-construction costs as part of the overall volume driver UCAs. Section 2.1 describes this mechanism.

2.4.15 For the development of **large strategic schemes and other large schemes** (e.g. such as Skye), our proposal is to set out a baseline allowance based on an estimate of required pre-construction funding for such schemes during the RIIO-T2 period. Our experience from RIIO-T1 highlighted the difficulty in assigning defined pre-construction expenditure on an individual scheme basis since it's impossible to predict which schemes will progress. For NOA driven schemes, we propose setting the allowances based on pre-construction works across each of the transmission boundaries along with general pots covering the ongoing NOA interface with the ESO, and regional development plans. This approach is consistent with the NOA approach to optioneering. For HVTP type projects, we propose setting allowances based on a list of schemes that we have current strong evidence will proceed with a mechanism in place to substitute schemes based on potential changes in generation drivers. This baseline allowance will form a **use it or lose it pot** which will be reconciled at the end of the price control for efficiently incurred costs. This pot is asymmetrical whereby we return unspent allowances but do not request more.

2.4.16 For the development of **RIIO-T3 schemes,** both growth-driven (load) and asset-driven (non-load), we will take a similar approach. From data we have from RIIO-T1, we estimate that pre-construction expenditure accounts for 7.5% and 6.5% of total expenditure for similar historical load and non-load schemes, respectively. We apply those percentages to our cost estimates[14] of schemes we think will require development during RIIO-T2. These will be subject to a **symmetric 'true up' mechanism** to adjust allowances at the end of the price control period for efficiently incurred costs. This is symmetric as there is greater uncertainty with regards to the growth driven projects that will come forward for construction in RIIO-T3. The level of connections coming forward is increasing significantly and we may be required to increase the pre-construction expenditure above historical levels.

2.4.17 Finally, we propose substitution across and within pots (within pots for the RIIO-T3 schemes). Some schemes that were identified as RIIO-T3 may accelerate and move into RIIO-T2 and vice versa.

2.4.18 If Ofgem adopt a different mechanism for large projects to our proposed SWW and HVTP, we seek to recover appropriate pre-construction through alternative arrangements.

d) Justification for the mechanism

2.4.19 As set out above, pre-construction funding is required to provide a clear commitment to undertake pre-construction works to ensure that investments are ready for construction when the need is certain. This will reduce the risk associated with our Certain View approach that funding is not released on time and

[14] These are immature at this stage and can range from -50% to 100% by the time the project is commissioned.

potentially infrastructure investment is delayed, thus not realising the suite of potential benefits to stakeholders and the GB consumer.

e) Materiality of the issue

2.4.20 This is a material issue. We estimate pre-construction costs, excluding the costs embedded in the volume driver, to be £142m comprising:

- £118m for the SWW projects; and
- £24m for the RIIO-T3 projects.

f) Frequency and probability of the issue

2.4.21 The probability of the issue arising during the price control is certain. All our scenarios and our bottom-up analysis suggest that greater investment in our network will be required beyond our Certain View. Therefore, we will need to undertake pre-construction for projects that will commence in RIIO-T2 and in RIIO-T3 that are outside our Certain View.

g) Drawbacks of proposed mechanism and mitigation

2.4.22 For the volume driver ex ante UCAs the main drawback would be that the UCAs are set incorrectly. But by using historical cost and testing for price reflectivity, we believe the UCAs are based on solid evidence.

2.4.23 The main drawbacks of the use it or lose it mechanism is getting the size of the pot right so that a) it is large enough to ensure the issue that it is trying to address is met (net zero and sufficient investment to realise overall project efficiencies) and b) it still drives efficient behaviour which pass-through type mechanisms may not. The drawbacks are reduced by setting the pot based on historical data and applying it to schemes that we can justifiably see as possibly going ahead in RIIO-T2.

2.4.24 Another drawback of both the use it or lose it pot and the symmetric true up mechanism is ensuring efficiency during the period as the TIM sharing factor doesn't apply. This is mitigated by having annual and end of period efficiency assessments, with the annual assessments part of the Regulatory Reporting Pack (RRP) process. The use it or lose it pot also sets a maximum expenditure which drives efficiency; we can't spend more than the pot. While the symmetric mechanism doesn't have a maximum limit, this is justifiable due to greater uncertainty around the pre-construction requirements for RIIO-T3 projects.

2.4.25 Given that it is difficult to predict with certainty at this stage which schemes will need to be developed further, it is vitally important that both pots (use it or lose it and symmetric true up) allows for substitution of schemes.

h) Value for money and ability to finance

2.4.26 As noted above, pre-construction funding in and of itself delivers value for money. Insufficient investment in pre-construction can result in incomplete or flawed scoping, or failure to identify and mitigate execution risk (such as ground conditions). This increased project risk can have a negative consequential impact on the efficiency of procurement and increases the likelihood of failed execution.

2.4.27 In terms of our approach to setting the pre-construction mechanisms, we based our forecast expenditure on historical schemes of a similar nature which should give confidence as to the costs. By setting a limit of the use it or lose pot, this will act as an incentive to keep the costs down, as will the end of period reviews of efficiently incurred costs. The TIM sharing factor will play its role in ensuring efficient delivery for the volume driver schemes.

2.5 Operating cost escalator

a) Issues and risks the mechanism addresses

2.5.1 The mechanisms identified above address how the necessary capital allowances are identified and adjusted during the price control. For the same reasons that investment requirements are uncertain, it is also difficult to accurately assess our future operating costs associated with these new assets.

2.5.2 We have made a distinction between our business as usual operating costs and the additional operating costs that are incurred following the completion of uncertain projects. We propose that an operating cost escalator is automatically built into our uncertainty mechanisms to address these additional operational costs.

2.5.3 For large projects (volume driver, SWW, HVTPs) we propose to include an automatic cost escalator of 1% of the capital expenditure incurred, which would be triggered in the year following completion. We believe that because this mechanism applies automatically and will therefore reflect the actual outturn, it will cover for the uncertainty of timing and future level of operating costs associated with new large value assets. This design of the cost escalator is currently used in the volume drivers and strategic projects in RIIO-T1 and effectively and efficiently accommodates the uncertainty.

b) Ownership of the risks

2.5.4 The uncertainty stems from the need for the capital investment and the management of that risk is as per above from the volume driver, SWW and HVTPs. We can also manage the operational cost risk by ensuring that the allowances are only permitted when the capital costs are incurred and not before.

c) The proposed mechanism

2.5.5 It is an annual automatic cost escalator of 1% of the capital expenditure incurred, which would be triggered in the year following completion.

d) Justification for the mechanism

2.5.6 Additional capital costs will be incurred during RIIO-T2 to that set out in our Certain View and these will always have an operating cost associated with them.

e) Materiality of the issue

2.5.7 Materiality is linked to the value of the above mechanisms which we have in the region of £4.4bn. 1% of this is £44m.[15]

f) Frequency and probability of the issue

2.5.8 This is linked to the above mechanisms and we are certain it will be used. We know that the volume driver will be used, as will the SWW mechanism and the HVTP is also very likely too.

g) Drawbacks of proposed mechanism and mitigation

2.5.9 The main drawback concerns whether the escalator is set correctly, resulting in consumers paying more than the costs incurred.

2.5.10 This drawback is reduced by basing the escalator on a low end of acceptable operating costs escalators – at 1%. The alternative would be pass-through but as these costs are within our control, it is in the consumers' interests that we have a target to outperform through making efficiency savings in RIIO-T2.

h) Value for money and ability to finance

2.5.11 The Transmission Connections and Use of System Code (CUSC) allows 2% for operating costs while the Distribution Connection Charging Methodology Statement (CCMS) allows between 1% and 2.5%. By selecting 1%, this is the low end and consistent with precedent.

2.6 Sustainability cost escalator

a) Issues and risks the mechanism addresses

2.6.1 We have a clear goal of a one third reduction in our greenhouse gas emissions by 2026 compared to 2018/19 levels. This will largely be achieved through three key interventions:

- substation electricity use: implementing energy efficiency and installing renewable microgeneration (e.g. PV);
- installing alternatives to SF6 on our network; and

[15] Volume Driver = £407m, SWW = £2.2bn + £1.5bn islands (excluding the £118m as can fall here of the volume driver), HVTP = £300m Skye.

- 50% of our operational transport fleet becoming electric vehicles by the end of RIIO-T2.

2.6.2 We also have a commitment to wider sustainability goals including biodiversity net gain, no net loss for woodland, embedding landscape and visual improvements into all projects, as set out in our Sustainability Action Plan[16].

2.6.3 The incremental costs of such interventions are clearly set out in our Certain View of investments. To meet our goal, the same interventions must apply to additional investment we make over and above the Certain View.

2.6.4 Therefore, like the operating costs, we have made a distinction between our business as usual sustainability costs and the additional sustainability costs that are incurred following the completion of uncertain projects. We propose that a **sustainability cost escalator** is automatically adjusted for **volume driver projects** to address these important additional costs.

2.6.5 For volume driver projects, we propose to include an automatic cost escalator of 0.5% of the capital expenditure incurred, which would be triggered in the year following completion. We believe that because this mechanism applies automatically and will therefore reflect the actual outturn, it will cover for the uncertainty of timing and future level of operating costs associated with new large value assets.

b) Ownership of the risks

2.6.6 The uncertainty stems from the need for the capital investment and the management of that risk is as per above from the volume driver. We can also manage the additional sustainability cost risk by ensuring that the allowances are only permitted when the capital costs are incurred and not before.

c) The proposed mechanism

2.6.7 It is an annual automatic cost escalator of 0.5% of the capital costs, which would be triggered in the year following completion. Our total load related capital costs under our Certain View are £891m and the costs for our sustainability actions for the 26 load projects are £4.2m, 0.5% of total load capital costs. This is applied automatically when allowances are incurred via the volume driver mechanism.

d) Justification for the mechanism

2.6.8 Additional capital costs will be incurred during RIIO-T2 to that which are set out in our Certain View and these will always have sustainability costs associated with them if we are to meet our stakeholder-led goal of a one-third reduction in greenhouse gas emissions.

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[16] SUPPORTING DOCUMENT 16A: Sustainability Action Plan, found here: https://www.ssen-transmission.co.uk/riio-t2-plan/sustainability-action-plan/

e) Materiality of the issue

2.6.9 Linked to the value of the materiality of volume driver above which we have in the region of £407m, 0.5% of this is £2m. However, this is only for those schemes in our likely outturn view. The volume connected may be greater than this.

f) Frequency and probability of the issue

2.6.10 This is linked to the above mechanisms and we are certain it will be used. We know that the volume driver will be used.

g) Drawbacks of proposed mechanism and mitigation

2.6.11 The main drawback concerns whether the escalator was set correctly, which could result in consumers paying more than the costs incurred or us under-recovering costs.

2.6.12 This drawback is reduced by basing the escalator on the costs forecast in our Certain View, which will be subject to significant scrutiny from Ofgem. The alternative would be pass-through but as these costs are within our control, it is in consumers' interests that we have a target to outperform through making efficiency savings in RIIO-T2.

h) Value for money and ability to finance

2.6.13 As above, the mechanism will only apply when costs are incurred. Both our total load capital costs and sustainability costs will be subject to a full cost assessment from Ofgem. If deemed cost efficient, this will set a limit for the escalator (currently estimated at 0.5%).

3 Unknown External Costs

Introduction

3.1 The drivers of uncertain external costs are decisions by or actions of third parties, hence, not in our direct control. For example, a decision by the UK Government to require networks to comply with enhanced cyber security standards. There is a clear need for mechanisms that can effectively respond to material changes in certain cost drivers and which the regulator, stakeholders and/or network company could not know in advance. These comprise:

- **reopeners**: re-setting allowances during a price control when the driver of costs become more certain; and
- **pass-through costs**: costs which can vary annual revenue in line with the actual cost, either because they are outside our control or because they have been subject to separate price control measures.

3.2 We believe there is a case in RIIO-T2 to include reopeners for efficiently incurred costs in a limited number of areas where the costs and level of activity are outside our control and sufficiently uncertain.

3.3 It is better to determine cost allowances when the need and associated cost is more certain. To do so prematurely during the price control review can introduce a risk premium as the continued uncertainty may result in consumers paying more than is necessary to efficiently deliver the required output in each of these areas.

3.4 We believe the case for reopeners is justified; the RIIO-T2 control has no mid-period review, unlike RIIO-T1, and the pace of change and level of uncertainty is higher than ever.

3.5 We are proposing eight reopeners, which include those Ofgem has proposed (Cyber Resilience and Physical Site Security within the Third Party Driven Need reopener, the Whole System Coordinated Adjustment mechanism and VISTA):

1. Operability and system management (including Black Start);
2. Third Party Driven Need;
3. Landowner Compensation;
4. Subsea Cable (interference, damage and faults);
5. HVDC Centre;
6. Brexit Import Charges;
7. VISTA (as per Ofgem's proposal); and
8. Whole System Coordinated Adjustment (as per Ofgem's proposal).

3.6 Two reopener windows are proposed - one at approximately the mid-point (Summer/Autumn 2023 following the submission of the second Regulatory Reporting Packs in July 2023) and at the end of the price control - for the first five reopeners listed. An annual window is proposed for Brexit as part of the annual RRP submission and for Ofgem's Whole System CAM. For VISTA this will be as/when the need arises.

3.7 It is necessary to establish a materiality threshold for each of the first six listed individual reopener mechanisms to control the number and frequency of changes to allowances. We suggest 1% of Annual Base Revenue in line with that applied in RIIO-T1. VISTA is subject to its own rules. The 8th listed – Ofgem's Whole System CAM – requires a materiality triggers when the overall value of the project exceeds £20m.

3.8 We also believe the costs of all six should be logged-up and if the costs of all our reopeners reach a threshold of 3% of Base Revenue then the incurred costs should be subject to an efficiency review at the end of the price control period. Where costs are deemed to have been efficiently incurred, a one-off Regulatory Asset Value (RAV)/cash adjustment should be made at the end of the price control and should also reflect the costs of financing this expenditure during the period. This should not limit the option to apply for a reopener and to recover these costs within the period where the 1% individual materiality threshold has been exceeded.

3.9 The proposed windows, materiality and noted issues across these eight reopeners is shown below.

Figure 3.1 Reopener proposals

<table>
<tr><th>Reopener</th><th>Issues</th><th>Windows</th><th>Materiality</th></tr>
<tr><td>1. Operability and system management, including blackstart</td><td>Includes a UCA volume driver for known costs but unknown volumes</td><td rowspan="5">Mid point (Summer/Autumn 2023)
End of price control (July 2026 RRP)</td><td rowspan="6">Individual: 1% annual base revenue
Collective: 3% annual base revenue (net of any adjustments made)</td></tr>
<tr><td>2. Third Party Driven Need</td><td>Includes use of early 2021 Cyber reopener</td></tr>
<tr><td>3. Landowner compensation</td><td></td></tr>
<tr><td>4. Subsea cable faults</td><td></td></tr>
<tr><td>5. HVDC Centre</td><td></td></tr>
<tr><td>6. Brexit Import</td><td></td><td>Annual</td></tr>
<tr><td>7. VISTA</td><td></td><td>When need arises</td><td>No materiality applies</td></tr>
<tr><td>8. Whole System CAM</td><td></td><td>Annual</td><td>£20m</td></tr>
</table>

3.10 As noted in Chapter 1, Ofgem requires that for each uncertainty mechanism we provide detail against nine headings. For three of these - justification for the mechanism; drawbacks of proposed mechanism; and mitigation; and value for money and ability to finance – we note there are pertinent points that apply to all reopeners and are not specific to the subject matter of the reopener. To avoid repetition, we note these generic points here and only additional subject matter specific points in each individual section, where appropriate.

Justification for the mechanism

3.11 Reopener mechanisms allow changes to a company's allowed revenues to be determined considering what happens during the price control period. They help to ensure that consumers only pay for the outputs that are delivered.

3.12 Reopeners also allow us to deal with changes within the price control which could not be assumed or forecasted at the outset and are outside our control. These changes could lead to considerable investment and a reopener can adjust allowed revenue to cover these costs.

3.13 It is better to determine cost allowances when the need and associated cost is more certain. To do so prematurely during the price control review can introduce a risk premium as the continued uncertainty may result in consumers paying more than is necessary to efficiently delivery the required output in each of these areas.

Drawbacks of proposed mechanism and mitigation

3.14 The main drawback is the additional process required for network companies to make a reopener submission, for Ofgem to assess the submission and then to make the revenue adjustments, but this is mitigated by a materiality threshold.

3.15 The alternatives to reopener mechanisms would be either greater compensation for the company to manage the additional risk (e.g. larger cost of equity) or the provision of ex ante allowances. The former would then require a mechanism for unspent allowances to be returned (a strong possibility), thus not removing the drawback of additional process noted above as a drawback. The latter would need to be significant to compensate for some of the material risk (e.g. Black Start alone could result in additional investment of £200m).

3.16 Another alternative uncertainty mechanism to a reopener could be pass through but when the need becomes certain the costs are within our control to manage efficiently. As such, it is better that they are subject to the TIM sharing factor whereby we will be incentivised to find cost efficiencies.

3.17 Finally, as noted previously the drawbacks of any uncertainty mechanisms is that the additional costs will have an impact on consumers' bills as they lead to changes to network companies allowed revenue and it is also not possible to accurately set out the impact on bills upfront. However, if we had perfect certainty that's when allowances would be profiled. Therefore, the reopener mechanisms, like all uncertainty mechanisms, are not wildly different to perfect knowledge, as decisions and funding will be informed and evidence based, so consumers are no worse off in reality.

Value for money and ability to finance

3.18 On balance, adjusting the Totex allowances when the need becomes certain but ensuring the costs are subject to an efficiency assessment and to the ongoing efficiency incentive (TIM sharing factor), provides the optimal solution for both the company and for consumers. It balances the risk, with the process, to keep costs down by releasing funding only when the need is more certain.

3.1 Operability and system management (including Black Start)

a) Issues and risk mechanism addresses

3.1.1 Through the Planning Request mechanism under System Operator - Transmission Owner Code Procedures (STCP), the ESO can directly ask us, as the TO, to undertake work for which no ex ante allowances have been set relating to system operability. Given the changing and evolving nature of the network giving rise to new system requirements and the widening scope of the ESO to look at wider system issues and solutions, we believe such requests are likely to continue, if not increase.

3.1.2 We do not have certainty of what the projects will involve but it is important that we are able to respond, and efficient cost allowances are provided, to requests from the ESO or other unforeseen operability issues that emerge to protect consumers and wider stakeholders from a non-compliant network.

3.1.3 Within the ESO's ambition to promote competition in the provision of solutions to system needs, where appropriate, we will be responding to the ESO's open call for solutions (as in the current ESO pathfinder initiatives). Should any of our solutions be accepted as the most economic solutions, we need to ensure that funding is released to allow us to progress in a timely fashion. While these ESO initiatives are intended as an investigation into the possible extension to the NOA process, we feel that the arrangements for funding projects recommended by the NOA may not adequately cover these cases, especially where the projects do not meet the SWW criteria.

b) Ownership of the risks

3.1.4 Where the costs and level of activity are outside our control it is better to determine cost allowances when the need and associated cost is more certain. Inability to mitigate the system issues outlined above risks non-compliance with licence obligations.

c) The proposed mechanism

3.1.5 The operability uncertainty mechanism comprises to parts:

A. A volume driver for areas where we have data to set a unit cost allowance (UCA) to deliver the solution; and

B. A mid and end of period reopener, with a materiality of 1% of annual base revenue, for those areas where there is also uncertainty on the costs.

Part A: Volume Driver and UCAs

3.1.6 We propose a volume driver with agreed UCAs for two areas. Shunt reactor compensation schemes which will cover all static shunt reactive compensation schemes i.e. shunt reactors and mechanically switched capacitor with damping network (MSCDN) shunt capacitors. We also propose a volume driver mechanism for ESO requested inter-trip schemes.

3.1.7 **Shunt reactors:** As the transmission network continues to move through a period of unprecedented change, the operability challenges on the network increase. One of these issues is the difficulty in controlling transmission voltages under a low loaded network. The factors that contribute to this are the closure or limited operation of traditional synchronous generation, an increase in renewable generation and increased embedded generation, leading to reduced transmission load at the time of minimum demand. In RIIO-T1 we installed 300MVAr of reactive compensation through shunt reactors to help alleviate this issue.

3.1.8 If the challenges of controlling voltage issues on the network continue, with the sustained growth in renewable generation in the north of Scotland, further work will be required to install shunt reactors onto the network. We propose that these projects would be funded through a volume driver mechanism that would be based on a £/MVAr unit cost (in the range of £[redacted] /MVAr). This mechanism would allow expenditure to be recovered if and when shunt reactors are required. The UCA has been calculated using historical costs for installing similar projects through RIIO-T1.

3.1.9 **Inter-trips:** The ESO requires inter-trip solutions to prevent circuit overloading where generation may be reduced or disconnected following a system fault event. We are unable to predict if and when the ESO will require this solution and what generators will be able to offer this service to the ESO. We have delivered one ESO driven inter-trip request in RIIO-T1 and had a number of queries and requests for inter-trips in the RIIO-T1 period from the ESO. We believe this will continue and may increase in the RIIO-T2 period. We are proposing a volume driver to deliver ESO driven strategic inter-trips as there is uncertainty around when schemes will be required. This volume driver would be used for inter-trips that are on a localised and interconnected network.

3.1.10 Given that there may be the two options when installing an inter-trip; extending an existing inter-trip scheme to a new generator and a installing a new inter-trip scheme, we propose two UCAs based on historical data:

- £[redacted] per new inter-trip scheme; and £[redacted] for each additional connection point above two; and
- £[redacted] to extend an existing inter-trip scheme.

3.1.11 The volume driver approach will allow allowances to be flexed if/when required and allow the work as requested by the ESO to be carried out by us.

Part B: Reopener

3.1.12 As noted above there are other, potentially significant, operability issues that may emerge during RIIO-T2, but we have neither certainty on need nor on costs. The most notable concerns are System Harmonics Filters, complex inter-trip and Active Network Management (ANM) schemes, and Black Start.

3.1.13 **System Harmonics:** Harmonic resonance can cause the amplification of background harmonics of the network to levels that breach the G4/5 planning levels and results in potential non-compliance. This is an issue which is increased by the likelihood of wind generation, and potentially combined effects of generators, and DSOs. Issues are technically challenging, and more likely on our transmission network than other areas of GB.

3.1.14 Harmonics can be mitigated with the installation of harmonic filters onto the network. Given that we have not delivered harmonic filter projects in the RIIO-T1 period, and do not have harmonic filter projects in our Certain View, it is not possible for us to confidently set a UCA for delivering this solution. Therefore, we propose the use of a reopener.

3.1.15 **Active Network Management solutions:** This is for more complicated ANM schemes that are part of an interconnected system, where the ANM scheme includes constraint point(s) and controlled point(s) on the Main Interconnected Transmission System (MITS). These are generally widespread and may not be static depending on generation and demand dispatch pattern and network configuration. ANM schemes instruct energy generators, via automated controls, to limit their power output thus avoiding too much energy being put onto the network that could otherwise cause outages and system faults. Calculations of the allowed amount of power that can be put onto the network are derived from real-time network measurements. These schemes are not standard and cannot be delivered using a volume driver unit cost allowance given the potential third party costs and operation and maintenance. Therefore, we are proposing ANM schemes would be subject to the wider operability reopener.

3.1.16 **Black Start**: Scotland is a single Black Start contracting zone and currently the ESO has Black Start contracts generators in Scotland and through the use of hydro stations and generation are able to provide skeleton restoration. However, if the operational status of large thermal generating stations changes, the ESO will have to adopt an alternative Black Start strategy. This may result in us having to carry out significant works to ensure the ESO is able to implement the strategy. We continue to engage with the ESO, Government and other TO's on the issue of Black Start.

3.1.17 Given the uncertainty around the future Black Start strategy it is not possible for us to predict the solutions and works that would be required to deliver the new strategy. We propose the use of a reopener at the midpoint and close out to allow for allowances to adjust for the required works to be carried out for Black Start or any other significant operability issues that emerge that a) are driven by a third party (e.g. the ESO), or b) could not be reasonably foreseen as we submit the business plan in December 2019.

d) Justification for the mechanism

3.1.18 We can't control and foresee the operability issues but know that these are becoming increasingly likely.

3.1.19 Both the volume driver and the reopener will allow changes to be made to our allowed revenues depending on what happens during the price control period and helps to ensure that consumers only pay for the outputs that are delivered.

e) Materiality of the issue

3.1.20 Given both the uncertainty surrounding the number of potential requests from ESO and the uncertainty of operational status of large thermal generating stations regarding Black Start, it is difficult to fully quantify the materiality on expenditure in this area. However, what we do know is that in RIIO-T1 for shunt reactors alone we spent c£9m. It is also possible that Black Start costs alone could reach £200m.

f) Frequency and probability of the issue

3.1.21 The frequency and probability of ESO requests are also difficult to determine. Ideally, the ESO would be able to estimate the frequency and probability of this issue during RIIO-T2.

3.1.22 However, given the number of requests received through the RIIO-T1 period and the potential for accelerated decarbonisation through RIIO-T2, these ESO requests for Black Start, reactive power and inter-trip solutions are likely to increase.

3.1.23 With the GB energy industry decarbonising, large power stations have been closing and being replaced with renewables. This will increase the probability that the ESO will need TO's to provide network solutions/systems to ensure that the network has the Black Start capability in the decarbonised world. This is of concern in Scotland, where the ESO, TOs and Government have been working to establish a new Black Start procedure.

3.1.24 Reactive power is required for voltage control. As the GB energy industry transitions to a greater decentralised and decarbonised electricity system, the ESO has indicated that it needs access to new sources of reactive power. The ESO will test regulated network solutions for reactive power against other commercial options.

g) Drawbacks of proposed mechanism and mitigation

3.1.25 The main drawback is as per the introduction - additional process. In this case this drawback is further mitigated by some of the “more common” operability areas being subject to an automatic volume driver. This avoids the need for additional process. However, for other uncertainty areas like Black Start where the costs could be significant, the additional process is justified.

3.1.26 As noted above for the volume driver, the drawback of any volume driver approach is that the UCA may not accurately reflect the costs. However, to mitigate this, the UCAs are based on historical costs and RIIO-T2 forecasts which provides a high degree of certainty over the costs and embeds RIIO-T1 cost efficiencies. This represents value for money.

h) Value for money and ability to finance

3.1.27 As per the introduction – paragraph 3.18.

3.2 Third Party Driven Need

3.2.1 A key driver of uncertain external costs are decisions by or actions of third parties, hence, not in our direct control. In order to reduce the regulatory burden on Ofgem and transmission owners, we are proposing to group a significant number of these under a single ‘third party driven’ uncertainty mechanism.

3.2.2 The issue and/or risks that are likely to materialise under the third-party reopener are outlined below. The justification for a third-party reopener, including the materiality, frequency and proposed mechanism are also set out below.

a) Issues and risks the mechanism addresses

3.2.3 **Cyber Resilience:** SHE Transmission and the other network companies are becoming increasingly dependent on business IT systems and operational technology. This dependency will only increase as the electricity networks become smarter, more automated and more digitalised. The pace of change also makes it difficult to accurately predict how our cyber resilience will need to evolve.

3.2.4 Over the last decade, cyber-attacks have become more frequent and sophisticated, being used as a means of political statement or terrorist attack. The most obvious example on a network operator in recent years occurred in the Ukraine where a cyber-attack resulted in over 200,000 consumers being left without power. Unless network companies improve their cyber resilience then they will remain at risk of a similar, if not worse, attack.

3.2.5 This significant risk is reiterated by the Government's National Cyber Security Strategy[17]. The Government specifies the minimum requirements for cyber security which all network companies must comply. The need for the significant increase in cyber security investment when compared with the RIIO-T1 period is driven by new regulations and the increasing cyber threat. The Government implemented the new Network and Information Systems (NIS) Regulations in May 2018. They aim to increase the overall level of cyber-security across operators of essential services in the EU. We are working with the NIS Competent Authority (a joint role held by Ofgem and BEIS) to ensure our plans reflect the investment required to meet these new regulations. In addition, new cyber risks and threats may emerge. If they do this will impact our costs during RIIO-T2. We therefore support Ofgem's proposal to introduce a reopener mechanism to adjust our funding during the price control period should things change that are beyond our control.

3.2.6 **Physical Site Security:** As the owner of electricity transmission assets in Great Britain, we are responsible for several assets that are deemed by government as Critical National Infrastructure (CNI). Working with the responsible government department, i.e. BEIS, network operators agree and implement the Physical Security Upgrade Programme (PSUP), which involves measures required to enhance physical security at CNI sites. They advise us on the appropriate security measures we are required to implement. These confidential sites may change over the course of the RIIO-T2 price control which therefore creates uncertainty for both the network companies and consumers, as the network companies will need to recover the costs of upgrading these sites.

3.2.7 Ofgem is proposing to provide baseline allowances for physical security investment mandated by government as it considers there to be enough clarity of government requirements. To deal with the uncertainty, Ofgem is proposing a reopener at both the mid-period and end of the price control to adjust allowed revenues if government mandates changes to the scope of work required during RIIO-T2. We agree with Ofgem's view that a reopener mechanism is appropriate, should there be a need to undertake works during RIIO-T2.

3.2.8 **Legislative, policy or engineering standards changes:** We are governed by legislation and engineering standards when developing our network. We must be able to respond to substantively changed outputs as a direct consequence of changes in legislation, policy and standards in order to meet the needs of consumers and other network users, and in a way that will still allow us to deliver the schemes and projects required and avoid delaying key projects to the detriment of network users and consumers. There is no Mid-Period review which would consider changes to outputs available in RIIO-T2, but a reopener mechanism is proposed to deal with the uncertainty to continue to deliver for consumers.

[17] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/567242/national_cyber_security_strategy_2016.pdf

3.2.9 **Flood Resilience:** The global climate is changing, and in Scotland the amount and intensity of rainfall increasing, along with a trend towards stormier weather and rising sea levels is an uncertainty. This increases the flood risk to areas that are not currently at risk and other areas that are already at risk may see an increase in the severity or frequency of flooding. For our Business Plan, we are proposing flood alleviation works at ten network locations. We are also proposing to maintain our programme of environmental risk assessment accounting for new forecasts and guidance, in line with best practice, using the latest forecasts and climate change projections. Whilst it is possible to propose flood alleviating works at the outset of RIIO-T2, the Scottish Environment Protection Agency (SEPA) frequently reviews its flood risk mapping. New threats can be identified, and network not previously considered to be within a 'high risk' area might become so. If this eventuality occurs, a mechanism is required to accommodate the additional costs during RIIO-T2. We are therefore proposing to introduce a mechanism to adjust our funding during the price control period should our assets require alleviating work to reduce the risk of flooding.

b) Ownership of the risks

3.2.10 Where the costs and level of activity are outside our control it is better to determine cost allowances when the need and associated cost is more certain. To do so prematurely during the price control review can introduce a risk premium as the continued uncertainty may result in consumers paying more than is necessary to efficiently delivery the required output in each of these areas.

3.2.11 **Cyber Resilience:** The risk of cyber-attacks on our network operations has increased significantly since the start of the RIIO-T1 price control and the government has introduced new regulations in relation to cyber resilience which we must comply with. Cyber-attacks place risk on both the consumer and the network companies and could have detrimental impacts to the industry and its consumers, from the leak of customer information, to the potential shutting down the network resulting in black outs. These are risks that we, as the network operator, are best placed to manage because our customers and consumers do not have the ability to manage them.

3.2.12 **Physical Site Security**: CNI are assets identified by the Centre for the Protection of National Infrastructure (CPNI) and BEIS as necessary for the country to function, and therefore likely to be at higher risk of attack with the intention to cause detrimental impacts to the country and the consumers. These are risks that we are best placed to manage because our customers and consumers do not have the ability to manage them. It is up to the network companies to deliver these strategic investment plans and, in the same way as in RIIO-T1, Ofgem will ensure appropriate and proportionate security measures are being put in place and inform where any funding adjustments may be required. There is currently enough clarity of government requirements to allow Ofgem to provide us with baseline allowances for security investment mandated by government. However, the uncertainty surrounds any potential changes to this plan over the course of RIIO-T2 and some form of mechanism needs to be implemented to deal with this risk should it arise.

3.2.13 **Legislative, policy or engineering standards changes:** There is huge uncertainty in the current political climate. Other potential legislative, policy or engineering standards changes which may create uncertainty during the RIIO-T2 period includes: System Operator-Transmission Owner Code (STC), the Energy Code Review, Significant Code Review, the Security and Quality of Supply Standard (SQSS) flood resilience requirements (see below), HSE's Electricity Safety, Quality and Continuity Regulations (ESQCR), and the Energy Data Taskforce data requirements (BEIS).

3.2.14 **Flood Resilience:** The need to respond to updated assessments of flood risk to ensure network resilience lies with us as the TO. It is our responsibility to demonstrate that the scope of any works is necessary and appropriate and that the costs are efficient. The scope of assets considered to be 'at risk' is out with our control, it is therefore better to determine cost allowances when the need and associated cost is more certain. The need to maintain resilience of the network transmission assets has been highlighted during RIIO-T1. The potential for change is high and it is unlikely that the flood risk will decrease over time.

c) The proposed mechanism

3.2.15 We propose a mid and end period reopener, with a materiality threshold of 1% of annual base revenue, to deal with any costs resulting from third party requirements. The reopener will consider any changes in the threat landscape within scope and may adjust allowed revenue either up or down.

3.2.16 The one key addition to this overarching "third party driven" reopener is for the early 2021 reopener for Cyber Resilience as proposed by Ofgem companies who are unable to submit these plans by December 2019. We intend to use the mechanism to submit our baseline RIIO-T2 ex ante allowance ask. Given the pace of change in this area, we believe it should also be subject to the mid-period and end of period windows for this mechanism.

d) Justification for the mechanism

3.2.17 As per the introduction – paragraphs 3.11 to 3.13.

3.2.18 Also, we consider that, as we have no control over the third party driven need to invest in the network, it is reasonable to group these into a single reopener in order to manage the uncertainty appropriately.

d) Materiality of the issue

3.2.19 **Cyber Resilience:** Cyber resilience requirements are likely to increase as the risk of cyber-attacks increases, evolves and becomes more sophisticated and as a result the costs we incur in T2 could potentially increase significantly and therefore a reopener mechanism will be necessary. As noted above, we intend to utilise Ofgem's proposed reopener at the beginning of RIIO-T2.

3.2.20 **Physical Site Security:** As there is currently enough clarity from the government on the required security upgrades, unlike other areas such as cyber security, we hope that the materiality of the issue will be low. However, it is impossible for us to predict the materiality of the issue as the PSUP requirements are mandated by government. To give an indication of the level of expenditure for known schemes, we have two schemes spanning RIIO-T1 and RIIO-T2 costing on average £3m each per price control period (total £12m). However, schemes that may come forward in RIIO-T2 can be entirely different in number and scope.

3.2.21 **Legislative, policy or engineering standards changes:** There is potential for further legislative, policy or engineering changes which may result in a cost for network companies with no associated allowances, again as these are uncertain. It is impossible for us to identify the materiality of the issue.

3.2.22 **Flood Resilience:** The costs currently included within our RIIO-T2 plan are determined to be necessary following latest forecasts and climate change projects and a requirement to address flood risks. There are no costs included for uncertain schemes as the scale of work is dependent on the nature of those affected, and the level of predicted flooding.

f) Frequency and probability of the issue

3.2.23 **Cyber Resilience:** Cyber resilience refers to the measures we take as a network operator to prevent cyber-attacks from occurring. Many cyber-attacks aim to cause disruption such as loss of electricity supply. Effective protection and capability to respond minimises the impact of any incident on consumers. The frequency and probability of the issue is unknown but must be kept under review as business IT systems and operational technology continue to increase as networks become smarter, more automated and more digitised.

3.2.24 **Physical Site Security:** Physical site security refers to the measures we take to prevent physical attacks occurring to some of the most important infrastructure on our network, as identified by government. Physical attacks aim to cause disruption such as loss of electricity supply. Effective protection and capability to respond minimises the impact of any incident on consumers. The frequency and probability of issue is unknown but must be kept under review as the risk and threats of attack may increase depending on a number of external factors. In RIIO-T1, we were instructed by Government to improve the physical site security of two schemes. However, the frequency and probability of such requests is out of our control, and therefore it is impossible for us to forecast the frequency and probability of the issue during RIIO-T2.

3.2.25 **Legislative, policy or engineering standards changes:** Given the current uncertainty around the political landscape in the UK currently there is high potential for network companies to experience unforeseen costs resulting from changes to legislation, policy or engineering standards during the RIIO-T2 price control.

3.2.26 **Flood Resilience:** Information is regularly updated by the Met Office and SEPA but due to the evolving nature of climate change information, the impact is difficult to determine now. We would anticipate frequency and probability of this mechanism being used is high during RIIO-T2. This is as the pace of climate change evolves and ever improved forecasting can anticipate the impacts.

g) Drawbacks of proposed mechanism and mitigation

3.2.27 The main drawback is additional process for network companies to make a reopener submission, for Ofgem to assess the submission and then to make the revenue adjustments. It is mitigated by having a materiality threshold.

h) Value for money and ability to finance

3.2.28 As per the introduction – paragraph 3.18.

3.3 Landowner Compensation

a) Issues and risks the mechanism addresses

3.3.1 In terms of the Electricity Act 1898 ('the Act') we require consent from landowners and occupiers to install our electric lines and associated equipment on, over or under land and these have historically been secured by the industry through wayleave agreements, which are personal agreements and do not run with the land. Whilst there has been a drive in recent years on new capital project to secure these rights by way of permanent agreements, there is a legacy of wayleave agreements for existing infrastructure and indeed in some cases, landowners prefer to receive an annual wayleave payment instead of agreeing to the grant of a permanent right. We also require access to that land for the purposes of inspecting, maintaining or replacing the line or equipment.

3.3.2 We propose a reopener to deal with injurious affection claims (compensation for the reduction in value of the claimant's land as a result of the interference e.g. our assets being on the land), wayleave terminations and challenges to our land rights that landowners may lodge with the business for existing assets.

3.3.3 These claims are inevitable as there is provision under the Act for grantors to terminate wayleave agreements and in the event of the grant of a Necessary Wayleave following a termination, the Act permits the landowner or occupier to submit a claim for losses. The number of claims and quantum of claims are very difficult to forecast. This is a continuation of a RIIO-T1 reopener.

3.3.4 We also understand that a review of Wayleave Compensation Rates has recently been implemented in England and Wales. The National Farmers Union (NFU) has been working closely with the Energy Networks Association (ENA) to ensure farmers are receiving an accurate payment to cover the cost of the interference caused by poles and pylons in fields. It is reasonable to anticipate a similar review taking place in Scotland as rates have not been updated since April 2013 and this may potentially lead to additional claims and/or increased payments.

b) Ownership of the risks

3.3.5 Where the costs and level of activity are out with our control it is preferable to determine cost allowances when the need and associated cost is more certain. As we have noted throughout, to do so prematurely during the price control review can introduce a risk premium.

3.3.6 It is our obligation to ensure that we operate and maintain a safe, secure and resilient network throughout our licences area, this includes ensuring that we have robust land rights. These are risks that we, as the network operator, are best placed to manage because our customers and consumers do not have the ability to manage them.

3.3.7 Efficient land management ensures that costs, budgeting and clean delivery are achieved. Clear negotiation of suitable rights ensures longevity and reduces risk to our assets in the long-term whilst ensuring efficient costs for consumers.

c) The proposed mechanism

3.3.8 The proposed mechanism for wayleaves is a reopener mechanism at both the mid-period and end of the price control, with a materiality threshold of 1% of annual base revenue. This is to adjust allowed revenues to deal with injurious affection claims, loss of development claims, wayleave terminations and challenges to our land rights that landowners may lodge with the business for existing assets. The reopener will consider any changes in the threat landscape within scope and may adjust allowed revenue either up or down.

d) Justification for the mechanism

3.3.9 As per the introduction – paragraphs 3.11 to 3.13.

e) Materiality of the issue

3.3.10 Through the RIIO-T2 period we have a robust strategy for ensuring that, where possible, we secure land rights through the most appropriate mechanism to secure land rights in perpetuity, to make sure that we can develop and operate the network guaranteeing the security of supply without the risk of expensive diversion works if we must reroute the network elsewhere. Our best view based for potential claims in RIIO-T2 is in the region of £30m.

3.3.11 As noted above, the NFU has recently undertaken a review of the advisory wayleave payments working with the ENA giving input on how the advisory arable payments are calculated. This has the potential to add to the materiality of this issue however it is not possible to quantify the impact at this stage.

f) Frequency and probability of the issue

3.3.12 As noted above, claims are inevitable but the number and quantum of claims is very difficult to forecast.

g) Drawbacks of proposed mechanism and mitigation

3.3.13 As per the introduction – paragraphs 3.14 to 3.17.

h) Value for money and ability to finance

3.3.14 As per the introduction – paragraph 3.18.

3.4 Subsea Cables

a) Issues and risks the mechanism addresses

3.4.1 We have two subsea cables on our network, Caithness to Moray and Kintyre to Hunterston, with the potential for that to increase in RIIO-T2. Both are significant and critical assets. Given the planned investment in subsea cables, faults and/or damage in the RIIO-T2 period are unlikely to be any reflection of the asset age or wear and tear. Rather, they will be the result of third-party interference or unforeseen environmental damage, both of which are outside our control and unpredictable. These are known as high impact low probability (HILP) events.

3.4.2 While unlikely, damage, interference and/or cable faults have the potential to be costly and drawn out given the global demand for the vessels, equipment and expertise necessary for their repair and the location of the cables. Neither the need nor the cost is certain enough to accurately forecast an ex ante allowance.

b) Ownership of the risks

3.4.3 It is our obligation to ensure that we operate and maintain a safe, secure and resilient network throughout our licence area, ensuring this through inspection, operating and maintenance expenditure to cover routine maintenance of subsea cables. We take on this business as usual operational risk of sub-sea cables.

3.4.4 However, the ownership of risk for exceptional faults, interference or damage lie with both the network operators and consumers, due to the highly uncertain probability and nature of a subsea event occurring, the ability to mitigate this risk is out with our control.

3.4.5 Subsea cables are designed and installed to deal with known threats, e.g. buried below the seabed in order to minimise the risk of bottom trawling and the fishing exclusions zones which means such events should not occur. Shipping is also excluded from anchoring within cable corridors. However, there is always a risk that such mitigation measures are not followed.

3.4.6 To mitigate the risk of potential cable failure and the associated impact on consumers, we are required to undertake several subsea remotely operated vehicle (ROV) inspections every four years. A ROV is a small submersible craft which performs various underwater tasks in support of a wide range of industries, including oil and gas, scientific exploration, search and salvage, inspection of underwater equipment such as pipelines, surveying and dam inspections. This would identify any potential damage or interference that requires us to act to mitigate potential cable failure.

c) The proposed mechanism

3.4.7 The mechanism we propose for exceptional subsea cable damage, interreference or faults is a reopener mechanism at both the mid-period and end of the price control to adjust allowed revenues with no ex ante baseline allowances.

3.4.8 The reopener would address the uncertainty associated with:

- interference (i.e. third-party shifting rock cover leaving a subsea cable exposed and at higher risk of damage);
- damage (i.e. clear evidence of cable damage which, if left uncorrected, poses additional risk of cable fault); and
- fault (i.e. in the event of a cable fault, we would seek funding for the recovery of the efficient costs associated with rectifying the issue).

d) Justification for the mechanism

3.4.9 As per the introduction – paragraphs 3.11 to 3.13.

3.4.10 Subsea cables are now becoming common place on the transmission system, including those connected as part of the Caithness to Moray HVDC, Kintyre to Hunterston link and the potential Island links. This brings increased costs associated with operating and maintaining these links due to subsea cable monitoring. The business as usual increased costs are included in our baseline but exceptional faults, interference and damage costs are not. Without the reopener mechanism we would need to include baseline expenditure to cover the cost of an exceptional fault, interference or damage to a subsea cable.

e) Materiality of the issue

3.4.11 It is difficult to quantify the materiality on expenditure as there has not been an exceptional fault event in the RIIO-T1 period and therefore no historic costs to benchmark against. However, given the nature of the potential subsea works involved, the global demand for the specialist boats and equipment the cost may be material.

3.4.12 The Kintyre-Hunterston subsea cable is due its first ROV inspection during 2020/21. The follow-up inspection is required during 2024/25. The Caithness-Moray subsea cable is due its first inspection during 2023/24. The cost of these latter ROV inspections during RIIO-T2 are included within our baseline plan. However, the cost of any mitigating works to address the issues identified as a result of the ROV inspection are uncertain and it is not possible to accurately forecast these costs.

f) Frequency and probability of the issue

3.4.13 Given that this proposed reopener is to deal with 'exceptional' faults, which are HILP events, the likelihood of an exceptional fault is low but with a potentially significant impact on both the network and consumers. The potential increase in subsea cables on our network through the RIIO-T2 period does increase the probability.

3.4.14 The mechanism will also allow us to seek funding for the efficient costs associated with taking mitigating action to address damage or interference following each ROV inspection. In doing so, we would seek to provide Ofgem with the necessary technical and engineering justification as to why work is required to address the issue identified through a ROV inspection.

3.4.15 The ROV inspections might uncover subsea cable damage or interference, for which no funding is sought under RIIO-T2. The proposed inspection dates are outlined above. If an ROV inspection identified an issue in relation to a subsea cable (i.e. rock movement, uncovered cable etc increasing the risk of fault), we would seek to utilise this reopener mechanism to fund the efficient cost of mitigating action.

g) Drawbacks of the proposed mechanism and mitigation

3.4.16 As per the introduction – paragraphs 3.14 to 3.17.

h) Value for money and ability to finance

3.4.17 As per the introduction – paragraph 3.18.

3.5 HVDC Centre

a) Issues and risks the mechanism addresses

3.5.1 A successful Network Innovation Competition (NIC), the proposal for a Multi-Terminal Test Environment secured funding in 2014 and the High Voltage Direct Current (HVDC) Centre, based in Cumbernauld, was opened in April 2017.

3.5.2 The HVDC centre enables the planning, development and testing of high voltage direct current transmission solutions in GB. This facility houses a real-time simulator system, IT infrastructure and accommodation for replica HVDC control panels. Using these state-of-the-art simulators, the HVDC Centre can model and resolve potential issues in real-time before they impact on the delivery of other HVDC projects or the wider transmission system.

3.5.3 The requirements associated with the HVDC centre sit within our NIC transmission licence obligation, but it is operated in partnership with National Grid Electricity Transmission, SP Energy Networks and National Grid ESO.

3.5.4 The period 2021-26 will see a huge investment in HVDC in GB; the most concentrated development of HVDC anywhere in the world. Such extensive development poses significant risks to the reliable operation, control and resilience of the GB network unless these risks are managed appropriately.

3.5.5 As the centre moves from a NIC funded project to business as usual, our RIIO-T2 baseline allowance proposals includes annual operating expenditure associated with the HVDC centre. These costs are based on a reasonable expansion to account for highly probable HVDC projects coming forward during the RIIO-T2 period and wishing to be situated at the centre.

3.5.6 However, our assumptions relating to the expansion of the centre under RIIO-T2 is based on a reasonably conservative assumption (in order to protect consumers). If we experience a significant increase in projects that wish to undertake testing at the site, this will lead to the requirement for a larger physical expansion of the HVDC centre and its supporting infrastructure.

3.5.7 We are therefore proposing a RIIO-T2 reopener to cover the potential need for physical expansion and the associated recruitment, to accommodate the additional testing requirements associated with new, innovative and untested HVDC technology anticipated during RIIO-T2 (over and above that accounted for within the baseline operating expenditure and use of NIC funding).

b) Ownership of the risks

3.5.8 Where the costs and level of activity are out with our control it is preferable to determine cost allowances when the need and associated cost is more certain. As we have noted throughout, to do so prematurely during the price control review can introduce a risk premium.

3.5.9 To mitigate the risk associated with an expanding HVDC network in GB, we require an independent testing facility that:

- can host detailed models (and control/protection hardware) from multiple suppliers and from SO/TOs and integrate these together;
- has the expertise (and technology infrastructure) to undertake specialist studies. The specialist studies conducted at the centre now include studies of other forms of convertors (for example Wind Turbines, Statcoms and Static Var Compensation) in combination with HVDC, and analysis of the effect of HVDC on transmission light current systems such as transmission protection hardware which can be integrated into the centres' real-time analysis environment; and
- has credibility so that the results can be relied upon.

3.5.10 The above means that the existing centre space is now being used to capacity.

3.5.11 We consider that the ability to de-risk future HVDC investment is of benefit to both TOs and consumers. The benefits include:

- improving the TOs and ESOs ability to better specify requirements and reduce risk;
- enabling multi-terminal systems to be fully considered rather than the traditional point-to-point;
- better modelling and scenario planning of future network topologies to understand integration and operation between the DC and AC systems;
- encouraging new entrants to the market (by providing the ability to test new solutions and their interoperability);
- reducing costs through enabling competition;
- de-risking HVDC solutions, by testing operational issues that may arise in a simulated DC/AC environment; and
- training staff in the new operational and fault management strategies.

c) The proposed mechanism

3.5.12 The proposed mechanism for HVDC Centre is a mid and end of period reopener, with a materiality threshold of 1% of annual base revenue, to adjust allowed revenues, net of any final determined baseline allowances, for efficient costs associated with the physical expansion of the centre. This expansion is to accommodate additional testing requirements of HVDC circuits out to 2026. The reopener will consider any changes in the future likelihood of HVDC transmission projects within scope and may adjust allowed revenue either up or down.

3.5.13 The mechanism will be dependent on the forthcoming HVDC and other related projects wishing to utilise the HVDC Centre as a testing facility through physical expansion in order to accommodate real-time simulator systems and IT infrastructure and accommodation for replica HVDC control panels. As noted above, a conservative assumption has been made for the RIIO-T2 period but there is potential for increasing number of HVDC projects wishing to utilise the capability of the centre.

3.5.14 Prior to 31 March 2020, we must submit notice to Ofgem setting out our proposal for the future use of the HVDC centre. As part of this, we must explain how the approach will maximise future value to all customer, including those of the other TOs. This will include our assessment of most cost efficient solution to the end consumer and the solution which most effectively addresses the increasing relevance and potential value in the activity of the centre over the period.

3.5.15 Where any potential increased HVDC investment is materialising, we will provide robust justification to Ofgem and the efficient costs incurred with physical expansion of the HVDC Centre will be subject to the reopener as set out above.

d) Justification for the mechanism

3.5.16 In addition to the justification set out within the introduction, to further support the justification for this mechanism, there is a critical need in GB for a facility to support HVDC projects. For example:

- The SO and TOs cannot allow HVDC interconnectors to connect to the Grid unless they are satisfied that their own network protection scheme will not be compromised in high convertor concentrated areas of the GB network where the contribution to network fault level is dominated by HVDC. This can require detailed testing of multiple vendor supplied models together with the dynamic network model and real protection relays.
- We understand from our liaison with HVDC owners, the ESO and TOs, that convertor control interactions have already been evidenced within the GB network. These interactions require specific detailed modelling using models which are fit for this purpose. Neither TOs, the ESO, nor the developers have the ability to analyse the performance of HVDC at this level within the context of the GB network that they are connected.
- The proposed multi-terminal extension of the Caithness-Moray link to Shetland will require testing against the detailed model of the Shetland network to avoid adverse effects on the AC and DC networks.
- New Eastern HVDC interconnector capacity will result in more than 50% of the overall circuit capacity between Scotland and England being HVDC in nature. It is critical that this transmission boundary with a range of known historic stability considerations is tested in sufficient detail with HVDC performance appropriately defined and validated to complement its reinforcement whilst maintaining system security and reliability.

3.5.17 In addition, clear example of the above influencing the scale of centre use includes the Moyle interconnector’s requirement to validate their new control and protection system against detailed models of the AC network to avoid adverse interactions. There are plans to commission replicas at the centre to undertake this validation, ahead of any further changes to technical codes or additional HVDC project connections. We are aware of other new projects with connection activity in the RIIO-T2 period also proposing replica controls that they may seek the centre to host.

3.5.18 There is currently no facility in GB other than the HVDC Centre that is able to undertake this work.

3.5.19 In addition to the likelihood of additional projects coming forward, initial discussions are underway across the industry to mandate the testing and enhanced simulation of HVDC projects wishing to connect to the network. Should the necessary code and licence modifications materialise, there is a high likelihood of additional testing to be undertaken at the HVDC Centre.

e) Materiality of the issue

3.5.20 The next price control period will see the most intensive period of investment in HVDC in GB, with up to 12 new links very likely to be commissioned in this period. Such volume of new schemes within close electric proximity and on an electrically weak network brings significant risks.

3.5.21 Some examples of forthcoming projects areas are:

- **The Shetland island** link extension to the Caithness-Moray project is expected to proceed. Since this will form a multi-terminal, the first of its kind in GB, it has been decided that the testing of the Shetland hardware will be undertaken at the Centre.
- **North Sea Link** interconnector will connect the UK and Norway. It connects directly into the eastern side of the Anglo-Scottish Boundary, which is currently dynamically managed via a parallel Western HVDC link route, a collection of dynamic compensation devices and series compensation devices. It is a boundary subject to well documented stability considerations. NSL will be the world's longest subsea interconnector when operational in 2021 and will need to complement the stability of the Anglo-Scottish boundary with its performance.
- **Aquind interconnector** is expected to commission an HVDC convertor station in Lovedean connecting to France in 2022. This interconnector would complement a nearby HVDC convertor at Chilling near Lovedean (IFA2) undergoing development at present, and contributes to some 7.2GW of HVDC alone connected along the south coast double circuit ring between Lovedean and Kemsley.
- **Dogger Bank offshore windfarm** has situated its converter stations between Beverley and Cottingham, connecting to the substation at Creyke Beck. The project aims to begin commencing construction in 2022 (comprising multiple DC links).
- **Western Isles** embedded link between Arnish Point, Stornoway to Beauly is expected in 2023.
- **NorthConnect** interconnector is expected to commission an HVDC converter station in Peterhead connecting to Norway in 2023/2024.
- **Eastern HVDC** proposes two separate HVDC links, one connecting Peterhead to Hawthorn Pit/ Cottam/Drax commissioned in 2026, and the other connecting Torness with Hawthorn Pit/ Cottam/Drax which will be under construction in 2026.

f) Frequency and probability of the issue

3.5.22 This proposed reopener is designed to address the uncertainty associated with a potential requirement to invest the in physical expansion of the HVDC Centre to accommodate additional testing of new HVDC projects wishing to connect to the GB, and ongoing stress-testing of those currently connected.

3.5.23 As noted above, the period 2021-26 will see a huge investment in HVDC in GB. We therefore consider the probability of the issue arising during the price control as moderate to high. National Grid ESO's Future Energy Scenarios document illustrates a range of total interconnection between GB and external networks ranging between 8-17GW by 2025. The growth in offshore, again as quoted within National Grid ESO's FES, is between 7-27GW up to 2030, where a significant proportion of the overall capacity would be HVDC connected, given the distances involved in these connections. There is not a comparable level of development within a network of equivalent scale to GB.

g) Drawbacks of proposed mechanism and mitigation

3.5.24 As per the introduction – paragraphs 3.14 to 3.17.

h) Value for money and ability to finance

3.5.25 As per the introduction – paragraph 3.18.

3.6 Visual Impact of Scottish Transmission Assets (VISTA)

a) Issues and risks the mechanism addresses

3.6.1 As noted in our VISTA policy[18] we continue to recognise the landscape and visual impacts our existing infrastructure can have on people and the environment. Stakeholders have strongly and consistently told us that they value mitigating the visual impact of our assets, so much so that we will explore options to extend the scheme out with National Parks and National Scenic Areas during RIIO-T2. The extension of the scheme is something we will engage further with our stakeholders on in RIIO-T2.

3.6.2 Stakeholders strongly support the continuation of visual amenity projects. At a workshop in March 2019 the majority of stakeholders felt that we could go further than we set out in our plans for RIIO-T2 in terms of minimising visual impact of our infrastructure.[19] At an earlier workshop in November 2018, when asked to vote on whether Ofgem's VISTA fund should be extended into RIIO-T2, the majority agreed. Almost half of those who participated voted 10/10 in agreement.

3.6.3 The RIIO-T1 price control includes a provision for the electricity transmission owners to reduce the effects of pre-existing transmission infrastructure on the visual amenity of National Parks, Areas of Outstanding Natural Beauty and National Scenic Areas. For SHE Transmission, this is known as VISTA.

[18] SUPPORTING DOCUMENT 24: Visual Impact of Scottish Transmission Assets (VISTA) – Our Approach for RIIO-T2, found here: https://www.ssen-transmission.co.uk/riio-t2-plan/vista-our-approach-for-riio-t2/

[19] At a stakeholder event in March 2019, when asked if our future position on landscape and visual amenity goes far enough on a scale of 1 to 10 with 1 being that it should remain as it is now and 10 should go even further, the average rating was 6.2.

3.6.4 We are supporting the continuation of this scheme throughout RIIO-T2 to appropriately manage the funding associated with mitigating the impact of pre-existing transmission infrastructure.

b) Ownership of the risks

3.6.5 Through VISTA, we aim to reduce adverse landscape and visual impacts associated with some of this infrastructure, and where possible enhance Scotland's natural and cultural heritage as a result. There are no immediate risks to the TO or consumers as a result of VISTA, but through engagement and consultation with stakeholders, we are able to identify to gather feedback on those projects which are seen to have most benefit.

3.6.6 There are strict criteria that proposed VISTA projects must satisfy in order to qualify for consideration as part of Ofgem's incentive. We will continue to take full account of these through consultation, assessment and project selection, allowing for identification of projects that deliver the best enhancement of visual amenity. Regard must also be had to our licence obligations under the Electricity Act, the most relevant of these being a duty to maintain our network in an economical and efficient way; having regard to the preservation of amenity; and having regard to the conservation and enhancement of the natural beauty, wildlife and cultural heritage of the National Parks and National Scenic Area.

c) The proposed mechanism

3.6.7 Ofgem confirmed in May 2019[20] an intention to retain the scheme to mitigate visual impact of pre-existing transmission infrastructure. In addition, it has identified proposed modifications to the regulatory approval process for smaller scale, non-technical projects (such as landscaping, tree planting and other enhancement activities) in that we will be allocated 2.5% of the overall fund. We support both proposals for RIIO-T2.

3.6.8 We also support the continuation of the current regulatory arrangements and approval criteria for proposals to reduce the impact of pre-existing transmission infrastructure on the visual amenity of National Parks and National Scenic Areas.

d) Justification for the mechanism

3.6.9 This is an area that Ofgem recognise is supported by stakeholders and one is which funding should only be released when it has been subject to detailed and sufficient stakeholder review, need assessment and cost assessment on a bespoke project by project basis.

e) Materiality of the issue

3.6.10 During RIIO-T2 we will engage continuously with stakeholders to identify and then develop further technical schemes within National Parks and National Scenic Areas (including those which impact on the

[20] https://www.ofgem.gov.uk/publications-and-updates/riio-2-sector-specific-methodology-decision

setting of such designated sites). An initial review has identified several potential undergrounding projects.[21] Collectively if these go ahead, we could underground a minimum of 12.5km. The final length is subject to further stakeholder engagement, the outcome of our optioneering and Ofgem approval. It is provided as an illustration of our ambition to build on the successes of RIIO-T1. This initial current list of visual amenity projects in no way limits or prohibits further projects being considered during the period.

3.6.11 Other potential schemes have also been identified for further stakeholder consultation, but these are still at an early stage of development and are also subject to wider network considerations. Including at Fort William (undergrounding 3.5km of a single circuit 132kV OHL and Skye (undergrounding of a single circuit 132kV trident line).

f) Frequency and probability of the issue

3.6.12 We anticipate a similar of level of activity during RIIO-T2 as experienced during RIIO-T1. We will engage with Ofgem and stakeholders throughout the price control in order to provide foresight of potential schemes considered eligible for VISTA funding.

g) Drawbacks of proposed mechanism and mitigation

3.6.13 As per the introduction – paragraph 3.14 to 3.17. It is an also area that has significant support from stakeholders and is valued by consumers so any additional process is far outweighed by the value it delivers.

h) Value for money and ability to finance

3.6.14 As per the introduction – paragraph 3.18.

3.7 Brexit import charges

a) Issues and risks the mechanism addresses

3.7.1 The UK is due to leave the European Union (EU) on 31 January 2020. A Brexit deal has been agreed in principle with the EU however both the United Kingdom (UK) and the EU need to approve and sign the withdrawal agreement. They will then start to negotiate new arrangements and a transition period to prepare for new rules.

[21] Glen Strathfarrar (Undergrounding 3.5km of single circuit 132kV on the Beauly-Deanie circuit – 33kV strung on other side); Killin (undergrounding 9km of a double circuit 132kV OHL and a single circuit 132kV OHL - 33kV strung on other side).

3.7.2 This could lead to significant changes to import charges and other cost drivers for transmission owners. The potential impact of Brexit on costs is uncertain as we draft our Business Plan and costs are submitted based on current import charges and other cost drivers.

3.7.3 We can be exposed to costs not accounted for in our ex ante allowances to account for it ex ante may result in an unnecessary and high-risk premium. Between January 2020 and the start of the RIIO-T2 price control in April 2021, the impact Brexit will have on import charges is likely to be clearer (provided the UK does leave the EU). We are proposing a mechanism whereby any unforeseen impact on import charges can be reflected in our final allowances subject to an independent assessment, prior to Ofgem Final Determinations.

b) Ownership of the risks

3.7.4 Whilst we, as a responsible business, can seek to mitigate the potential impacts of Brexit in order to protect consumers, there are elements of this impact which are out with our control.

3.7.5 Where the costs and level of activity are outside our control it is better to determine cost allowances when the need and associated cost is more certain.

c) The proposed mechanism

3.7.6 The proposed mechanism for Brexit is an annual and end of period reopener to adjust allowed revenues to deal with import and export tariff changes, with the materiality threshold set at 1% of annual base revenue. We will only be able to apply where it is able to demonstrate that an adjustment to external costs (i.e. import tariffs) has a direct impact on the costs of sourcing goods from the EU.

d) Justification for the mechanism

3.7.7 As per the introduction – paragraph 3.11 to 3.13.

3.7.8 The basis of a Brexit reopener is predicated on changes to import and export tariffs caused by changes in trading rules with the EU and other countries where our supply chain sources equipment. The future trading arrangements with countries within the EU are completely out with our control and an annual reopener window is required to mitigate the potential impact. This will ensure that new and changing trade rules including tariffs on imports is available for additional expenditure compared to the status quo.

e) Materiality of the issue

3.7.9 The materiality of this issue is unknown until such point the UK's exit from the EU is agreed. However, we anticipate a different trading relationship with other EU members could lead to increased tariffs.

3.7.10 There is also a risk of government-imposed trade tariffs as has been experienced in other countries globally (such as those between the United States and China). These can happen without warning and on a scale that it is impossible to estimate. This further demonstrates a risk to UK TOs that cannot be reasonably mitigated as it is completely out with our control.

f) Frequency and probability of the issue

3.7.11 As with many issues relating to Brexit, the impact and probability of potential changes to the UK's trading relationship with the EU is currently unknown. It is therefore difficult to forecast the frequency against which this reopener will be utilised. However, we anticipate that any changes to the existing arrangements will have a material impact and must be accounted for within the RIIO-T2 uncertainty framework.

g) Drawbacks of the proposed mechanism and mitigation

3.7.12 As per the introduction – paragraph 3.14 to 3.17.

h) Value for money and ability to finance

3.7.13 As per the introduction – paragraph 3.18.

3.8 Whole System Coordinated Adjustment

a) Issues and risks the mechanism addresses

3.8.1 The mechanism will work cohesively to improve whole system planning and operation, improve support for new whole system approaches to ensure the price control is not a barrier to the efficient allocation of projects across networks. It would be triggered by two or more cooperating networks. A single network could also trigger the mechanism if they were able to meet the threshold requirements. This protects consumers, only funding network companies where whole systems approaches and benefits are demonstrable. We support this while advocating expansion as set out in our Whole System Mechanism (see Appendix 3 of our Regulatory Framework: Output, Incentives, CVP and Innovation[22]).

3.8.2 In order for us to safely and efficiently operate a co-ordinated and economical system of electricity transmission. The mechanism will work cohesively to improve whole system planning and operation, improve support for new whole system approaches to ensure the price control is not a barrier to the efficient allocation of projects across networks. It would be triggered by two or more cooperating networks. A single network could also trigger the mechanism if they were able to meet the threshold requirements. This protects consumers, only funding network companies where whole systems approaches, and benefits are demonstrable. We support this.

[22] SUPPORTING DOCUMENT 12A: Regulatory Framework - Outputs, Incentives, Consumer Value Proposition and Innovation, found here: https://www.ssen-transmission.co.uk/riio-t2-plan/regulatory-framework-outputs-incentives-and-innovation/

b) Ownership of the risks

3.8.3 The concept of whole-system solutions is still in its infancy and therefore many whole-system outcomes are uncertain and could be subject to change due to circumstances and/or information, or also due to the different timings of the electricity distribution price control.

3.8.4 Where the costs for each party are uncertain, a reopener mechanism is required to protect consumer interests by supporting the reallocation of project revenues and responsibilities to the relevant network owner(s).

3.8.5 The ownership of the risk lies with the network operators. It is up to the network operators and wider industry parties to work together in order to identify and then deliver whole system solutions. The price control itself should not act as a barrier to the efficient allocation of projects across networks.

c) The proposed mechanism

3.8.6 Ofgem will develop and implement a whole system reopener, referred to as 'Coordinated Adjustment Mechanism', which will protect consumer interests by supporting the reallocation of project revenues and responsibilities to us, as the relevant network owner.

3.8.7 Unlike some of the other reopener mechanisms, this mechanism will not allow for new funding, instead this reopener mechanism will allow for the realignment of revenues and responsibilities of projects where doing so is in the interests of consumers. The projects should already have ex ante funding or reopener mechanisms in place from other areas, such as load related expenditure or non-load related expenditure, and therefore the CAM reopener focusses on the realignment of revenues and responsibilities of projects rather than providing new funding.

3.8.8 However, to trigger CAM, the network is required to provide evidence that the overall value of the project meets a pre-specified threshold of £20m (to sufficiently justify the administrative cost) and can only be triggered within specific windows during the price control period. It is widely accepted at this stage that many whole system outcomes are uncertain and could change due to circumstances and/or information. This 'unknown' could lead to uncertainty and a lack of progress in developing whole system outcomes that do not meet the relevant thresholds required to trigger CAM.

d) Justification for the mechanism

3.8.9 The appropriate reallocation of revenues and responsibilities will improve in-period cooperation and make the price controls more resilient to changes arising from the energy system transition. However, the mechanism must be designed such that it cost-effectively achieves appropriate reallocations.

3.8.10 To help balance the needs of flexibility and certainty, Ofgem is designing threshold requirements to ensure focus on projects that will produce the most value for consumers at reasonable administrative cost.

3.8.11 It is better to reallocate project revenues and responsibilities to the relevant network owner when the need and associated costs for the relevant network owners is more certain. This reopener mechanism will allow network companies to deal with changes within the price control which could not be assumed or forecasted at the outset. These changes could lead to considerable investment and the reopener mechanism can reallocate the project revenues and responsibilities to the relevant network owner.

e) Materiality of the issue

3.8.12 The concept of whole-system solutions is still in its infancy and the definition and clarity of what is expected is still being developed by Ofgem. The idea of whole system thinking has only been developed during the RIIO-T1 price control period and no direct expenditure has been incurred in RIIO-T1. It is very difficult for us to predict the materiality of the issue for the RIIO-T2 period.

f) Frequency and probability of the issue

3.8.13 It is widely accepted at this stage that many whole system outcomes are uncertain and could change due to circumstances and/or information, or also as a result of different timings of the electricity distribution price control. This 'unknown' could lead to uncertainty. Therefore, it is likely for this issue to occur over the RIIO-T2 period and there will be a need for the reallocation of project revenues and responsibilities for network companies.

g) Drawbacks of the proposed mechanism and mitigation

3.8.14 Additional process for network companies to make a reopener submission, for Ofgem to assess the submission and then to make the revenue adjustments.

3.8.15 The drawbacks are minimal. As whole system thinking is still in its infancy, it is essential that there is flexibility in the price control to allow network companies to work together and deliver the most optimal solution for the customer ensuring that the relevant network company is allocated the correct revenues and responsibilities.

3.8.16 This reopener mechanism should only have a positive impact on consumers. This mechanism is simply encouraging network companies to work together to identify the most economical solution for the consumer and ensuring that the revenues and responsibilities can be allocated to the correct network owner.

g) Value for money and ability to finance

3.8.17 On balance, the appropriate reallocation of revenues and responsibilities will improve in-period cooperation and make the price controls more resilient to changes arising from the energy transition. There is a clear need to ensure that the mechanism must be designed to ensure it cost-effectively achieves appropriate reallocations. The mechanism will help ensure that the most optimal solution for both the company and for consumers balancing risk, process, keeping costs down, and funding only when the need is more certain.

4 Pass-through items (non-controllable costs)

a) Issues and risks the mechanism addresses

4.1.1 Non-controllable costs are cost items over which we have no control. Examples include adjustments for business rates and tax[23] that we cannot influence. We believe it is appropriate to maintain the current RIIO-T1 pass-through arrangements for business rates.

b) Ownership of the risks

4.1.2 Ownership of this risk cannot sit with either consumers or the TO due to the nature of the costs within scope. Business rates are uncontrollable costs and as such no risk ownership can be applied.

c) The proposed mechanism

4.1.3 The mechanism would see a continuation of the approach adopted under RIIO-T1 with Allowed Revenue being updated as part of the Ofgem's Annual Iteration Process (AIP) to take into account non-controllable costs.

d) Justification for the mechanism

4.1.4 As noted above, we have no control over business rates. We believe it is appropriate that these costs a recovered through our Allowed Revenue.

e) Materiality of the issue

4.1.5 Business rates are estimated to be £326m over RIIO-T2.

f) Frequency and probability of the issue

4.1.6 Pass-through costs will definitely be incurred.

g) Drawbacks of proposed mechanism and mitigation

4.1.7 There are limited drawbacks. We can't influence these costs so have no ability to increase efficiency and therefore they are automatic to keep the admin negligible.

h) Value for money and ability to finance

4.1.8 As above, we can't influence the efficiency but can't be expected to finance.

[23] Tax is covered in our Section 7: Financing our Plan of the Business Plan.

Appendix 1: Snapshot tables for Uncertainty Mechanisms

In support of our overall Business Plan submission, and as required by the Business Plan guidance, we have completed the following snapshot tables in the excel workbook "Snapshot Table Uncertainty Mechanisms".

Appendix 2: Volume Driver Detail

Recap of RIIO-T1 volume driver mechanism

A2.1 In RIIO-T1, allowances were granted for sole and shared use schemes in accordance with the Baseline Generation Connection Outputs and Generation Connections Volume Driver mechanism license condition (Special Condition 6F). Allowances were based upon a defined output, either MW or MVA, associated with specific developments. £/MW and £/MVA UCAs were used to determine ex ante allowances for sole use and shared use infrastructure as outlined in Table A2.1 RIIO-T1 volume driver

A2.2 .

A2.3 Other rates were set for the delivery of additional connections above the defined MW/MVA ex ante outputs, and for the delivery of "atypical projects" which have particularly high costs. For atypical schemes, 50% of the allowance was based on the atypical rate, and 50% on the actual cost. All schemes that fall under the RIIO-T1 volume driver are also subject to the TOTEX incentive mechanism using a 50% sharing factor.

A2.4 In RIIO-T1, costs associated with new OFTO connection infrastructure costs were recovered from an ex ante allowance for delivery of four schemes that were identified in our baseline business plan.

A2.5 For demand schemes, infrastructure costs were recovered from an ex ante allowance for delivery of one scheme identified in our baseline business plan.

Table A2.1 RIIO-T1 volume driver

2009/10 prices	Sole use	Shared use
Ex ante allowance	£99m	£83m
Ex ante output	1,168MW	1,006MVA
Volume driver for defined T1 ex ante output	£85,000/MW	£83,000/MVA
Volume driver for additional output	£75,000/MW	£83,000/MVA
Atypical project rate*	£294,000/MW	£182,000/MVA

**for atypical projects, 50% of the output was based on the atypical rate, and 50% actual cost*

Design of RIIO-T2 Volume Driver

RIIO-T2 Volume Driver design process

Key lessons Learned & opportunities from RIIO-T1 volume driver

A2.6 Before designing our RIIO-T2 volume driver mechanism, we collected the lessons learned from the application of the RIIO-T1 volume driver from across our business. One of the prominent themes in the feedback received related to the variability in allowances. Although Special License Condition 6F proved to be a successful mechanism for recovering the uncertain costs, the difference between allowances and costs at a scheme level has been variable i.e. there was limited cost reflectivity.

A2.7 However, it was acknowledged the aggregated £/MW and £/MVA UCAs did provide us with flexibility to deliver the most economic and efficient solution, as it wasn't overly prescriptive. Other factors for consideration in our approach for RIIO-T2, as already mentioned, included the significant change in scope and mix of schemes included within our baseline allowance within the RIIO-T1 period. Therefore, the following criteria was considered in our design of our RIIO-T2 volume driver mechanism:

- the mechanism should deliver improved cost reflectivity on a scheme by scheme basis;
- be pragmatic with clear definitions and easily understood, and limited in number and complexity where possible;
- be informed by experience from the RIIO-T1 period, especially cost drivers and associated trends;
- be robustly tested against projected RIIO-T2 schemes (taking into consideration that relative maturity of these schemes); and
- be robustly tested and verified via key stakeholders that have detailed knowledge of the associated complexities.

A2.8 As part of our RIIO-T2 Business Plan, we have outlined our Consumer Value Proposition (CVP) which details how we have gone above and beyond the strict criteria and minimum standards set by Ofgem. A key element of our CVP relates to delivering cost efficiency throughout the RIIO-T2 period. The volume driver will play a key role in this, as the UCAs that underpin our proposed approach for RIIO-T2 are informed by RIIO-T1 costs, which have built in embedded cost efficiencies. The use of actual historical costs to inform RIIO-T2 volume driver UCAs should ultimately maximise cost reflectivity and reduce the risk for consumers of windfall gains for us.

A2.9 Maximising cost reflectivity, in our view, means designing an approach whereby the difference between the total allowance minus costs across a portfolio of projects is as close to zero as possible. Methods of measuring cost reflectivity include calculating the "error" (i.e. difference between total costs and total allowances; this should be as close to zero as possible), and carrying out regression analysis on allowances against cost, aiming for r^2 value close to 1[24]. Using historical costs as the basis of our approach removes the risk of consumers overpaying for new infrastructure. An alternative approach would be to base UCAs on forecast costs for uncertain RIIO-T2 investments. We want to avoid this; we know from experience that these costs are unreliable which could result in consumers being overcharged.

[24] The r^2 value, which is statistical measurement of how close the data fits the line of best fit, can be used as an indicator of how effective the regression is. An r^2 value of 1 would indicate 100% of the data points can be explained by the model, (i.e. for the purpose of our analysis, the output would be directly correlated with cost and actuals would be the same as allowances, and if the r^2 is 0.50, half of the variability in outputs (actual costs) can be explained by the model's inputs (allowances), indicating that only some of the data points can be explained by the model's parameters.

Review of RIIO-T1 performance

A2.10 To inform our approach to designing the RIIO-T2 volume driver, we carried out a review of our performance in RIIO-T1 against the UCAs set at the start of the price control. By calculating the average £/MW and £/MVA for Sole and Shared Use schemes, based on actual and remaining forecast costs for the final two years of the price control period, we were able to establish our performance against the UCAs set.

A2.11 The results of our analysis show that we will outperform against allowed UCAs for both sole and shared use schemes. For typical sole use schemes, we anticipate outperformance of around 15% against the UCA set (this includes crossover schemes which are based on forecasted costs). For atypical sole use schemes, we anticipate outperforming by 24%, and for typical shared use, ~10%.

Table A2.2 RIIO-T1 volume driver performance

SOLE USE Total actual expenditure	**Actual** average UCA 18/19	**Actual** average UCA 09/10	**T1 Licence Conditions** UCA 09/10	**% difference (Actual vs. T1)**
Typical	0.102	0.077	**0.085**	-9%
Atypical	0.293	0.223	**0.294**	-24%
Typical (incl crossover)	*0.095*	*0.072*	***0.085***	*-15%*

SHARED USE Total actual expenditure	**Actual** average UCA 18/19	**Actual** average UCA 09/10	**T1 Licence Conditions** UCA 09/10	**% difference (Actual vs. T1)**
Typical*	0.097	0.074	**0.083**	-11%
Typical + crossover	*0.098*	0.075	**0.083**	-10%

** there were no a-typical Shared Use schemes in T1*

A2.12 The use of single aggregated UCAs for sole and shared use in RIIO-T1 led to large swings in recovery against allowances. In some cases, we experienced significant under/over performance. Such windfall gains and losses has led us to question the cost reflectivity of the single aggregated approach. To assess this, we carried out the following regression analysis on the following:

- Actual costs versus output to determine the effectiveness of using MW and MVA as cost drivers (Figure A2.1 and A2.2); and
- Actuals costs versus allowances to test cost reflectivity for sole use projects, shared use projects and across whole portfolio of sole and shared use (Figure A2.3, 2.4, 2.5).

A2.13 Looking at sole use, the regression for the MW cost driver has an r^2 of 0.530, indicating it has little relevance in explaining costs. When assessing cost reflectivity and comparing actuals against allowances for sole, the r^2 is 0.566, signalling low cost reflectivity. There is also an estimated error of £30m, which is equivalent of 19% of total spend.

A2.14 For shared use schemes, an r^2 of 0.702 on the MVA cost driver demonstrates this is a better cost driver than MW. An r^2 of 0.654 for actuals versus allowances implies higher cost reflectivity for Shared Use schemes, however total error is estimated at £77m, which is equivalent to 17% of total spend.

A2.15 Looking at sole and shared use schemes together, shows an overall portfolio r^2 of 0.755 based upon the UCAs set at the start of the price control, with a total error of £107m (17% of total spend).

A2.16 The trends observed align with our knowledge of our network; for sole use schemes, the correlation between output (MW) and cost is more variable using an aggregated UCA, given the ranges in linear elements and level of substation works needed. This has therefore resulted in windfall gains and losses against allowances. For shared use, there is a stronger relationship between output delivered (MVA) and cost, albeit there is still a significant error term.

Figure A2.1 RIIO-T1 Sole Use MW cost driver assessment

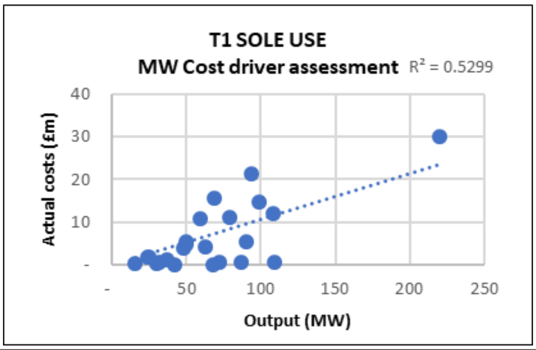


Figure A2.2 RIIO-T1 Shared Use MVA cost driver assessment

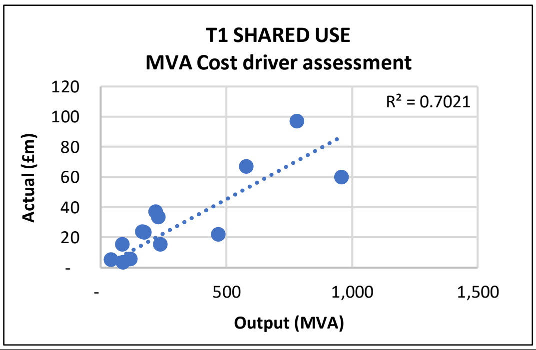


Figure A2.3 RIIO-T1 Sole Use cost reflectivity & estimated error value

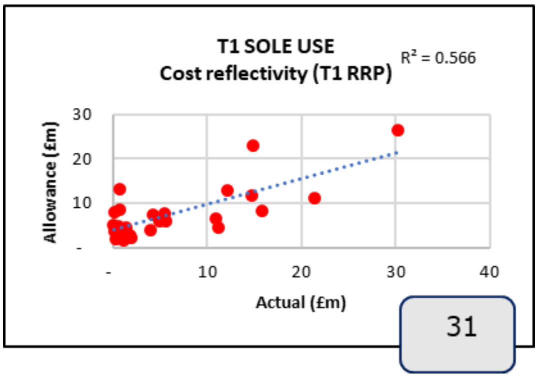


Figure A2.4 RIIO-T1 Shared Use cost reflectivity & estimated error value

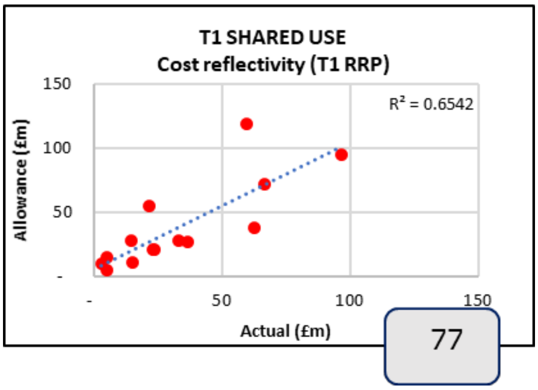
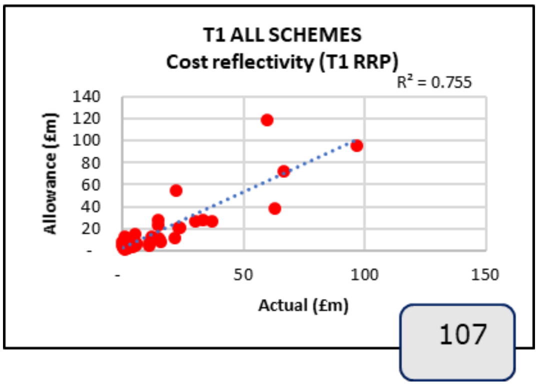


Figure A2.5 RIIO T1 cost reflectivity & estimated error value (sole & shared use projects)



A2.17 Another lesson learned from RIIO-T1 relates to our delivery for both OFTO and demand schemes. In RIIO-T1, the actual delivered works was significantly different to the scope set out in our baseline plan. This meant variances in spend against our ex ante allowances in both categories. In the case of OFTOs, we could be connecting substantial MWs, but for minimal works.

A2.18 Likewise, for demand schemes, whereby a simple in-situ GSP upgrade is required, we recovered costs associated with the additional MW capacity available at the GSP for minimal works. For these types of schemes, we experienced large gains, which we do not deem cost reflective, nor good value for the consumer.

A2.19 In light of this divergence in recovery for these scheme types, we carried out a broad review of all sole and shared use infrastructure delivered in RIIO-T1 under the volume driver. We confirmed that in the round, the scope of works for new sole use connections and shared use schemes involve the same elements and breakdown of works. Typically, sole and shared use schemes involve the following:

- **Transformer Substation** – installation of additional transformer capacity on our network, including all of the ancillary works associated with the installation (e.g. civil works, landing gantries, associated switchgear, protection etc)
- **Switching Station** – installation of new switchgear to accommodate new connections, including all of the ancillary works associated with the installation (e.g. civil works, landing gantries/tower modifications, protection etc)
- **Linear infrastructure** – overhead lines (new or reconductoring existing), underground cables, subsea cabling[25].

A2.20 Our review of RIIO-T1 concluded that our approach in RIIO-T2 should:

- provide improved cost reflectivity; and
- consider a more disaggregated approach due to the similarities of scope, and the need for more appropriate mechanisms to accommodate OFTO and demand schemes.

Options considered for RIIO-T2

A2.21 It is highly unlikely that the trends of infrastructure works required to connect new generators (sole use) and to reinforce the network (shared use) will change dramatically in the RIIO-T2 period. Fundamental changes in the reliance of the wider GB energy system on the transmission network will have to take place before the scopes of sole/shared use schemes, and our project development strategies are modified. This, coupled with the low level of cost reflectivity of the single aggregated approach in RIIO-T1, led us to investigate the application of a more disaggregated approach in the RIIO-T2 volume driver.

A2.22 By a more disaggregated approach, we mean breaking out the large standard infrastructure elements and applying separate UCAs for these (e.g. applying separate rates for linear assets via a £/circuit km, or a £/MVA for transformer substation). We considered different levels of disaggregation, as well as continuing to assess applying a single rate for sole and shared use schemes, as used in RIIO-T1. The alternative options considered during our design phase are summarised below:

- **Option 1 -** High Level Aggregated approach, based on £/MW Sole Use & £/MVA Shared Use, as used during RIIO-T1;

[25] Although not used in RIIO-T1, could be required in RIIO-T2 pending approval of Island link schemes.

- **Option 2 –** Level 1 Disaggregated approach, based on a unit rate for linear infrastructure and £/MW and £/MVA for all other infrastructure;
- **Option 3 –** Level 2 Disaggregated approach, based on a unit rate for linear infrastructure and unit rate recovery for all other switching and transformer substation elements.

A2.23 For options 2 & 3, our design has also considered common variants for determining unit rates for linear assets – e.g. consideration of the level of disaggregation of overhead line types (steel towers, wood pole, composite towers, reconductoring) and voltage levels (132kV, 275kV & 400kV). Our data set for underground cable works (including subsea cables) is limited and as such further work will be required to determine our final approach for recovery of underground elements, we believe this is an issue across all three TO's and a joint study is proposed to provide guidance on a common approach that can be adopted.

Options Review

A2.24 Our review of each option considered several factors as part of the process for determining our approach for RIIO-T2. Considering the key criteria set, we carried out an assessment of the different options against RIIO-T1 costs and some of our RIIO-T2 projects[26] . We also considered feedback from stakeholder engagement sessions with internal departments, external consultants, Ofgem and other the other TOs.

A2.25 In the assessment of each of the alternative options, we considered the use of Monte Carlo simulation analysis to further validate cost reflectivity across the different approaches/options. Regardless of which subset of contracted projects end up getting built, which is what the Monte Carlo analysis simulation would derive, the total allowance should closely match total cost, especially when applying a more disaggregated, cost reflective approach. Therefore, after discussion with external consultants, we felt the use of Monte Carol analysis was unnecessarily due to the linear property of expected values.

A2.26 In our assessment of the alternative options, we considered the cost reflectivity via the following parameters:

- R^2 of the regression for estimated allowances vs. actual/forecasted costs; and
- The error term (i.e. difference between estimated allowance and actual/forecasted costs).

A2.27 We also considered the technical feasibility and practicality of applying the different approaches. This was carried out through numerous internal peer review sessions with System Planning and Investment, Commercial and Project Development teams. These teams were consulted throughout the design

[26] Note that for RIIO-T2, the projects align with our likely view, and does include some uncertain schemes, however any results associated with this dataset should be treated with caution due to the considerable immaturity of costs

process to ensure that the options were accurately and objectively assessed, and that the final proposal was realistically deliverable.

Option 1 (High Level Aggregated approach)

A2.28 Using actual outturn RIIO-T1 UCAs, as shown in Table A2.2, we tested the cost reflectivity by mapping calculated allowances against actual and forecast costs, and calculated the error term. Figure A2.6 shows there is little improvement in cost reflectivity for RIIO-T1 projects as the r^2 is similar to that seen when applying the original RIIO-T1 unit rates. When assessing the dataset on a scheme by scheme basis, large gains and losses are still being made using the single, aggregated UCA rates, as shown in the min and max error delta values in Table A2.3. Significant losses would be made against RIIO-T1 projects (-£109m, 12% of actual/remaining forecasted costs).

A2.29 Such variation was also evident when applying the rates to a selection of our RIIO-T2 projects, where there is a significant overall error term of £120m (28% of forecast costs). However, looking at RIIO-T1 and our likely and uncertain RIIO-T2 investments together resulted in a much lower error value (£10m, 1% actuals/forecasts), however large swings in costs are still present.

Figure A2.6 Option1 cost reflectivity regression graphs and error value

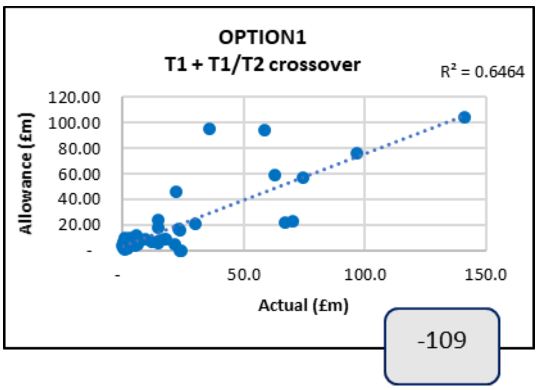


Figure A2.7 Option1 cost reflectivity regression graphs and error value

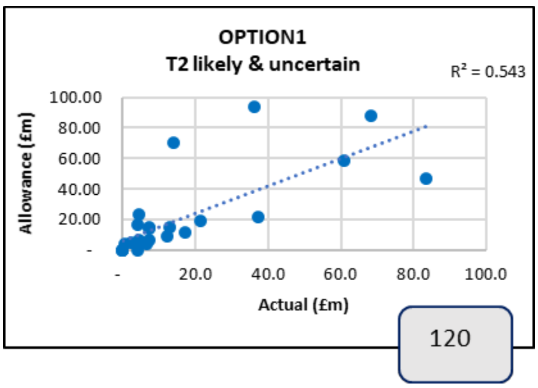


Figure A2.8 Option1 cost reflectivity regression graphs and error value

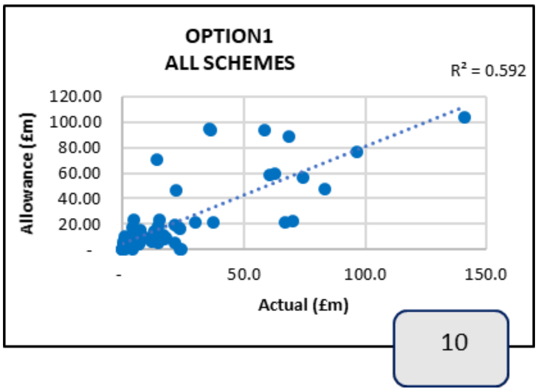


Table A2.3 Option1 cost reflectivity regression and error analysis results

	RIIO-T1 Projects	RIIO-T2 Projects	RIIO-T1 & RIIO-T2
R^2 *(allowances compared to actual/ forecast costs)*	**0.646**	**0.543**	**0.592**
Min error £m	-48	-36	-48
Max error £m	59	58	59
Average error £m	-3	5	0
Error £m (% of total expenditure)	**-109 (-12%)**	**120 (28%)**	**10 (1%)**

A2.30 Despite the low error term when looking at RIIO-T1 and RIIO-T2 projects combined, we need to consider the immaturity of RIIO-T2 costs, so our focus for cost reflectivity and validity of the approach needs to be focused on our RIIO-T1 projects given their cost and output certainty. Also, the error value should be considered alongside the r^2, which for option 1 is deemed low across all project combinations. In light of this, our overall conclusion for this option was that it was not cost reflective and supports our view to consider more disaggregated approaches. Other reasons for discounting the continued use of a single aggregated rate include:

- complications associated with applying the rules for this approach consistently across a wide range of configurations (e.g. OFTOs and demand schemes, issues surrounding the recovery of lower output schemes including GSP connections);
- challenges in dealing with atypical, high value schemes, which were subject to different UCAs and recovery treatment in RIIO-T1. Looking ahead to RIIO-T2, there is a limited dataset of atypical schemes from RIIO-T1 to base rates on. Also, given the nature of atypical schemes that usually involve the installation of non-standard infrastructure (reactive compensation), or the upgrade of established infrastructure at significant expense, it's unlikely single £/MW and £/MVA are the appropriate mechanisms for recovery; and
- feedback from stakeholders including Ofgem, especially in relation to applying a more cost reflective approach, and the experiences from the other TOs as we all applied different approaches in RIIO-T1, of varying levels of complexity.

Option 2 (Level 1 Disaggregated approach)

A2.31 The next option we considered looked at applying a more disaggregated approach whereby we would have separate recovery mechanisms for sole and shared use substation related infrastructure, recovered via £/MW and £/MVA, and £/circuit km for all linear assets.

	Sole Use recovery	Shared Use recovery
Equation	£/MW + £/cct km OHL, UGC, Sub Sea	£/MVA + £/cct km OHL, UGC, Sub Sea
Substation recovery	Proposed RIIO-T2 *UCA* = ***£[redacted] /MW*** £/MW covers costs associated with switching substation works (includes transformers for Sole Use schemes, where required). UCA was derived from averaging actual £/MW across RIIO-T1 sole use substation costs. (It was not possible to use regression to determine £/MW rate; r^2 value as shown in Figure A2.10 is negative)	Proposed RIIO-T2 *UCA* = ***£[redacted] /MVA*** £/MVA covers costs associated with transformer substation works for Shared Use schemes. UCA derived from linear regression analysis based on substation costs for all RIIO-T1 Shared Use projects where transformer substation was installed. (R^2 0.917)
Linear assets recovery (same rates apply to both sole and shared use)	£/circuit km UCAs used to recover costs for: OHL new build by applying different unit cost allowances for: 132kv wood pole at **£[redacted] /circuit km** 132kv Steel Towers at **£[redacted] /circuit km** 275/400kv Steel Towers **£[redacted] /circuit km** OHL reconductoring by applying one rate across all voltages at **£[redacted] /circuit km** UGC by applying one rate across all voltages **£[redacted] /circuit km** SS by applying one rate across all voltages **£[redacted] /circuit km** UCAs for unit rates are based upon extensive historical analysis of our RIIO-T1 scheme expenditures.	

Figure A2.9 Option 2 RIIO-T1 £/MVA transformer substation regression

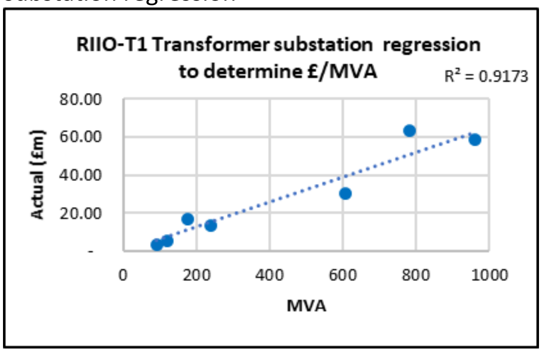


Figure A2.10 Option 2 RIIO-T1 £/MW switching substation regression

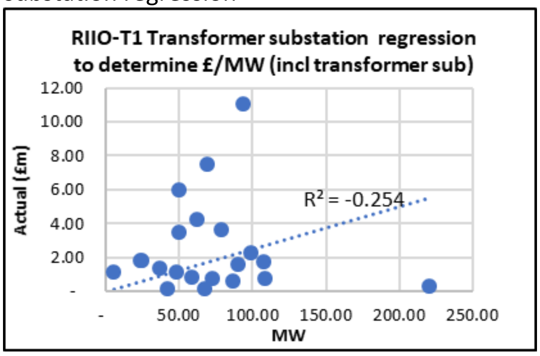


Figure A2.11 Option2 cost reflectivity regression graphs and error value

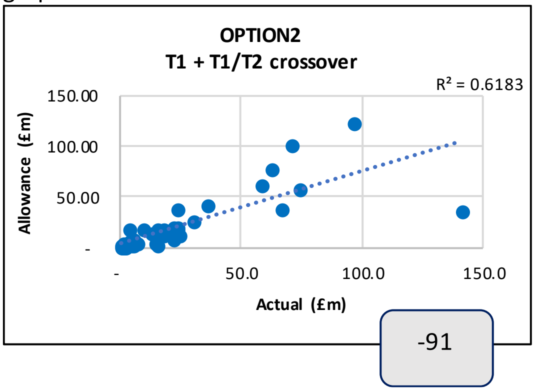


Figure A2.12 Option2 cost reflectivity regression graphs and error value

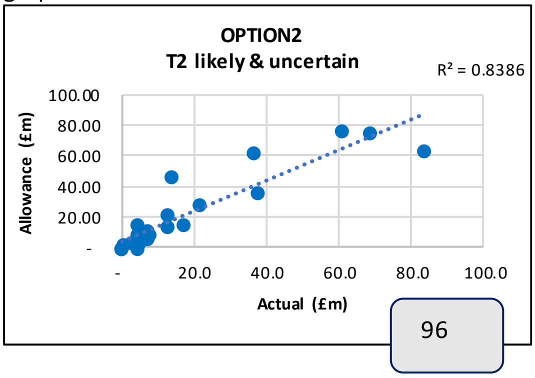


Figure A2.13 Option2 cost reflectivity regression graphs and error value

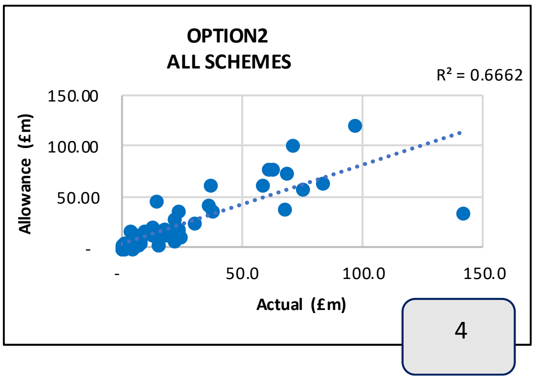


Table A2.4 Option2 cost reflectivity regression and error analysis results

	RIIO-T1 Projects	RIIO-T2 Projects	RIIO-T1 & RIIO-T2
R^2 *(allowances compared to actual/ forecast costs)*	**0.618**	**0.834**	**0.666**
Min error £m	-105	-20	-105
Max error £m	32	33	33
Average error £m	-2	4	0
Error £m (% of total expenditure)	**-91 (-10%)**	**96 (23%)**	**4 (0%)**

A2.32 Our conclusions for this option are set out below:

- Overall, this approach results in comparable cost reflectivity to option 1, based on the r2 values, however there are marginally better error values overall;
- Large swings in recovery remain, as shown from the difference in max and min error values, and for demand schemes, the £/MW will still result in over recovery; and

- The approaches to determining the £/MW and £/MVA values are mathematically inconsistent with the £/MW being derived from an average, and £/MVA from regression.

Option 3 (Level 2 Disaggregated approach)

A2.33 Our approach for this option considered two variants:

A2.34 **Option 3a** was based on recovery of the switching elements using a £/MW, with an atypical threshold triggered where an additional £/bay would be applied for higher value schemes, a £/MVA for transformer substation works and a £/circuit km for all linear assets (same approach for linear as applied in option 2)

A2.35 **Option 3b** was based on using a £/bay for new build/extension works for switching elements, a £/MVA for transformer substation works, and a £/circuit km for all linear assets (same approach for linear as applied in option 2)

A2.36 For switching elements recovery in option 3, we define a "bay" as the works associated with installing or changing one interrupting device e.g. circuit breaker, circuit switcher. The scope of this will vary across schemes but has been assessed on the basis the unit cost will cover all costs associated with the interrupting device including all ancillary works (civil works, associated disconnectors, CT's, CVT's, protection etc)

A2.37 For transformer substation related recovery, unlike option 2, the £/MVA for option 3 is based upon a regression of only projects where a transformer substation was installed. This is a smaller dataset than used for option2, where all projects that involved a transformer being installed were used, which in most cases will have included associated switchgear within the transformer substation. To avoid duplication in recovery of switchgear assets, the smaller dataset is used for option 3.

A2.38 For switching substation related works, the £/MW is based upon an average rate calculated only using projects where switching station works were carried out; projects with transformer elements were removed. This was to avoid duplication in recovery for transformer related works already recovered under the £/MVA rate.

Option 3a

	Sole Use recovery & Shared Use recovery
Equation	£/MW + £/MVA + £/cct km OHL, UGC, Sub Sea + £/Bay
£/MW element	Proposed RIIO-T2 *UCA =* ***£[redacted]/MW*** £/MW covers costs associated with switching substation works (excludes transformer). UCA was derived from averaging actual £/MW across RIIO-T1 sole use switching substation costs. (It was not possible to use regression to determine £/MW rate; r^2 value as shown is negative)

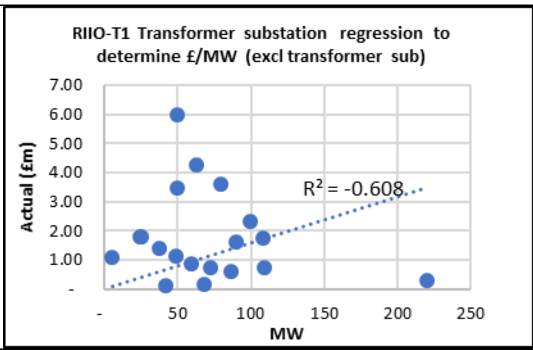
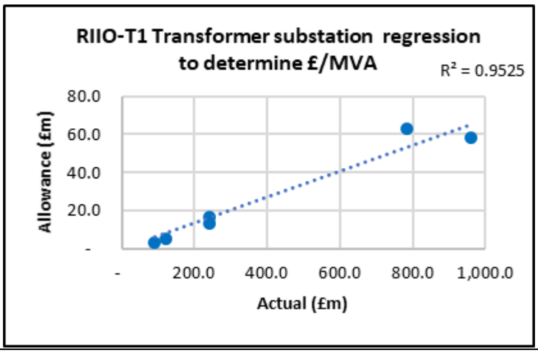
	
£/MVA element	Proposed RIIO-T2 UCA = ***£[redacted] /MVA*** £/MVA covers costs associated with transformer substation works for Shared Use schemes. UCA derived from linear regression analysis based on substation costs for all RIIO-T1 Shared Use projects where transformer substation was installed. (R^2 0.953) 
Linear assets recovery (same rates apply to both sole and shared use)	£/circuit km UCAs used to recover costs for: OHL new build by applying different unit cost allowances for: 132kv wood pole at £[redacted] /circuit km 132kv Steel Towers at £[redacted] /circuit km 275/400kv Steel Towers £[redacted] /circuit km OHL reconductoring by applying one rate across all voltages at £[redacted] /circuit km UGC by applying one rate across all voltages £[redacted] /circuit km SS by applying one rate across all voltages £[redacted] /circuit km UCAs for unit rates are based upon extensive historical analysis of our RIIO-T1 scheme expenditures.
£/bay element	Additional bay cost to cover additional switching infrastructure for both sole and shared use. The trigger for additional bay costs is arbitrary, currently set at £[redacted] /MW for sole use, and where there are more than three bays for shared use schemes. There are concerns here around setting the conditions for when the additional bay rate would be triggered, and despite widely consulting on this we have been unbale to finalise a position on the triggers. To protect consumers against over recovery for demand schemes and simple GSP upgrades, a separate £/bay rate has been established for these scheme types. The proposed recovery rates for £/bay would be for different voltages as below: 132kv £/bay - **£**[redacted] 275kv £/bay - **£**[redacted] 400kv £/bay - **£**[redacted] In-situ bay upgrade - **£**[redacted] UCAs for unit rates are based upon extensive historical analysis of our RIIO-T1 scheme expenditures.

Figure A2.14 Option 3a cost reflectivity regression graphs and error value

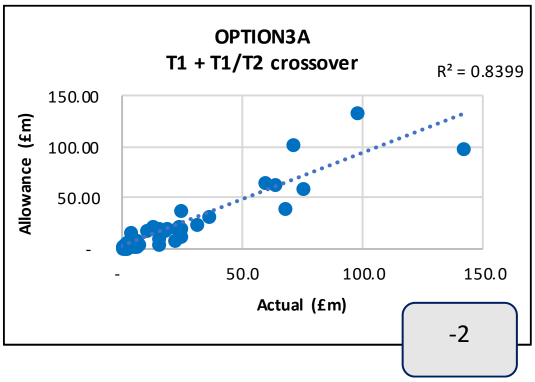


Figure A2.15 Option 3a cost reflectivity regression graphs and error value

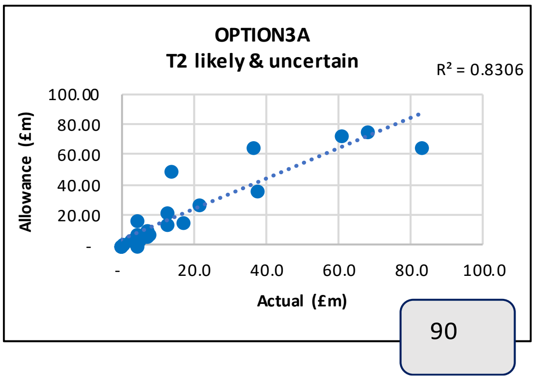


Figure A2.16 Option 3a cost reflectivity regression graphs and error value

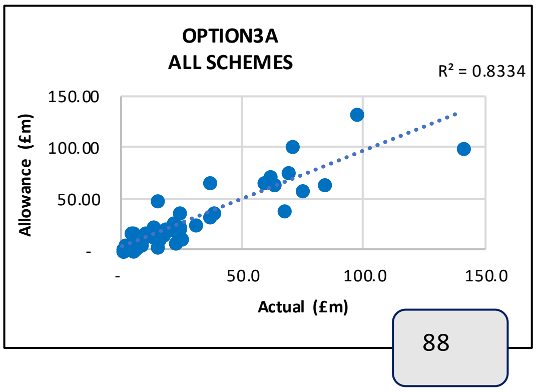


Table A2.5 Option 3a cost reflectivity regression and error analysis results

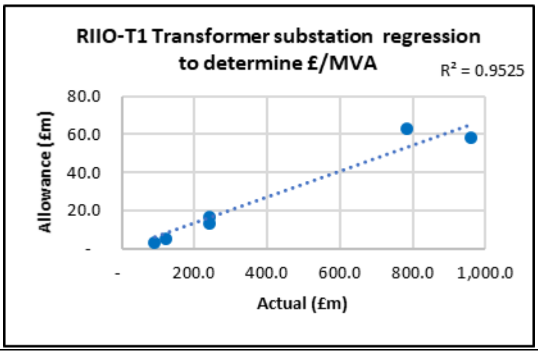
	RIIO-T1 Projects	RIIO-T2 Projects	RIIO-T1 & RIIO-T2
R^2 *(allowances compared to actual/ forecast costs)*	**0.840**	**0.831**	**0.833**
Min error £m	-42	-18	-42
Max error £m	37	35	37
Average error £m	0	3	1
Error £m (% of total expenditure)	**-2 (0%)**	**90 (7%)**	**88 (6%)**

A2.39 Our overall conclusions for this option are set out below:

- This approach results in high r^2 in the regression analysis across all project combinations. Compared to option 1 and 2, there is less of a range between the min and max allowances, and the overall error term is less than 10%. For demand schemes and GSP upgrades, the lower £/bay rate protects against over recovery.

- The trigger point for the additional bay element is difficult to calculate and evidence – separate triggers would apply for sole and shares use. This adds complexity to this option, which we believe would in reality be too subjective and difficult to apply.
- Similar to Option 2, the approaches to determining the £/MW and £/MVA values are mathematically inconsistent with the £/MW being derived from an average, and £/MVA from regression.
- This option does have higher error term overall in comparison to Options 2, however we believe this will be being driven by the immaturity of our RIIO-T2 costs.

Option 3b

	Sole Use recovery & Shared Use recovery
Equation	£/Bay + £/MVA + £/cct km OHL, UGC, Sub Sea
£/bay element	Covers costs associated with connection switchgear substation related elements, whereby the proposed recovery rates for £/bay would be for different voltages as below. To protect consumers against over recovery for demand schemes and simple GSP upgrades, a separate £/bay rate has been established for these scheme types. 132kv £/bay - **£**[redacted] 275kv £/bay - **£**[redacted] 400kv £/bay - **£**[redacted] In-situ bay upgrade - **£**[redacted] UCAs for unit rates are based upon extensive historical analysis of our RIIO-T1 scheme expenditures.
£/MVA element	Proposed RIIO-T2 UCA = ***£***[redacted] ***/MVA*** £/MVA covers costs associated with transformer substation works for Shared Use schemes. UCA derived from linear regression analysis based on substation costs for all RIIO-T1 Shared Use projects where transformer substation was installed. (R^2 0.953) 
Linear assets recovery (same rates apply to both sole and shared use)	£/circuit km UCAs used to recover costs for: OHL new build by applying different unit cost allowances for: 132kv wood pole at **£**[redacted] **/circuit km** 132kv Steel Towers at **£**[redacted] **/circuit km**

	275/400kv Steel Towers £[redacted] **/circuit km** OHL reconductoring by applying one rate across all voltages at £[redacted] **/circuit km** UGC by applying one rate across all voltages £[redacted] **/circuit km** SS by applying one rate across all voltages £[redacted] **/circuit km** UCAs for unit rates are based upon extensive historical analysis of our RIIO-T1 scheme expenditures.

Figure A2.17 Option 3b cost reflectivity regression graphs and error value

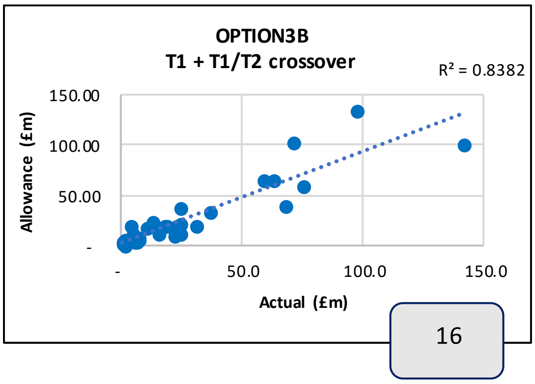


Figure A2.18 Option 3b cost reflectivity regression graphs and error value

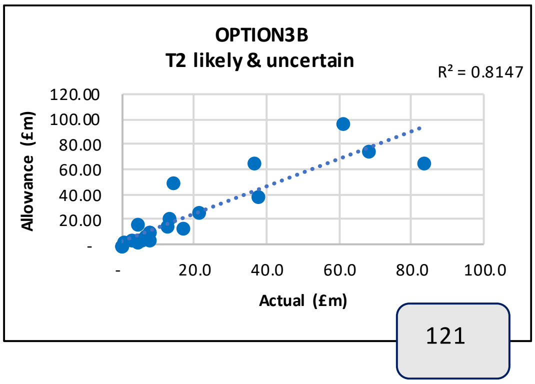


Figure A2.19 Option 3b cost reflectivity regression graphs and error value

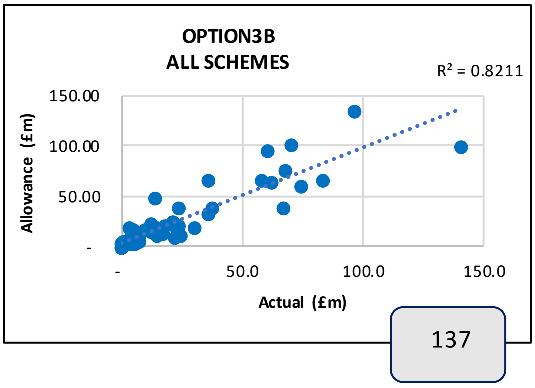


Table A2.6 Option 3b cost reflectivity regression and error analysis results

	RIIO-T1 Projects	RIIO-T2 Projects	RIIO-T1 & RIIO-T2
R^2 ***(allowances compared to actual/ forecast costs)***	**0.838**	**0.815**	**0.821**
Min error £m	-41	-18	-41
Max error £m	37	35	37
Average error £m	0	5	2
Error £m (% of total expenditure)	**16 (1%)**	**121 (9%)**	**137 (10%)**

A2.40 Our overall conclusions for this option are set out below:

- Similar levels of cost reflectivity to option 3b. For demand schemes and GSP upgrades, the lower £/bay rate protects against over recovery. Additionally, in relation to OFTOs, whereby we could be connecting large MW generators for minimal bays works, this approach would allow reflective recovery of these costs.
- In comparison to Option 3a, 3b provides a simpler approach as there is no complications for setting triggers for additional £/bay rates – this is mitigated through the £/per bay unit cost covering all switchgear, allowing accurate recovery of switchgear elements for shared use schemes.
- In terms of internal peer review and consultation, this was deemed the most technically workable and practical approach. However, some concerns were raised as the £/bay cost may restrict the ability to recover costs for elements of connection that emerge but do not fall into the bay definition. Teams found it difficult to define what these elements were, but these would most likely fall into the High Value Projects reopener.
- This option does have higher error term overall in comparison to Options 2 and 3b, however we believe this will be being driven by the immaturity of our RIIO-T2 costs.

RIIO-T2 volume driver proposal

A2.41 We have concluded Option 3b is the best approach as it delivers cost reflectivity, as seen through the comparatively lower windfall gains/losses via the min, max and average error terms. This option also has high r^2 for a selection of our RIIO-T2 likely outturn and contracted projects, alongside our estimated recovery on RIIO-T1. Our conclusion has been influenced by the following:

- Our analysis supports a move to a more disaggregated approach. We can clearly demonstrate that Level 2 disaggregated approaches (3a and 3b) provide a higher degree of cost reflectivity, leading us to discount Options 1 and 2 as credible options. Due to the immaturity of RIIO-T2 scheme costs, our focus remains on ensuring the approach returns cost reflective allowances for RIIO-T1 schemes.
- For simple and straightforward demand schemes and GSP upgrades, the lower £/bay rate protects against over recovery. Additionally, in relation to OFTOs, whereby we could be connecting large MW generators for minimal bays works, this approach would allow reflective recovery of these costs via the £/bay rate.
- Option 3a has been discounted on the basis it is considerably more complex than the other options and would be more onerous to apply in the RIIO-T2 period, without commensurately greater benefit. This complexity relates to:

- o the reliance on arbitrary triggers for an additional bay costs to cover additional switching infrastructure for sole and shared use schemes. Despite widely consulting on this internally, we have been unable to finalise a position on these triggers.
- o The mathematically inconsistent approach to determining the £/MW (via average rate) and £/MVA (via regression analysis). An average rate is considered subjective, with linear regression being the favoured approach, however given the lack of a credible relationship between MW and cost this was not available.

- Overall, option 3b provides the most robust cost reflectivity when assessed against certain sensitivities, namely around varying project configurations. It delivers a high degree of flexibility for a wide range of scheme scenarios and provides a robust platform to cover onshore and offshore generation as well as demand schemes. Additionally, in terms of internal peer review and consultation, this was deemed the most technically workable and practical approach. The bay recovery approach for switching infrastructure also removes the requirement for separate treatment for high value, atypical schemes as project element costs are more reflectively recovered via tailored UCAs.

Table A2.7 Option cost reflectivity comparison – RIIO-T1 & T1/T2 crossover schemes

RIIO T1 and T1/T2 crossover schemes	Option1	Option2	Option3a	Option3b
R^2 *(allowances compared to actual/ forecast costs)*	**0.646**	**0.618**	**0.840**	**0.838**
Min error £m	-48	-105	-42	-41
Max error £m	59	32	37	37
Average error £m	-3	-2	0	0
Error £m (% of total expenditure)	**-109 (-12%)**	**-91 (-10%)**	**-2 (0%)**	**16 (1%)**

Table A2.8 Option cost reflectivity comparison – RIIO-T2 schemes

RIIO T2 schemes	Option1	Option2	Option3a	Option3b
R^2 *(allowances compared to actual/ forecast costs)*	**0.543**	**0.834**	**0.831**	**0.815**
Min error £m	-36	-20	-18	-18
Max error £m	58	33	35	35
Average error £m	5	4	3	5
Error £m (% of total expenditure)	**120 (28%)**	**96 (23%)**	**90 (21%)**	**121 (29%)**

Table A2.9 Option cost reflectivity comparison – RIIO-T1 & T2 schemes

RIIO-T1 and RIIO-T2 schemes	Option1	Option2	Option3a	Option3b
R^2 *(allowances compared to actual/ forecast costs)*	**0.592**	**0.666**	**0.833**	**0.821**
Min error £m	-48	-105	-42	-41
Max error £m	59	33	37	37
Average error £m	0	0	1	2
Error £m (% of total expenditure)	**10 (1%)**	**4 (0%)**	**88 (6%)**	**137 (10%)**

High Value Projects and the RIIO-T2 volume driver

Volume Driver - High Value Elements

A2.42 Given our experience through RIIO-T1, we encountered projects that required non-standard assets or works in order to connect generators or create capacity. Some of these elements were large reactive power compensators, such as Stronlairg windfarm requiring 2 Static Compensators (Stat Com), other examples are a large amount of protection work required to connect generators that does not fall under the more disaggregated volume driver approach.

A2.43 Option 3b largely removes the need for separate treatment for atypical schemes. However, there may be projects that for several reasons, such as regional/site specific factors, non-standard assets or network configuration requirements, the whole project is unsuitable to be funded through the volume driver mechanism. These schemes will be put forward for funding via the annual High Value Transmission Project (HVTP) reopener when certain triggers are met.

A2.44 For entire schemes to be considered for the HVTP reopener, as outlined in Section 2.3, there would be two threshold criteria – the project value must be greater than £25m and the forecast unit costs are at least a third higher than the volume driver unit cost allowance.

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