Draft Determination
Redacted
NGET Draft Determination Response to ET Annex

As a part of the NGET Draft Determination Response

nationalgrid

Contents

Introduction

Whilst we share Ofgem's objectives for RIIO2, the Draft Determination (DD) for NGET as it stands is unacceptable because it fails to meet the needs of current and future consumers as well as the needs of our direct customers and broader stakeholder base. This is because the package as a whole reduces network reliability and resilience, jeopardises the pace of delivery of a net zero energy system, and erodes regulatory stability and investor confidence in the sector.

We welcome the fact that Ofgem has clearly signalled this as a consultation in which it is open to making changes based on stakeholder views and through consideration of new evidence. We note that on a number of topics Ofgem has specifically acknowledged that it is open to better options being brought forward, and potential weaknesses in current proposals. This is positive and important because we consider that a significant number of proposals are currently unacceptable and remedies are necessary for Final Determination to address serious issues identified.

We will continue to engage constructively with Ofgem and all stakeholders over the coming weeks to provide robust evidence and rationale to motivate and secure the necessary changes for Final Determination.

Navigating our response

There are eight parts to our overall response in which we provide the substantial evidence to justify and support the changes needed:

1. A short covering letter for GEMA
2. An executive summary of our response
3. A summary of key issues and proposed remedies
4. Our response to Ofgem's core DD document questions
5. **Our response to Ofgem's Electricity Transmission sector document questions**
6. Our response to Ofgem's NGET-specific document questions
7. Our response to Ofgem's Network Asset Risk Metric (NARM) document questions
8. Our response to Ofgem's Finance document questions

This document is part 5 of our overall response and provides a summary, in one place, of the major proposals across the suite of Ofgem's DD consultation documentation that are currently unacceptable to us with significant remedies necessary.

Quality of service – setting outputs for RIIO-ET2

Incentives not covered by questions

Ofgem does not ask any questions on the overall package of incentives or on a number of specific incentives such as energy not supplied. Before we answer ETQ1 we provide our response to the DD proposals in those areas.

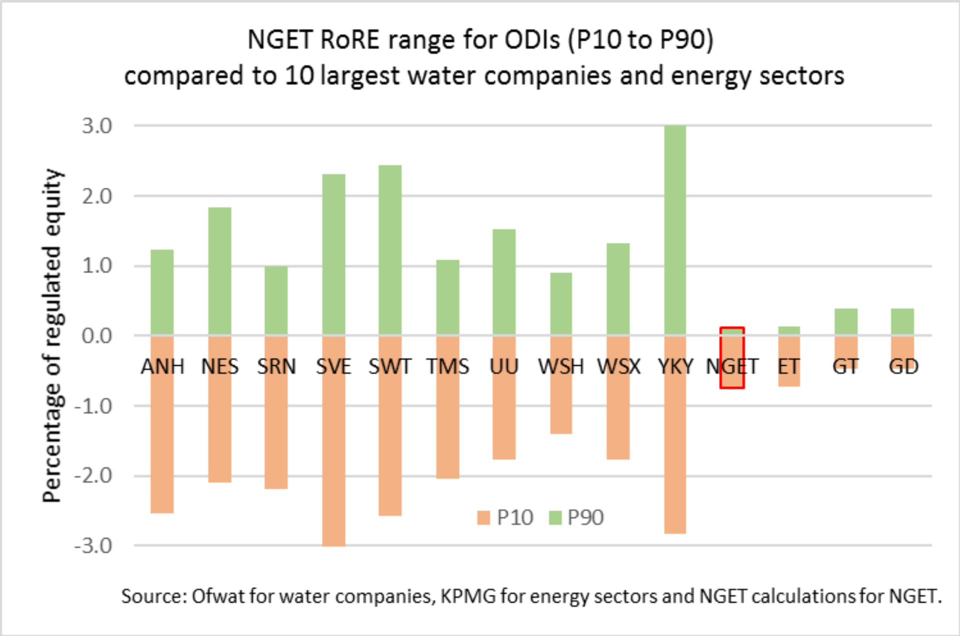
Overall package of output incentives

The DD proposes an incentive package for NGET that is skewed towards penalties and ex-post clawback and away from incentives to deliver for consumers. This matters for consumers because it strongly encourages us to focus on low-risk, cautious investments to avoid penalties and discourages us from innovating and seeking new efficiencies because they will not be rewarded for the risk we'll be taking.

The DD's proposes ex post reviews of outputs if a company delivers anything different from what is in its business plan and to enable this introduces the concept of "secondary deliverables" that was not in the RIIO-2 methodology. The ex post reviews strongly discourage companies from taking innovative approaches because if they do, they risk Ofgem reducing their allowances if, with the benefit of hindsight, it disagrees that the approach was innovative or efficient. The lack of clarity around how these ex post reviews will work in the DD compounds the disincentive to innovate.

The figure below shows that the incentives linked to service performance are much weaker in the energy sector compared with the water sector, even though PR19 for water was a very tough price review. In addition, the electricity transmission sector has weaker positive incentives than the gas transmission or gas distribution sector.

NGET RoRE range for ODIs compared with water and the other energy sectors



Ofgem has rejected our incentives around accelerating low-carbon connections and savings consumers money through providing innovative, flexible services to the ESO even though they were supported by stakeholders. If Ofgem approved these at the FD it would deliver benefits for consumers and move our incentive package towards symmetry.

Remedies needed for ODIs:

- Increase the size of the upside for the overall package of ODIs to incentivise us to deliver service improvements for current and future consumers.
- Approve our ODIs on accelerating low-carbon connections and savings consumers money through providing innovative, flexible services to the ESO.
- Adjust the common ODIs so that the incentive ranges are more symmetric.

Energy not supplied
Ofgem has not asked a question about energy not supplied (ENS), so we are addressing this incentive here.

Target
Ofgem's proposed ENS target of 145 MWh is far too low given the 80% reduction in our asset health expenditure Ofgem has proposed for NGET in its DD. Ofgem should revert to the ENS target we proposed in our business plan of 175 MWh, which is a 45% improvement in our ENS target compared with our current RIIO-1 target of 316MWh. Ours was the largest proposed improvement in the ENS target of any TO in their business plans. Our business plan target of 175 MWh was predicated on Ofgem allowing us the asset health expenditure in our business plan. Therefore if Ofgem moves to 175 MWh for our ENS target in its FD, as we suggest, this target will be even more

stretching for us than we expected it to be when we submitted our business plan and will represent a very good outcome for our customers and consumers.

Collar
Ofgem's proposed collar of 3% of our base revenue for ENS is far too high for the T2 period. We propose the collar should be 0.5% of our base revenue for the following reasons.

First, Ofgem set the 3% of base revenue collar for the T1 period on the basis that ENS events are high-impact and low-probability events. Ofgem's logic was that during an 8-year price control period a TO should be able to offset the impact of a large one-off penalty that hit the collar through rewards earned during the rest of the period. Because the T2 period is only 5 years long there is less time for TOs to offset the penalties generated by large one-off events. Therefore, Ofgem should lower the collar to 5 years / 8 years x 3% = 1.875%.

Second, Ofgem's DD proposes cutting our asset health expenditure by 80% compared with our business plan and by 70% compared with our annual T1 expenditure on asset health. Ofgem must recognise that this will have an effect on the probability of large ENS events and reduce the ENS collar further from 1.875% to 0.5%. This will also have the effect of making the overall ODI package more symmetric and less skewed towards penalties.

Voll incentive rate
We agree with Ofgem's proposal to keep the existing value of lost load (VoLL) and update it for inflation for the RIIO-2 period. We think the update for inflation should be to 2019-20 prices.

We disagree with Ofgem's proposal to allow Ofgem to amend the VoLL during RIIO-2, to reflect any recent studies. Ofgem's review of recent studies in paragraphs 2.17 to 2.20 of the DD ET sector document concluded that no change to VoLL is needed (apart from uplifting for inflation). Ofgem did not revise the VoLL during the 8-year T1 price control period and your recent review of studies shows that is still remains about right. Therefore, there is no need to introduce uncertainty about this incentive rate, which will dampen the incentive on TOs to deliver for consumers because they will not know what level of investment will be covered by the rewards (or avoided penalties) under ENS.

ENS incentive methodology statement
We can update our ENS incentive methodology statement and submit it to Ofgem by 31 December 2020 as proposed in the DD, although in recent discussions Ofgem has suggested it might be able to be flexible on this date depending on how busy Ofgem and TOs are with finalising RIIO-2 at the time.

We disagree with Ofgem's proposal that the updated ENS incentive methodology statement should include:

> "tangible commitments (including milestones and key deliverables) to develop and implement in RIIO-T3 a methodology that takes account of embedded generation in the ENS metric" (paragraph 2.28)

This is because in Ofgem also states:

> "We instead propose to establish an industry working group (including TOs, DNOs, ESO, ENA) to develop a methodology, including any necessary assumptions, for accounting for embedded generation in RIIO-T3. We expect TOs to test and refine that methodology in the last two years of RIIO-2." (paragraph 2.26)

We do not think it is sensible for TOs to include commitments to including embedded generation in the ENS metric in their methodology statement by 31 December 2020 because the industry working group has not yet been set up and we would be pre-empting its work.

Insulation and interruption gases (IIGs) leakage incentive

Ofgem has not asked a question about the insulation and interruption gases (IIGs) leakage incentive, so we are addressing Ofgem's DD proposals here. We propose that you drop the IIGs leakage incentive for NGET as we explain below.

Overlap with our proposed SF_6 removal PCD proposal

We have been in constructive discussions with Ofgem about a PCD for schemes to remove SF_6 from our network and we submitted our proposal on August 2020. Ofgem said in its DD that, based on the potential overlap between this proposal and the IIGs leakage incentive, Ofgem will "make a decision at Final Determinations on whether to continue to apply the IIG ODI to NGET" (paragraph 2.69, DD NGET annex). We propose that you drop the IIGs leakage incentive for NGET to avoid any overlap with our PCD, which covers overall abatement for the long-term benefit of consumers.

Target

While we propose Ofgem drops the IIGs leakage incentive for NGET, in case Ofgem does not we have a comment on the target. In its DD Ofgem has proposed a new target for the IIGs leakage incentive of a 15% reduction compared with the average leakage rate between 2013/14 and 2019/20 for each network company. Ofgem's proposal is different from, and much tougher than, the three options Ofgem proposed in its SSMD. Ofgem acknowledges this point in paragraph 2.127 of the DD ET sector document. We propose that Ofgem returns to the options in paragraph 3.165 of its sector-specific methodology decision in the SSMD and uses: "The average of leaked IIG emissions from the final three years of RIIO-ET1". This method for setting the target avoids the risk of using one year's data, which could be an outlier, but has the advantage compared with using all 8 years of T1 data that it reflects TOs' most recent performance.

IIGs incentive Methodology Statement

We propose that we drop the IIGs leakage incentive for NGET. If Ofgem agrees it would be helpful if Ofgem can give us early confirmation of this so that we do not have to update our IIGs incentive Methodology Statement and submit it to Ofgem by 31 December 2020.

Stakeholder survey for New Transmission infrastructure projects

Ofgem has not asked a question about the Stakeholder survey for New Transmission infrastructure projects, so we are addressing Ofgem's DD proposal here.

We agree with Ofgem's three main proposals for this incentive:

- It will be a reputational incentive;
- A licence condition is not required; and
- TOs will report on feedback received from the survey and how they intend to act, if at all, via their User Groups and publicly on their website, where appropriate.

Timely connections

Ofgem has not asked a question about the timely connections incentive, so we are addressing Ofgem's DD proposal here.

This penalty-only incentive on connections offers should be balanced with a reward-only incentive to accelerate low-carbon connections (see our answer to NGETQ3), which will encourage us to innovate to find new ways of delivering low-carbon connections more quickly.

Ofgem has not mentioned how the penalty rate for this incentive will be calculated in the DD, but we understand from the draft licence condition it will be: untimely offers / total offers x 0.5% of base revenue, as it is in the RIIO-1 period for SPT and SHE-T. We support keeping this penalty rate calculation and Ofgem has not proposed changing it.

Stakeholder engagement ODIs
Ofgem has not asked a question about stakeholder engagement incentives in its DD, so we are addressing this incentive here.

In the core DD document Ofgem says "4.40 Having assessed the companies' bespoke output proposals, no comparable performance metrics, which can appropriately monitor performance across all the companies, were identified. As such, we are not proposing to include a common ODI-R in this area. Our decisions on the bespoke output proposals are set out in the company annexes."

We could not find any assessment of our proposed approach to stakeholder engagement ODIs in the DD NGET annex or the DD ET sector annex. We set out our approach to stakeholder satisfaction / engagement incentives on page 25 of our NGET RIIO-2 business plan and pages 30-31 of our NGET RIIO-2 business plan ODI annex. In summary, we proposed for the independent user group to set ambitious targets for stakeholder engagement for us, against which the group would hold us to account.

We asked if Ofgem had assessed our stakeholder engagement ODI in emails to Ofgem on 14 July 2020 and 21 July 2020. Ofgem responded orally to us that our approach to stakeholder engagement reputational incentives sounded acceptable.

Our proposed approach to customer engagement reputational incentives is consistent with the view Ofgem set out in paragraphs 4.36 to 4.41 of the core document. We therefore conclude on the basis of Ofgem's oral confirmation that our approach to stakeholder engagement reputational incentives is acceptable to Ofgem and consistent with its DD.

ETQ1 Do you agree with our proposals to switch off the incentive in year one of RIIO-ET2 in order to pilot the Quality of Connections survey and develop the baseline targets?

The response to this question covers other issues about the quality of connections (QoC) survey incentive that Ofgem discusses in the DD but are not covered in Ofgem's two questions on it.

<u>Proposal to switch off the QoC survey incentive in year 1 of the RIIO-2 period</u>
We strongly support applying the financial incentive to the QoC survey incentive for year 1 of the RIIO-2 period (and therefore oppose switching it off), for the following reasons:

- It would be much better for our customers and consumers if there was an incentive in year 1. The obvious effect of switching off the QoC survey incentive in year 1 is to encourage TOs to focus their limited resources on other commitments in their business plans rather than on improvements to customer service.
- Ofgem has accepted there is a need for an incentive in year 1 for the equivalent incentives for gas distribution and gas transmission. For gas transmission Ofgem is applying similar changes to the survey as for electricity transmission. Ofgem is setting the T2 target for gas transmission based on performance as at 2018/19, because this passes sense checks such as being higher than the T1 average score and being on a par with the latest rolling three-year average of the T1 period.
- Ofgem's DD is proposing large reductions to our other customer-related ODIs such as rejecting our bespoke ODIs on outage management and accelerating low-carbon connections and also reducing the size of the QoC survey incentive (see below).

<u>A proposal for the QoC survey incentive in year 1</u>
We propose the following way of applying the incentive in year 1:

- The incentive will be switched on from 1 April 2021.
- The baseline for year 1 of the RIIO-2 period is set at 7.4. This is the same as the RIIO-1 target of 7.4 for SPT and SHE-T, which is 0.5 points above NGET's RIIO-1 CSAT target of 6.9 (and equal to our RIIO-1 SSAT target for T1 of 7.4).
- Our independent survey company will carry out surveys at the proposed milestone, as described on the joint methodology and Ofgem's DD, from 1 April 2021.
- The incentive penalty or reward will be determined against the baseline of 7.4 for NGET.
- Given that it is the first year of the updated survey the baseline would be adjusted according to the following table to preserve the incentive for NGET to improve our performance, while ensuring consumers are protected from our performance being unexpectedly high in the first year.

Table for adjusting the Year 1 baseline for outturn Year 1 performance

Baseline at the beginning of Year 1	**Average outturn for the three TOs in Year 1**	**Adjusted baseline for year 1**	**Reason**
7.4	6.5	7.1	The baseline for year 1 decreases in steps as the outturn performance reduces. The baseline does not decrease as much as performance to preserve the incentive for NGET to stop performance slipping.
7.4	6.6	7.1	
7.4	6.7	7.2	
7.4	6.8	7.2	
7.4	6.9	7.3	
7.4	7.0	7.3	
7.4	7.1	7.4	No change to the baseline for year 1 because outturn performance is not very far from the original year 1 baseline of 7.4.
7.4	7.2	7.4	
7.4	7.3	7.4	
7.4	7.4	7.4	
7.4	7.5	7.4	
7.4	7.6	7.4	
7.4	7.7	7.4	
7.4	7.8	7.5	The baseline for year 1 increases in steps as the outturn performance increases. The baseline does not increase as much as performance to preserve the incentive for the NGET to improve.
7.4	7.9	7.5	
7.4	8.0	7.6	
7.4	8.1	7.6	
7.4	8.2	7.7	
7.4	8.3	7.7	
7.4	8.4	7.8	
7.4	8.5	7.8	

- Another advantage of this approach is that Ofgem will have a full year of data for the T2 survey, rather just the period of the pilot, to inform the setting of the baseline for Years 2 to 5.

An insufficient and uncertain incentive size and strength

Ofgem is creating unnecessary uncertainty for TOs about the financial package for RIIO-2 by not setting out in advance the size of the QoC incentive range and the strength of the incentive rate. These should be integral parts of the draft determinations. Ofgem has provided this information for the gas distribution and gas transmission companies.

Ofgem should carry out a mini-consultation on a proposed incentive size and strength for the QoC survey incentive to enable it to set these in its FD.

The incentive size for the QoC survey should be larger than the 0.4% of revenue assumption in Ofgem's DD.

In the SSMD Ofgem said:

> "We have considered the responses that suggest we should retain the strong symmetrical incentive arrangement from RIIO-ET1, which is +/-1% of the Base Revenue. However, due to our decision to set apart the connections stakeholders in the survey sample for RIIO-ET, it may be appropriate to reduce the incentive strength for RIIO-ET2." (paragraph 2.105)

In the DD Ofgem has moved way from restricting the QoC survey incentive to connection stakeholders and is consulting on the survey covering all generation or demand customers who are: researching into/intending to connect to the transmission system; researching into/intending to connect to the distributions system in a way that required transmission works (embedded generators); and connected to the transmission system or a distribution system and impacted by transmission activities. Therefore, the original motivation for reducing the strength of the QoC survey incentive no longer applies.

In addition, Ofgem's DD proposes rejecting our customer-focused bespoke ODIs on outage management and accelerating low-carbon connections. Reducing the incentive size of the QoC survey incentive to 0.4% of base revenue as well will lead to large drop in the size of incentives aimed at improving service for customers at a time when we have seen a large jump in the number of smaller and new customers, such as solar farms and battery providers, wanting to connect to our network who will particularly benefit from a strong incentive on us to improve and adapt our customer service to them.

If Ofgem will not increase the size of the QoC survey incentive in FD it should consider reducing the range over which the incentive applies to increase the strength of the incentive per unit of out- or under-performance. Ofgem is proposing this approach for gas transmission.

A lack of clarity over the target

Ofgem must consult in advance how it will set the target for the QoC survey incentive to give TOs and stakeholders some view of what the target might be for planning purposes.

ETQ2 Do you have views on the common milestones, target audience and question of overall satisfaction for the Quality of Connections survey incentive provided in Appendix 2?

We support the common milestones, target audience and the question of satisfaction with the TO based on the customer's experience of the milestone/moment that matters set out in appendix 2. This was a joint proposal between us, SPT and SHE-T.

Our joint proposal on common milestones reflects our engagement with our customers on what are the main moments that matter for them and therefore what are the most appropriate points for them to be surveyed at.

Our joint proposal on the target audience captures the main customers who are connecting to or directly affected by our network.

Our joint proposal on the question of satisfaction of experience reflects best practice.

If, following its consultation on the DD, Ofgem decides to exclude customers affected by outages or the outage management milestone from its final determination on its QoC survey common ODI we strongly request that Ofgem reinstates our quality of outage management bespoke ODI because it reflects the importance of outage management for our customers. As we explained in our RIIO-2 business plan ODI annex our customers have told us through our stakeholder engagement that we can still improve the way we communicate and manage outages and a symmetric incentive is a proportionate way of encouraging these improvements.

ETQ3 Do you think there are any additional KPIs that have not been included in the final NAP which would support monitoring of performance in adherence to the NAP and/or add transparency of the outage planning, management and implementation process for relevant stakeholders?

We believe that the proposed KPI's in the final NAP are fairly comprehensive and have been well consulted on with a wide range of stakeholders, therefore there is no need for any further KPIs.

ETQ4 Do you agree with our proposed LPD mechanisms and do you agree with the criterion that we are proposing to use for our LPD mechanisms?

Our response to this question contains a summary and then comments on the three areas of Ofgem's DD proposals for LPD in more detail:

1. the reprofiling of allowances;
2. a milestone-based approach to recovery of allowances; and
3. a project delay charge

Our response to this question repeats many of the points we made to Ofgem in our email of 23 March 2020, except where Ofgem's DD has taken a different approach to that in its email of 18 March 2020 to TOs.

Summary

We recognise that in the DD proposals for LPD Ofgem is trying to achieve the best approach for consumers. The fundamental issue in the LPD work is the need to balance the benefits to consumers from projects not being delayed with the benefits to consumers of keeping delivery costs down. We consider the best approach involves risk-sharing between TOs and consumers.

We welcome that Ofgem has adjusted its approach to LPD since the SSMD in March 2019 to take account of feedback from stakeholders. We think further adjustments and clarifications are needed for LPD to provide the best outcome for consumers as we explain below.

We have the following comments on the three elements of LPD:

- We agree with **re-profiling of allowances**, for delayed projects only, to remove the time value of money for delays only, after the delay has happened. We agree with Ofgem's proposal that this should be the default approach to LPD. TOs should be given an opportunity to explain if a delay was actually in the best interests of consumers before Ofgem applies the re-profiling. Re-profiling should not apply to projects that are not delayed. Re-profiling should not remove efficiency savings TOs make when delivering a project.
- Ofgem should drop the **milestone-based approach to recovery of allowances**. The milestone-based approach results in TOs being cash negative during projects' lives and will increase financing costs. Reprofiling can achieve what Ofgem wants to achieve from the milestone-based approach.
- The **project delay charge** should involve us passing on any liquidated damages we receive from our contractors for delays to our customers (who should then pass these on to end consumers). We are also incentivised to avoid delays by the additional costs that usually result from them. If Ofgem decides to apply additional penalties on TOs for delay, making such penalties too high will be detrimental for consumers in a number of ways including: discouraging innovation; causing contractors to increase their prices; encouraging TOs to adopt conservative project delivery timescales; increasing the cost of capital; and encouraging TOs to spend inefficiently to achieve project deadlines.

We are also concerned that Ofgem has not explained **how LPD relates to the approach to PCDs**. Ofgem's approach to PCDs in the DD allows for it to carry out an ex post review, where a company has not delivered precisely the approach set out in its PCD, of whether the network company had carried out the work innovatively and efficiently. Ofgem's approach allows it to clawback allowances where it disagrees with the approach the network company has taken. This approach to PCDs overlaps with LPD and Ofgem should remove this overlap in its FD. We set out our concerns about the PCD framework in more detail in response to question NGETQ5 below.

In the next sections we comment on the three areas of Ofgem's DD proposals, starting with the reprofiling of allowances.

1. Reprofiling of allowances

Ofgem's DD proposal for reprofiling of allowances
"…we propose that all projects that match our proposed LPD criterion are included as forecast costs when we set the allowances for those projects. These would then have allowances

updated annually to match actual spend, unless we opt to pursue a milestone-based approach to recovery of allowances on that project." (paragraph 2.65, DD ET annex)

We agree that TOs should not benefit financially from delays in delivery. For delayed projects, which tend to have cost overruns, we agree that an ex-post, re-profiling of allowances to remove the time value of money benefit of the delay would be appropriate.

We are very concerned by Ofgem's statement that Ofgem would "have allowances updated annually to match actual spend". Reprofiling should not remove efficiency savings TOs make when delivering a project. If there is a risk Ofgem will remove efficiency savings by updating allowances to match actual expenditure it will remove the incentive under the TIM for TOs to achieve cost savings for consumers because Ofgem will claw them all back. Even if Ofgem only intends to reprofile delayed expenditure we are not clear how Ofgem will distinguish between delayed expenditure and lower expenditure due to efficiency when reprofiling our expenditure, which could also undermine the TIM.

Ofgem's two paragraphs on re-profiling in the DD do not explain when reprofiling would apply. Ofgem should clarify that reprofiling should not apply to projects that are not delayed.
A true up of all our projects and/or a true up which removes efficiency gains as well as the time value of money, could create significant financeability issues for us, particularly if the revenue adjustment was to be made in a single year when our financial position will already be constrained.

Before Ofgem applies any reprofiling TOs should be given an opportunity to explain if a delay was in the best interests of consumers. There can be reasons why a project delay might be the right thing for consumers and where re-profiling allowances would not be appropriate. For example, when unforeseen delivery issues occur a delay to the project might reduce the cost overrun compared to trying to continue to deliver the project on time. In this case the delay can reduce costs to consumers because their share of the cost overruns, through the TIM (which are 60.8% of cost overruns for NGET's consumers in the DD proposal), is lower.

2. Milestone-based approach to recovery of allowances

Ofgem's DD proposal for the milestone-based approach to recovery of allowances
"…TOs would be required to forecast milestone delivery dates ahead of Ofgem taking a funding decision for the project. The allowances contingent on those milestones would be included as forecasts in the PCFM, such that the allowance is delayed in the event that a milestone was not delivered on time." (paragraph 2.69, DD ET annex)

Ofgem should drop the milestone-based approach. The milestone-based approach results in TOs being cash negative during projects' lives and will increase financing costs.

We have financeability concerns about the milestone-based approach. If we do not receive payment for the work we carry out until we complete the milestone we will be cash negative during project delivery when there is already limited capacity under Ofgem's DD financial package to absorb additional costs without funding. This effect is worsened by the regulatory system involving a two-year lag for receiving revenue. This would mean that we would not receive funding for any milestones we delivered in Year 4 or Year 5 of the RIIO-2 period until the following regulatory period.

In the example below, if we delivered all 3 milestones on time, we would have incurred 100% of the cost in the RIIO-2 period, but only been allowed 33.3% of the funding in the RIIO-2 period. This would have a significant impact on our financeability.

Expenditure and revenue profile for a milestone-based approach project

	RIIO-2					**RIIO-3**	
	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28
Milestone delivered (33.3% each)		1		2	3		
Allowances received (cumulative)				33.3%		66.6%	100%

We propose a better approach in terms of financeability, while protecting consumers, would be for our allowances to be based on our forecast output delivery. If the project is off-schedule we would include this in our forecast and our allowances would be re-profiled to when we forecast we would deliver the output. This approach would provide greater funding certainty while still encouraging us to avoid project delay.

While, we disagree we the milestones-based approach, we welcome that Ofgem has listened to stakeholder feedback and if it takes forward the approach proposes to define the milestones close to the start of the project when they will be clearer, rather than at the beginning of the price control period. The milestones will have to be specific to each project because TOs' projects vary so much in size, scope and type. Also, we have contracts for different aspects of large projects such as substations, cables, overhead lines and civils. Each of these work packages can have different contract structures with different milestones that can be spread across many years. When we aggregate these contracts into high-level milestones this could shift more risk onto TOs which we would need to take account of.

If Ofgem adopts a milestones-based approach it should put those milestones into our licence so that we have a right of appeal should we strongly disagree with them.

If Ofgem adopts a milestones-based approach for a project there will need to be a change control process for milestones to allow for external events, such as a generator customer delaying its project. It would not benefit consumers to hold us to milestones and incur costs earlier than needed when, for example, the generator would not be ready to connect. This change control process would have an associated administrative burden.

Ofgem recognises in paragraph 2.69 that: "[The milestones-based approach] would work in a similar way to the re-profiling mechanism". Ofgem can achieve its objectives with re-profiling and avoid the financing issues created by the milestones-based approach. Ofgem should therefore drop the milestones-based approach.

Project delay charge

Ofgem's DD proposal for the project delay charge

- "We would set a pre-agreed ex-ante day-rate charge, payable by the TOs to consumers, for each day that a project is delivered late.
- Consistent with industry standard approach to liquidated damages, the total amount payable by the TO would be capped at a fixed, pre-agreed, level.
- Using industry benchmarks, at Final Determinations we propose to provide an indicative view of what the charge could be and what level the cap could be set at, and then confirm this on a project-by-project basis through project specific consultations." (paragraph 2.71, DD ET annex)

The project delay charge should involve us passing on any liquidated damages we receive from our contractors to our customers (who should then pass these on to end consumers). We are also incentivised to avoid delays by the additional costs that usually result from them.

It is beneficial for consumers that Ofgem is no longer proposing to link the mechanism to "actual" constraint costs. As we explained in our response to the sector-specific methodology consultation, in March 2019, linking any penalties to actual constraint costs could be detrimental to consumers because actual constraint costs are unpredictable, uncontrollable and potentially very large. This would be detrimental for consumers as we describe in the numbered points below.

The DD provides some guidance, but only some, about how the project delay charge will be set:
- a pre-agreed ex-ante day-rate charge; and
- consistent with industry standard approach to liquidated damages the total amount payable by the TO would be capped at a fixed, pre-agreed, level.

Ofgem says it will provide an indicative view of what the charge and cap could be at FD and will then confirm this on a project-by-project basis through project specific consultations. Ofgem should provide this indicative view to stakeholders in a mini-consultation before reaching a view in its FD.

The uncertainty about what the project delay charge might makes it difficult for us to agree contract details with our suppliers because we all need to know what the consequences of a delay will be financially and take steps to adapt to this accordingly.

If Ofgem decides to apply project delay charges to TOs, Ofgem will need to take account of the possible perverse effects, which could be detrimental to consumers, of penalties for TOs which are too high. Requiring TOs to pay too high a level of consumer detriment penalties could:
1. discourage TOs from taking innovative approaches that are lower cost or deliver better service quality because they are new and subject to a greater risk of delay;
2. result in contractors increasing their prices to reflect TOs seeking liquidated damages in the event of delays;
3. encourage TOs to reduce risk and keep down insurance costs by using conservative delivery timescales;

4. increase the cost of capital as the sector is perceived by investors to have become riskier; and
5. encourage TOs to spend inefficiently to achieve a deadline with consumers picking up a share of these costs through the TIM sharing factor (especially if the TIM sharing factor for consumers is higher in the T2 period).

We explain our proposal for mitigating the impact of late delivery on page 56 of the NGET 200-page RIIO-2 business plan and pages 29-30 of our Annex NGET_ET.08_Outputs. Our proposal is that any contractual payments for damages we receive from suppliers should be the amount used to offset any consumer detriment from any delay or non-delivery. We propose that we would return these payments to our customers through lowering TNUoS by the amount of the consumer detriment payment. Our customers could then pass this reduction onto consumers. We are also incentivised to avoid delays by the additional costs that usually result from them.

Ofgem should also allow for there sometimes being benefits to consumers from delay and waiving any penalty for consumer detriment. A TO could present evidence about why a consumer detriment penalty for delay was not appropriate because it was in consumers' best interests to delay. A TO would have to show that the delay led to lower costs being passed onto consumers and/or that it allowed TOs to improve the service quality during delivery (e.g. an increase the amount of community engagement above original plans).

Ofgem's approach project delay charges, and the uncertainty over their level, also has financeability implications. Ofgem's current proposal for the cost of equity in the T2 period is too low to allow for us taking on large risks for project delivery in the T2 period. Therefore, the proposal Ofgem eventually makes for project delay charges needs to take account of the possible perverse effects of setting penalties for TOs too high, which include increasing the cost of capital.

ETQ5 What are your views on applying our LPD mechanisms to some or all of the projects identified at paragraph 2.73?

[*Note: we think this question refers to the list in paragraph 2.74 of the currently published version of the Ofgem DD for the ET sector, following Ofgem republishing it on 17 July 2020*.]

We have set out our concerns about LPD in our response to question ETQ4 above.

Ofgem mentions two projects for NGET in paragraph 2.74:
- London Power Tunnels (NGET); and
- Bramford-Twinstead (NGET)

London Power Tunnels (LPT) should not be covered by the LPD mechanisms because it is a non-load project. We do not think LPD should apply to non-load projects for the following reasons:

1. Non-load projects are covered by NARM and measured by monetised risk.
2. Non-load projects have targets that are a risk level not a delivery date.
3. Under NARM TOs should be able to flex their plans when delivering the agreed risk target.
4. The delivery of asset replacement is much more closely linked to gaining access to the existing network and TOs need the ability to flex this to avoid operational constraints.

5. The ESO needs to have a role in deciding the best delivery timing and this will change as the project progresses, for example, it is often more economical to delay a project than run with an expensive outage. Factors such as generation plans and weather can affect the best delivery timing.
6. TOs need to optimise system access and resources across a portfolio, not individual projects to deliver at an efficient cost for consumers.

ETQ6. What are your views on our consultation position for the three electricity TOs' EAP proposals in RIIO-2 as set out in this document?

We welcome that Ofgem are proposing to accept all of our environmental targets. We believe our proposals will have a significant bearing in the reduction of our environmental impact during the course of 2021-2026. We also welcome the proposal to report progress against our targets using an AER. We have already been reporting our environmental progress, via an annual report during the course of RIIO-T1. We have feedback on the mechanics and reporting details of the business plan data tables which may evolve in to the reporting templates, which we will feedback on during the workshop scheduled for 9th September.

We welcome the acceptance of the proposals for EVs, however clarification is sought over the model used for price parity as we understand the model used relates to car price parity and not commercial vehicles. We also have significant concerns over the reduced allowance for the remaining diesel fleet, which could significantly impact our ability to support our operational fleet. This is discussed in questions NGETQ6.

ETQ7. What are your views on our consultation position for setting the expenditure cap for visual amenity mitigation projects in RIIO-2?

We are satisfied with the proposed expenditure cap of £465m for visual amenity mitigation projects. This is aligned with the priority list of undergrounding projects that have been shaped by our external Stakeholder Advisory Group. Setting a higher funding cap for Landscape Enhancement Initiative (LEI) projects will also be welcomed by our stakeholders. We hope this will encourage applicants to come forward with more innovative projects. Ofgem's new streamlined process will also make it easier to approve these projects, which is a positive step.

We note that the Draft Determination did not include the relevant proportion of costs for NGET's approved RIIO-T1 visual amenity project (Dorset VIP); Ofgem have already approved T2 expenditure of £12.7m (2017/18 prices) in RIIO-T2 period. Similarly, on the approved LEI projects, approximately £0.07m will be incurred in the RIIO-T2 period. We ask Ofgem to clarify how this (and further funding for projects which are still to be considered by Ofgem in the RIIO-T1 period) will be enabled through the T2 Licence and how it is intended to adjust baseline allowances to allow us to recover the cost.

ETQ8. Do you have any views on our outputs that have not been covered through any of the specific consultation questions set out elsewhere in this chapter? If so, please set them out, making clear which output you are referring to.

We provide our response on Ofgem's general policy on outputs or price control deliverables (PCDs) in our answer to NGETQ5 on PCDs.

We provide our views on the following NGET outputs that Ofgem has not covered in its specific consultation questions:

- Energy not supplied common ODI-F: please see the start of our response to the DD ET annex above before question ETQ1.
- IIGs leakage common ODI-F: please see the start of our response to the DD ET annex above before question ETQ1.
- Stakeholder survey for New Transmission infrastructure projects: please see the start of our response to the DD ET annex above before question ETQ1.
- Timely connections common ODI-F: please see the start of our response to the DD ET annex above before question ETQ1.
- Stakeholder engagement bespoke ODI-R: please see the start of our response to the DD ET annex above before question ETQ1.
- Outage management bespoke ODI-F: please see our response to the DD NGET annex between questions ETQ10 and ETQ11.

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

We have numerous concerns with the overall approach to setting totex allowances. The following aspects of Ofgem's Draft Determination approach are currently unacceptable:

- Extensive reductions in volume of allowed investment for Network Reliability and Resilience which jeopardises a safe, reliable and resilient network service
- Extensive reductions in allowances due to assessment of costs as inefficient, which are actually the result of errors, methodology weaknesses, data handling issues and inconsistent comparisons
- Ex-post re-opening and clawback of settled T1 allowances where no mechanism or vires exists, undermining the 'stable and predictable' RIIO regulatory regime
- Ex-post funding approach for additional network capacity that adds unnecessary risk and delay to delivery of investments that are critical to delivering net zero
- Overstretching and unjustified Proposals for Ongoing Efficiency

We provide detailed explanation of the above points in our responses to relevant questions in the core and NGET-specific response documents. Our concerns regarding Ofgem's approach to assessing the efficiency of our costs are set out below.

Load and non-load related network capex

Due to the commercially confidential nature of our capital cost information, we have summarised our concerns in this public response to the Draft Determinations consultation. We have included a review of Ofgem's methodology and processes in this, our response to ETQ9. We have then provided specific responses on the consequences of the cost assessment process on our load-related and non-load related capex in responses to NGETQ11 and NGETQ12 respectively. We are also providing a confidential appendix for Ofgem that provides fuller explanation and analysis of our concerns around the cost assessment process.

Ofgem stated that network capex assessment will be undertaken through three primary workstreams:

i. Needs case assessment - focusing on the rationale for the proposed scheme considering the options to meet the functional requirements and the timing of the work.
ii. Network Asset Risk Metric (NARM) - reviewing how transmission companies have planned for offsetting the natural degradation of the network assets over time.
iii. Cost assessment - reviewing the appropriateness of the costs for the work that passes both the need case and NARM assessments.

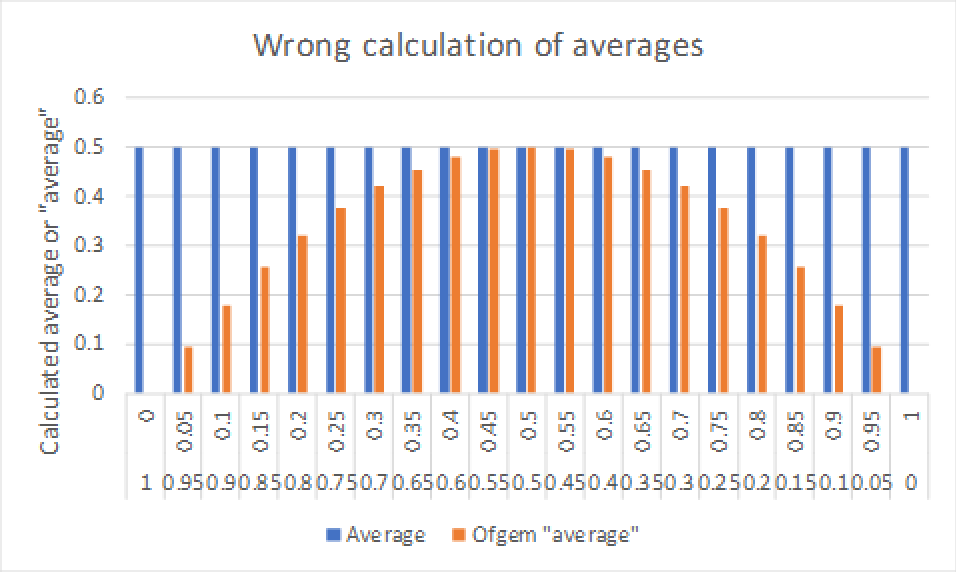
Our views on the first two workstreams are addressed in our responses to NGETQ11 and NGETQ12. The following sections discuss the third workstream.

<u>Network capex cost assessment</u>

Ofgem's approach to assessing the efficiency of network capex is not fit for purpose.

- **It is inconsistent with the approach proposed so far in the consultation process.** In spite of Ofgem's Sector-Specific Methodology Decision document recognising key differences between Transmission and Distribution networks, Ofgem's approach for T2 has fundamentally shifted to try and treat Transmission projects in a similar way to a Distribution cost assessment. This means that valid cost drivers for transmission projects have not been adequately reflected in the setting of draft allowances.
- **In the Draft Determinations, Ofgem has been inconsistent between companies.** Ofgem's approach to cost assessment for NGET'S NLRE is not consistent with that applied to other TOs. Largely as a result of the non-standard approach adopted, a cost reduction of 19% has been determined across the NLR portfolio (as opposed to 11% for the LR portfolio that passed through Ofgem's Project Assessment Model); this peaks at a 76% reduction for Protection & Control unit costs.
- **The methodology is conceptually flawed.** The systematic approach of reducing above-mean company costs to Ofgem's view of an efficient sector mean while passing through unadjusted below-mean costs means that even a company whose costs are on average lower than Ofgem's efficient sector mean will have their submission reduced if they have any spread in costs around the mean. The net result is that every company will have mean allowed unit costs that are lower than Ofgem's efficient sector mean. This approach does not recognise the natural spread of costs that would exist in any portfolio of work and perversely rewards companies whose costs are consistently higher than the sector mean.
- **The methodology Is not transparent and the process around consultation on it flawed.** Ofgem's T2 cost assessment workshops did not involve the sharing of their cost model; had this been done, a number of basic errors and inconsistencies could have been addressed prior to submission. Ofgem's published DD contained numerous numerical errors. They were slow to provide the supporting analysis that allowed us to understand their proposals and show how they reached their conclusions on cost assessment (with one supporting spreadsheet not being provided until 21 August 2020, six weeks into the eight-week consultation period) and have not been able to provide the contemporaneous calculations for the significant reductions in NLR allowances. The supporting spreadsheets that have been provided are complex and inconsistent. This has adversely impacted our ability to respond in the consultation period, meaning it is likely that the issues identified in this document are not a complete list and that more will be surfaced between now and Final Determinations.
- **Uses a methodology that contains material errors.** An example of this is the averaging of cost ratios used to determine Ofgem's deduction factors against NGET's NLR direct asset costs, where the required ratios were inverted, averaged and then the result inverted again. This will only correctly calculate the average of two identical numbers; for all other cases, the answer will be lower than the true average. The graph

illustrates this for number pairs that average to 0.5 (from 1,0 to 0.5,0.5 to 0,1 as shown by the horizontal and vertical numbers on the x axis)



The net result is unjustified cost reductions of 11% on load-related capex and (due to the errors introduced by the inconsistent cost assessment) 19% on non-load related capex. This is before Ofgem's application of an extremely stretching ongoing capex efficiency of 1.2% per annum, which equates to an average of 6% on top of the above. Given the fact that we have incorporated all our efficiencies and innovations from T1, taking another 25% out of non-load related costs is unfeasible and leaves NGET with interventions in certain asset categories that cannot be delivered for the stated DD Final Allowances.

Ofgem have acknowledged that there are shortcomings associated with their non-standard assessment approach and expressed a strong preference to put our non-load related data through the Project Assessment Model (PAM) for Final Determinations. Now that we have full visibility of Ofgem's spreadsheets, we are working with Ofgem to recut our non-load related data so that they can flow it correctly through the PAM. This will automatically correct some of the errors and we therefore expect the cost assessment reductions applied to NLR capex to decrease significantly between Draft and Final Determinations.

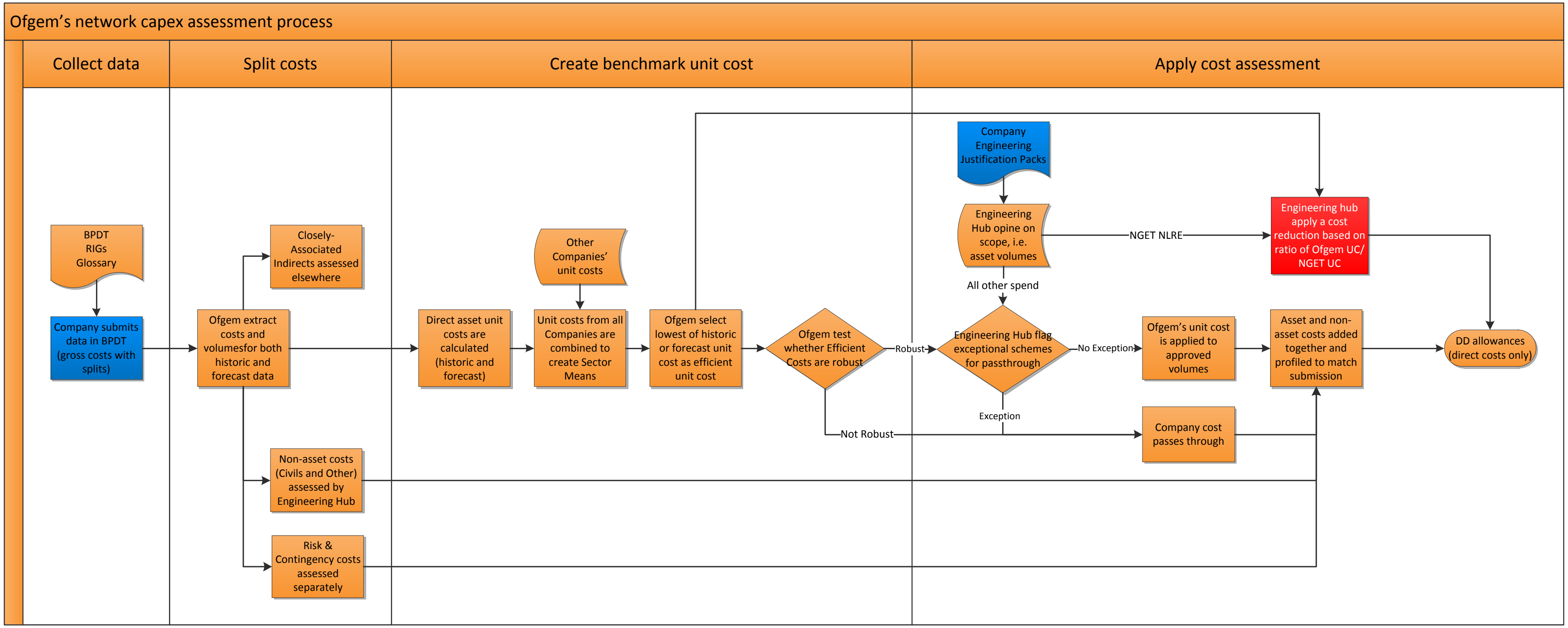
<u>Proposed improvements to Ofgem's network capex cost assessment process</u>

- Ofgem should use a process better suited for transmission projects which are bespoke and involve non-repeatable workloads. This especially applies to cable projects, substation builds/rebuilds and anything other than routine like-for-like replacements.
- Where Ofgem are able to benchmark costs on lower-value, higher-volume projects, they should benchmark gross costs to avoid issues associated with different cost splits such as choice of delivery vehicle.
- Ofgem should refine their asset categories to better-reflect valid cost drivers, such as power rating.
- Ofgem must put NGET's NLRE through the PAM wherever possible so that allowances are calculated consistently with other companies.
- Ofgem should correct the PAM to correctly scale company's mean unit costs to the sector mean, rather than reducing costs where they are above their view of an efficient mean and passing through those that are below.
- Where the PAM is inadequate (e.g. for Protection schemes), Ofgem should undertake a reasonable and transparent assessment of costs outside the model for all companies and add them back in to Final Allowances.

- Ofgem should not use their approach of reducing costs where they are above their view of an efficient mean for allowing baseline costs or Risk & Contingency.

Overall process

Ofgem have significantly changed the way that they assess the cost of capital projects for the T2 period as compared to previous price controls. The following diagram sets out our understanding (as we have been able to infer it from their verbal explanations and spreadsheets) of Ofgem's two approaches to capital cost assessment for Draft Determinations.


Ofgem's network capex assessment process
Collect data
Split costs
Create benchmark unit cost
Apply cost assessment
BPDT RIGs Glossary
Company submits data in BPDT (gross costs with splits)
Closely-Associated Indirects assessed elsewhere
Ofgem extract costs and volumesfor both historic and forecast data
Non-asset costs (Civils and Other) assessed by Engineering Hub
Risk & Contingency costs assessed separately
Direct asset unit costs are calculated (historic and forecast)
Other Companies' unit costs
Unit costs from all Companies are combined to create Sector Means
Ofgem select lowest of historic or forecast unit cost as efficient unit cost
Ofgem test whether Efficient Costs are robust
Robust
Not Robust
Company Engineering Justification Packs
Engineering Hub opine on scope, i.e. asset volumes
NGET NLRE
All other spend
Engineering hub apply a cost reduction based on ratio of Ofgem UC/ NGET UC
Engineering Hub flag exceptional schemes for passthrough
No Exception
Exception
Ofgem's unit cost is applied to approved volumes
Company cost passes through
Asset and non-asset costs added together and profiled to match submission
DD allowances (direct costs only)

The following sections will first highlight our concerns over the end-to-end process and then step through the issues encountered at each stage of the above process.

Ofgem approach, as consulted upon

In the Sector-Specific Methodology Decision document published by Ofgem on 24th May 2019, Ofgem confirmed that their approach would be to use a range of techniques underpinned by use of historical cost data, as appropriate, in determining their view of efficient costs. They stated that, while they expected a significant proportion of the business plan submission would lend itself to a detailed project-specific cost assessment approach, there would also be volumes of less material work that cannot be scrutinised in the same level of detail. They expected to conduct a high-level assessment of such work within each submission, combined with the sampling of specific projects, to come to a view on the suitability of proposed cost levels.

A further consultation document, 'RIIO-2 tools for cost assessment', was published in June 2019. This document reiterated the approach outlined in the sector-specific consultation, namely:

- Comparison with relevant historical costs for similar work
- Comparison of costs for individual projects on a unit cost basis – disaggregating project costs into their individual elements to facilitate cost comparisons between projects on a cost per unit basis, as appropriate
- Evidence from market testing of costs
- Maturity and firmness of cost estimates
- Benchmarking of costs where appropriate: certain elements of costs will be benchmarked against comparators; where similar types and levels of activity are evident
- Expert review: some elements/activities within companies' business plans may require experts to assist Ofgem analysis and will inform the Ofgem position

The broad principles outlined above are reasonable, although there was no detail provided to clarify the circumstances covered by "as appropriate". The quality of any benchmarking exercise is entirely dependent on being able to obtain a statistically-significant sample of "similar work".

NGET approach

Amongst the information NGET provided as part of the business plan submissions, the following are key for the cost assessment process:

- Completed **Business Plan Data Template (BPDT)** – these are the spreadsheets that contain the numbers required by Ofgem to determine allowances for the price control period. The format was not issued for consultation but was developed in conjunction with the TOs. This development continued until 20th September 2019 when a final document and associated guidance notes were issued. The templates are more complex than those used in the RIIO-T1 price control review and subsequent Regulatory Reporting; they capture significantly greater amounts of data 420,000 cells compared to 160,000 cells in the RIIO-T1 RRP pack. During development workshops and in correspondence, the TOs pointed out deficiencies in the table structure such as mixing of Opex and Capex costs together in a single table with no transparency (namely Network Operating Costs and Closely Associated Indirect) which would likely lead to confusion and an inability to see long-term trends.
- **Business Plan Data Template Narrative** – this is a document that provides explanatory notes for the Business Plan Data Templates. Ofgem set out a number of questions that were required to be answered. In this document, the TOs identify any pertinent information that helps understand some of the trends observed in the data tables such as cost drivers and validation against historic costs.

- **Investment Decision Packs** - these combine the Engineering Justification Papers (EJPs) and Cost-Benefit Analyses (CBAs) at a scheme or portfolio level. EJPs and CBAs were cross-referenced in the BPDT for ease of navigation. The purpose of the EJP is to provide further insight into the need for the intervention, the options considered for resolving the need and any further information relevant to the investment. Ofgem provided the template for CBAs (a spreadsheet) which was completed to show the options assessed for each intervention.
- **Network Asset Risk Metric** tables – these tables showed the impact on network risk of the proposed investments. The asset tables are cross-referenced to the BPDT to allow the cost and outcome to be viewed together.
- **Supplementary Questions** – specific questions raised by Ofgem to clarify understanding of data provided in the submission to support the engineering need and cost assessment.

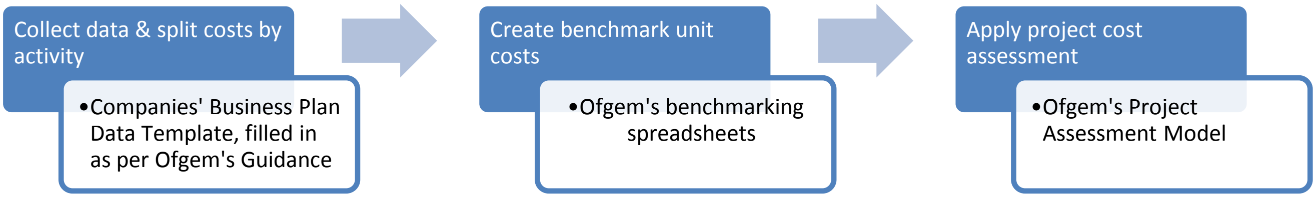
Our BPDT cost estimates were built using inputs including outturned costs experienced in T1. These costs were then reviewed to ensure that all efficiencies achieved in T1 had been built into T2 estimates, such as the move to targeted interventions for certain P&C asset types and OHL fittings. We also reflected the differing mix of cost drivers within the portfolio, such as the in situ/off-line transformer replacement mix. Finally, National Grid engaged with an independent consultancy with experience and knowledge of transmission project costs (TNEI) to provide an industry benchmark of unit costs. Where National Grid's proposed unit costs were above TNEI's industry benchmark, an efficiency was applied to the submitted plan. Finally, an ambitious ongoing efficiency assumption for NGET's staff costs was overlaid.

Ofgem approach to Draft Determinations

Ofgem's consulted-upon approach	Actual approach	Issues
Comparison with relevant historical costs for similar work	Ofgem have used companies' BPDTs to calculate unit costs for historic and forecast schemes and then selected the lowest as a benchmark The dataset is a combination of LR and NLR expenditure.	No evidence of normalisation for "similar work" or use of data cleansing function to remove outliers. It is not clear what the criteria were for concluding that a benchmark was robust enough to use. The output of cost assessment does not reflect the differences in scope and cost between LR and NLR schemes.
Comparison of costs for individual projects on a unit cost basis – disaggregating project costs into their individual elements to facilitate cost comparisons between projects on a cost per unit basis, as appropriate	Ofgem have used their PAM to build their view of an efficient project cost for NGET's LR plan based on their benchmarks for direct asset costs NGET's NLR plan was assessed in a non-standard way	Inconsistency of approach and outcome between NGET's LR and NLR, and between NGET and other companies.
Evidence from market testing of costs	No evidence of Ofgem taking account of market-tested costs	
Maturity and firmness of cost estimates	Ofgem have allowed the costs for projects that are in delivery, i.e. have awarded contracts	Disallowance of robust cost estimates for lower-value, repeatable work based on the use of historic averages.
Benchmarking of costs where appropriate: certain elements of costs will be benchmarked against comparators; where	Ofgem have used companies' BPDTs to calculate unit costs for historic and forecast schemes	No evidence of normalisation for "similar work" or use of data cleansing function to remove outliers. The use of a weighted

similar types and levels of activity are evident	and then selected the weighted mean as a benchmark	mean assumes a normal distribution of costs; this is unlikely to be valid.
Expert review: some elements/activities within companies' business plans may require experts to assist Ofgem analysis and will inform the Ofgem position	It is not clear from the evidence provided whether this has happened.	Lack of transparency regarding this aspect of the process.

We have observed a number of issues with Ofgem's cost assessment approaches. To understand the interactions, it is helpful to consider a three-box process:



Stage 1. Collect Data & Split Costs by Activity

This is the area where some of the biggest changes (compared to cost assessment for previous transmission price control reviews and 15 years of annual Regulatory Reporting) have occurred.

The format of the Business Plan Data Template is materially different and was still being adjusted up until 20th September 2019, with seven iterations being provided by Ofgem between the draft submission in July 2019 and that date. The BPDT was accompanied by new RIGs and a Glossary which were a significant shift from those established for Transmission companies through annual Regulatory Reporting. There are ambiguities and contradictions in definitions which mean that companies have, despite best intentions, undoubtedly submitted data in different ways. This means that materially different units have been benchmarked as though they were the same. These inconsistencies and their impact are described in further detail in our responses to NGETQ11 and NGETQ12.

In spite of companies being required to make draft submissions in July and October 2019 so that Ofgem could check their models, Ofgem did not flag specific problems with data consistency between companies nor that NGET's approach to populating tables would prevent them being able to properly undertake their cost assessment process prior to the final submission of the BPDT in December 2019. Furthermore, Ofgem did not share their cost assessment models so that companies could help improve them and make suggestions to improve the consistency of submitted data. This step would have greatly improved the quality of Draft Determinations.

By requiring companies to split gross capex costs between Direct Lead Asset, Non-Lead Asset, Civils and Other Costs, and Indirect costs (the latter being wrongly classified and assessed as operating expenditure) and treating them separately, Ofgem have created a number of artificial disconnects that adversely affect their ability to benchmark costs correctly. As a consequence:

- Ofgem's approach to unit cost benchmarking has removed some efficient costs (e.g. Civils) as a result of TOs submitting costs in different ways. This is due to different interpretations of what costs should have been mapped to a Lead Asset and what should have been mapped to Civils and elsewhere. The guidance provided in the RIGs and Glossary was ambiguous and, in places, contradictory. It is evident from submitted data sets that differences in interpretation have occurred and hence the subsequent steps in the process will not work as intended by Ofgem. For example, other companies have a significantly lower proportion of direct lead asset costs than NGET for what seem like very similar, in situ asset replacement interventions. Indeed, the gross costs of such interventions are very similar as illustrated in the chart below which compares a typical 275kV Transformer replacement scheme between National Grid and another company. The chart shows that the overall cost is similar between TOs, however the approach to categorising the cost has led to very different views of the direct costs associated with the lead asset.

[redacted]

The impact of this difference is that NGET's costs include a greater scope than the other TOs and are judged to be inefficient; these are then reduced. Meanwhile, the Civils costs are passed through the NLR PAM for other companies and their Direct Lead Asset cost appears efficient.

- The splitting of costs into Direct and Indirect means that the gross cost of delivering capital projects is not fully assessed. The unit cost process only assesses Direct asset costs such as transformers and non-asset costs such as civils. Indirect costs, such as design, network planning and project management, are assessed separately being classed as Indirect Opex. This approach prevents true calibration to historic performance as capital investment has traditionally been reported including all associated costs not just Direct costs.
- By introducing these requirements with little notice and requiring companies to submit historical data on the same basis, all companies have had to make assumptions to retrospectively create the required split in costs. This will introduce inconsistencies, which will have an impact on allowances because Ofgem select the lowest of historic and forecast unit costs when identifying their efficient unit costs.

If Ofgem had shared and consulted upon their cost assessment models prior to the final submission of data in December, companies could have helped improve the consistency of submitted data. This would have greatly improved the quality of Draft Determinations.

(i) Treatment of direct asset costs

These are submitted to Ofgem's benchmarking process, as described in the next step.

(ii) Treatment of Civils costs

Where expenditure was assessed using the PAM, Civils costs have largely passed through unaffected by Ofgem's benchmarks because they were unable to create consistent definitions for Civils (which is understandable because it is difficult to imagine repeatable units). However, again, NGET's NLRE has been treated inconsistently to the Scottish TOs and LRE because the application of ratios to our gross costs mean that our Civils costs have effectively been scaled in line with the direct lead asset benchmark.

(iii) Treatment of Other Costs

Where expenditure was assessed using the PAM, Other costs have largely passed through unaffected by Ofgem's benchmarks because they are (almost by definition) non-standard, non-asset cost. However, again, NGET's NLRE has been treated inconsistently to the Scottish TOs and LRE because the application of ratios to our gross costs mean that our Other Costs have effectively been scaled in line with the direct lead asset benchmark.

(iv) Treatment of Risk & Contingency costs

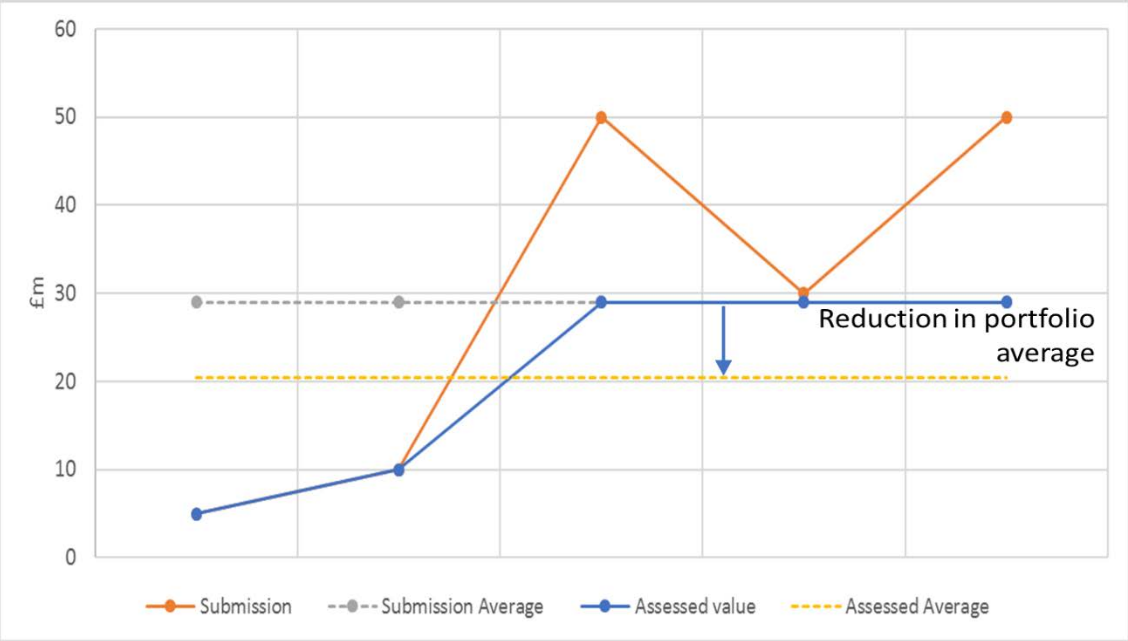
Ofgem's systemic reduction of risk and contingency costs is overly-simplistic (paragraph 3.27 of Sector Annex and 3.64 of NGET Annex). It is assumed that risk is incurred equally across all cost categories – asset, civils, other costs. Ofgem have removed any risk value apportioned to asset costs since these are benchmarked and the assumption is that any benchmark would include outturned risk values. This assumption is dependent on TOs consistently including risk in their asset costs in their T1 and T2 data sets where appropriate.

Any reductions caused by cost assessment have also been equally applied across all cost categories. However, a value associated with a particular risk event may only apply to one or two cost categories such as contaminated ground conditions likely to wholly impact civil costs. Where the risk would have impacted asset or indirect costs, which have been removed from the project for assessment purposes, the reduction is borne by the remaining cost categories in error.

Ofgem have assumed that the risk identified in a project is incurred in the T2 period – regardless of the phasing of a project. As such any adjustments following assessment of risk values have been made to the T2 allowances. This does not recognise projects crossing T1-T2 boundary and T2-T3 boundary. This approach has resulted in negative allowances in the T2 period.

Ofgem stated that risk was capped based on historic risk averages. In applying this in their calculations, they have firstly calculated the average based on the submission sample rather than the historic average. Secondly calculated the average through simple averaging of project risk %ges rather than calculating a weighted average across the sample. Finally in applying the cap, they have incorrectly applied the formula and so have not reduced projects to the calculated average risk %. Had this approach of capping at average been applied correctly it would lead TOs to a risk position that is lower than the average risk% previously experienced, since it does not recognise a portfolio position.

The chart below is an illustration of the effect of capping values above average but retaining values beneath the average unadjusted.



(v) Treatment of Indirects

Having introduced a change in the BPDT for T2 to require TOs to split out their Indirect costs from capital projects and report them on the CAI table, Ofgem have created a confusing format which has:

- Confused themselves. For example, in setting NLR allowances, Ofgem have applied reduction factors based on direct unit cost benchmarks to gross costs.
- Created benchmarking inconsistencies. For example, two projects covering identical scope with the same gross costs will have different Indirect costs if one is let as a turn-key contract to a Tier 1 supplier who manages all the site work and interfaces with subcontractors and the other uses in-house resource to manage a series of subcontractors. This means that the direct costs will be lower on the latter, dragging down the Direct Lead Asset unit cost benchmark, while the Indirects will be treated differently through the econometric benchmarking. Consumers are exposed to gross costs, and companies should be allowed to drive efficiencies in their gross costs by selecting the most appropriate delivery model over time.

To address this problem, Ofgem should benchmark gross costs, as they have done in previous price controls.

Stage 2. Create benchmark for direct asset unit costs

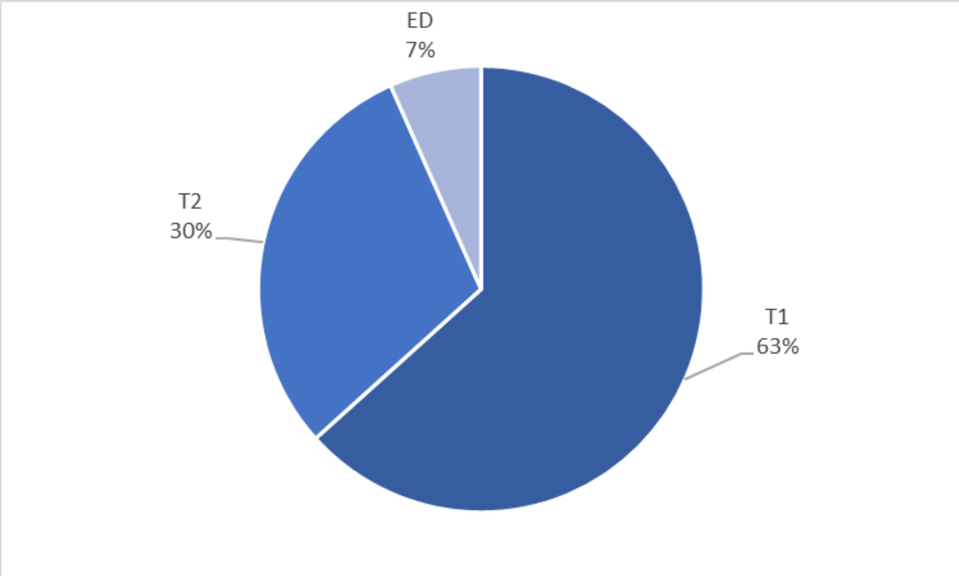
Ofgem have shared their approach to calculating their view of an efficient unit cost based on sector weighted means. While we can see the intention, we have concerns about the methodology:

- It is not clear that the dataset is giving a statistically robust benchmark. Only 30 of the 99 categories for which data was collected have resulted in what Ofgem have classified as a useable benchmark, and it is not evident what the criteria are for deciding that a benchmark is robust. For example, even where there are apparently good sample sizes, many have a standard deviation that is greater than the mean, i.e. negative unit costs are possible (see following table which includes units with a benchmark at 132kV and above;

values greater than 100% are highlighted in red). This is probably reflecting the fact that companies have submitted data for materially different interventions in the same asset category, which is a feature of the tables (e.g. all Protection and Control interventions are merged into a single row of the unit cost tables, regardless of whether a whole substation control system is being replaced or just a single sub-component). In addition, by using weighted means and standard deviations to assess the quality of their benchmarks, Ofgem are assuming that unit costs are normally distributed. There is no evidence that they have looked at other statistics such as kurtosis and skewedness; even if unit cost data has been collected on a consistent basis, a positive skew is probable and hence a median could be more appropriate.

[redacted]

- In taking the lowest of historic and forecast sector mean costs, Ofgem are ignoring underlying cost drivers such as technology and legislative changes that can and will change over the 15+ years that the datasets span.
    - The chart below shows the source of the selected benchmark unit cost, where a unit cost is judged to be valid. (This chart is based on a simple count of unit costs so takes no account of the relative value of the unit cost or the volumes of proposed interventions that it underpins.)
    - We make similar comments on opex, in that by anchoring to history, Ofgem are overlooking the evolution of the operating model, and gearing up of delivery across T1.



During the SQ process leading up to DD, Ofgem asked questions about why there might be a spread in submitted direct lead asset costs but refused to quantify the magnitude of this variation in any way (not even whether it was 10%, 100% or 1000% different). This made it effectively impossible for companies to provide suitable responses, because a 10% difference can be explained by genuine variation in local factors (such as physical accesses to site) or equipment specification (units with the same primary voltage but a different power rating) whereas a >1000% difference would indicate that there are fundamental differences in the input data. We have observed a number of issues which would have contributed to the spread of calculated unit costs in the cross-sector dataset:

- The spread of unit costs (e.g. a factor of 14,000 from the minimum to the maximum cost per circuit km for OHL Conductor) is a clear indication that the RIGs and Glossary were so ambiguous as to collect completely different interventions in a given asset category, meaning that the benchmark is poor. For example:
    - Other companies have put some cost from fittings only schemes against Conductor Replacement; this appears to reflect the cost of applying repair sleeves to cover broken strands which can be found when clamps are removed. This is not Conductor Replacement.
    - Other companies have put some cost from OHL conductor replacement schemes against Fittings Replacement (which can now be seen from C2.5/C2.5a) but NGET have not (as stated in the BPDT Narrative and on the Assumptions tab).
- Unit cost values derived are based on both load and non-load related schemes being proposed by the three TOs. Costs were not merged in this way in previous price controls, and will mean that fundamentally different interventions will be mixed together and treated the same. This leads to the incorrect averaging of costs to replace an existing asset with interventions which require the establishment of new infrastructure. Further details of this issue are provided in our response to NGETQ11.
- Ofgem's revised BPDT, Glossary and RIGs collect asset data based only on primary voltage. This means, for example, that significant cost drivers such as power rating are ignored. For example, NGET has a significant proportion of 400/275kV 1100MVA interbus transformers as well as 400/132kV 240MVA Grid Supply Point Transformers. The former are materially larger than the latter and cost more. This was submitted as evidence as part of our response to NGET_SQ_CA_125-127 during May 2020 but Ofgem have not

distinguished in setting allowances. (Ofgem confirmed on 5th August that they had taken into account our responses to SQs received up to and including 31st May 2020 but this is not apparent from the benchmark spreadsheets shared.)

- Ofgem have not assessed overhead line fittings with a consistent denominator. As was made clear in our BPDT narrative and Assumptions (tab A6), we reported Overhead Line Fittings replacement volumes as circuit km. Other companies submitted Fittings replacement volumes as per tower side (to a good approximation, there are three towers per km at 275 and 400kV so this will be a factor of three wrong).

Ofgem's benchmarking spreadsheets include the functionality to remove outliers and create "cleansed" weighted means. There is no evidence that Ofgem have used this function in setting DD allowances for NGET in spite of information provided through SQs.

If Ofgem had shared their cost models prior to the final submission of data in December, companies would have understood what was needed and could have helped improve the consistency of submitted data. This would have greatly improved the quality of Draft Determinations.

Stage 3. Apply project cost assessment model(s)

The Project Assessment Model (PAM) combines the company's Business Plan Data Template with Ofgem's unit cost model and Ofgem Engineering Hub's view of what volume and cost is justified for each scheme.

The Engineering Hub provides their view on scheme approval, whether a scheme should be part of baseline allowance or linked to an uncertainty mechanism, output delivery year, asset volumes, and justified costs for non-unit cost categories such as civil works. For approved baseline schemes, this model combines the costs deemed as justified by the engineers, with Ofgem's view of efficient costs for risk and contingency, and efficient costs for assets for which Ofgem has unit costs for (and passing through company values otherwise), to give an overall approved cost allowance per scheme. This allowance is then profiled across the years that the company has proposed its forecast and actual (where applicable) costs for the scheme using the same proportions as the company's profile.

(i) Investment passing through Ofgem's PAM

Our review of the LR PAM has revealed spreadsheet errors which we have identified to Ofgem. In addition, we have more general concerns about the methodology enshrined in PAM. For example:

- The systematic approach of reducing above-mean company costs to Ofgem's view of an efficient sector mean while passing through unadjusted below-mean costs means that even a company whose costs are on average lower than Ofgem's efficient sector mean will have their submission reduced if they have any spread in costs around the mean. The net result is that every company will have mean allowed unit costs that are lower than Ofgem's efficient sector mean. This approach does not recognise the natural spread of costs that would exist in any portfolio of work and perversely rewards companies whose costs are consistently higher than the sector mean.
- The unit cost assessment has been undertaken based on full project costs rather than the units still to be delivered. The simplifying assumption is made that the proportion different cost elements of a scheme (e.g. Other (Direct) £m) that occur within T2 is the same as the overall proportion of costs within T2 for that scheme. (This is implemented by Engineers_CostsView!Q referencing Comparison!P.) This is underpinned by an assumption that units are delivered equally across the phasing of a multiyear project. This assumption will not hold in many cases, and may be materially wrong for specific schemes. It does not take into account where investment is already committed and there is no opportunity to recover the efficiency. It also results in a project table that restates historic costs for a project, in some instances from before the start of RIIO-T1.

- Unit cost assessment has been applied to connection assets as well as those funded through T2 allowances. It is unclear why efficiencies have been applied to sole-user connection assets. In England & Wales, these costs and the associated income is treated as an Excluded Service. This means the customer pays a charge that reflects the actual costs incurred; as such this isn't subject to the revenue cap that Ofgem sets though the price control process. Customers are able to build their own connection assets if they can do this at a lower cost.

(ii) Investment not passing through Ofgem's PAM, i.e. NGET's NLRE

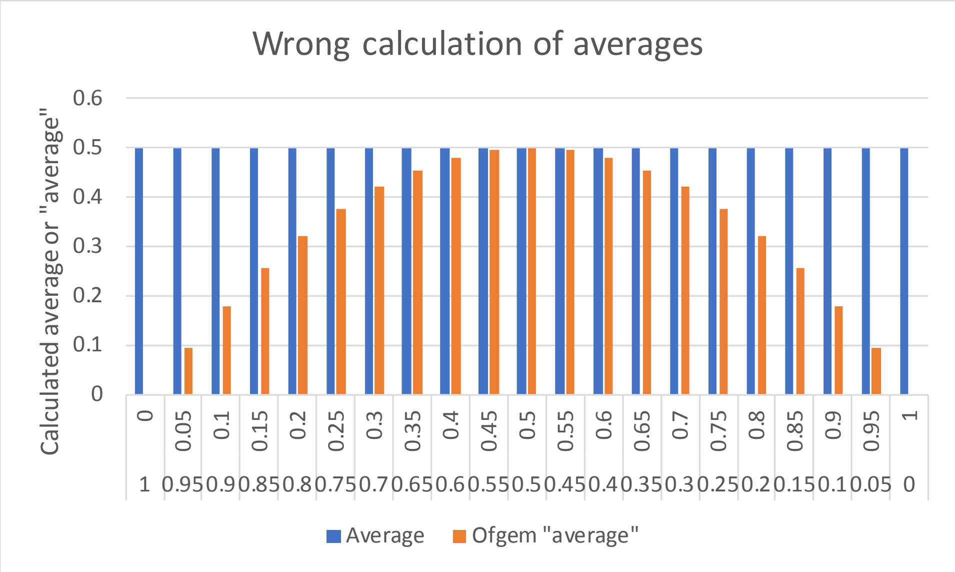
In paragraph 3.56 of the NGET Annex, Ofgem state that "Lack of clarity in the relationship between NGET's EJPs and the BPDT [which] prevented similar levels of cost analysis of NGET's plan in comparison to the other TOs." More specifically, paragraph 3.62. states that "In light of the portfolio approach taken by NGET in compiling its BPDT for NLRE, we were unable to directly apply our model for assessing costs." Consequently, paragraph 3.63 says "We have used a combination of approaches to come to a view on efficient costs of asset interventions that passed the needs case assessment[51]". "[51] This is similar to the approach used for other Licensees, albeit for their submissions our model automated this process. For NGET these works were undertaken manually where possible."

In carrying out these manual adjustments, a number of process and mathematical mistakes were made.

- Ofgem have applied their view of efficient sector mean unit costs to NLRE, even when their own benchmarking analysis indicated that the dataset was not suitable for use and should not be used. This did not impact the DD allowances for LRE or the Scottish companies because the Project Assessment Model (PAM) passed their costs in these categories through unadjusted but was responsible for 85% of the cost assessment reductions to Ofgem's NLRE. NGET have therefore been treated inconsistently to other companies through the application of invalid cost benchmarks.

Asset	[redacted]	**Ofgem Default_UC (Column N)**
SGT	[redacted]	Yes for 400, 275 & 132kV
OHL Conductor	[redacted]	No Ofgem UC
OHL Fittings	[redacted]	No Ofgem UC
Cables Non-Lead	[redacted]	Yes for 132kV, but all these are <=66kV
Reactors	[redacted]	No Ofgem UC
Protection & Control	[redacted]	No Ofgem UC
Instrument Transformers	[redacted]	No Ofgem UC

- Where Default UC outputs exist, Ofgem have used a different version to that supplied on 29 July as the official and consistent dataset (Unit_Cost_OfgemView_v1).
- In calculating their 'Reduction Factor', Ofgem have inverted the ratio, averaged it and inverted it again. This will only correctly calculate the average of two identical numbers; for all other cases, the answer will be lower than the true average. The graph illustrates this for number pairs that average to 0.5 (from 1,0 to 0.5,0.5 to 0,1 as shown by the horizontal and vertical numbers on the x axis).



In addition to the above generic points, there are a number of other errors and inconsistencies in the setting of NLR DD Final Allowances. These are discussed in more detail in our response to the NGET Annex questions NGETQ11 and NGETQ12.

External views

Given our extensive concerns about Ofgem's approach to the cost assessment of network capex, NGET commissioned an independent engineering consultant (Mott MacDonald) to review two questions:

- Is Ofgem's cost assessment methodology correct in principle?
- Have Ofgem correctly applied their methodology?

A synopsis of their report has been submitted alongside our response and a full confidential report will be submitted to Ofgem. (The latter cannot be published because it contains details of commercially-confidential cost information.) Their summary findings are as follows:

> *The three-step sequence to setting allowances as set out by Ofgem was appropriate. The sequence involved reviewing the justification for interventions; then reviewing the asset additions and disposals required to carry out each justified intervention; then evaluating the efficient cost to deliver those asset additions and disposals. However, Ofgem only appeared to follow its stated three-step cost assessment sequence in the case of Load Related Expenditure.*
>
> *The approach is dependent on having an appropriate unit cost dataset to assess against, relying on asset categories being well defined and appropriate. We have reviewed a small sample of six schemes, which nevertheless amount to £57.7m of discrepancy between Ofgem's view of efficient costs and NGET's estimates of required Load-Related investment. In these examples, we have identified that greater disaggregation within the categories of 275kV CB (Air Insulated Busbars) (OD) and 400kV CB (Air Insulated Busbars) (OD) could potentially be used to reach agreement between NGET and Ofgem on efficient costs.*
>
> *Ofgem did not effectively validate results from its cost assessment model for Non-Load Related schemes. In one worked example of a transformer replacement project which we*

examined, the allowance for the overall project inclusive of pre-construction, civils, indirects, risk and contingency was less than Ofgem's efficient unit cost for the Lead Asset itself. In one worked example of an overhead line re-conductoring scheme, the project budget appears to have been cut to a level which, even at Ofgem's efficient unit costs, would cover only 61% of the route. As such, these results are not consistent with Ofgem's own analysis.

Mott MacDonald has been able to identify these discrepancies by re-aggregating costs at project level and carrying out a reasonableness test.

<u>Conclusion for network capex cost assessment</u>

Fundamentally, Ofgem's approach to establish the efficient cost of projects by:

(i) Calculating weighted average sector unit costs and using the lowest of historic vs forecast as their view of an efficient unit cost benchmark;
(ii) Applying these benchmark unit costs to the approved project scope (asset volumes), comparing their view of the benchmark cost with the submitted cost and choosing the lowest;
(iii) Assessing the capitisable Indirect costs separately via a flawed econometric model; and
(iv) Overlaying a further ongoing capex efficiency of 1.2% year-on-year

results in 'efficient costs' that don't allow whole projects to be delivered.

The cost assessment processes resulted in a network capex cost reduction of £417m (11% of the load-related plan and 19% of the non-load related plan). Our view is that these reductions do not reflect genuine efficiencies but instead are a result of the errors and inconsistencies in the analysis undertaken for Draft Determinations. Major improvements will be achieved by treating as much of the NLR plan as possible in a consistent fashion (and we are working with Ofgem to ensure that recut data cost data will flow into the PAM) but the correct grouping of asset costs and appropriate treatment of outliers are also important to resolve.

Network Operating Costs (NOCs)

Challenges with tables of mixed composition

Our substantive position on Ofgem's approach to assessing NOCs can be found in our response to question NGETQ14 within our response to the NGET specific annex. We summarise our view below.

Ofgem's T2 regulatory Reporting Instructions and Guidance (RIGs) stipulations, coupled with the totex-based orientation of its Business Plan Data Tables (BPDTs), mean that the Repairs & Maintenance and Legal & Safety subcategories of NOCs are comprised of both opex and capex components. We understand that this is not unique to our submission, with SPT and SHET's submissions for NOC also having a blend of opex and capex activity.

Our capital plan submission was supported by a series of Investment Decision Packs (IDPs) which have an asset / investment type orientation and provide justification for the expenditure proposed. Expenditure on certain asset types are grouped together in the IDPs, however interpretation of the RIGs means that a single IDP can straddle multiple BPDTs. As illustrated in table below, a single IDP may not exclusively relate to NOCs categories, including elements that are contained within the Non-Load Related Capex submission.

This has proven to be problematic for Ofgem's Engineering Team, who provided feedback that our submission was difficult to understand and interpret, also expressing a concern of overlaps or double counts in our submission. This has led to a partially completed cost assessment for the capex elements of Repairs & Maintenance and Legal & Safety feeding into Ofgem's draft determinations, with the opex elements of these tables effectively unaddressed. We are actively working with Ofgem's Engineering and Cost Assessment teams to resolve this.

Ofgem's stated cost assessment methodology describes the difference in approach for capex and direct opex, however, we do not believe Ofgem's processes are geared to situations where individual data tables contain a mixture of opex and capex items.

We are working with Ofgem's Engineering and Cost Assessment teams to provide the line item granularity required to complete the assessment of the capex and opex elements separately. This includes providing detailed mapping of IDPs to BPDTs for the capex elements and providing opex only views of the affected tables, as well as a consolidated supplementary NOC annex. We think this issue could have been avoided with clear distinction of opex and capex cost items within the structure of Ofgem's ET BPDTs, as has been retained within the GT counterparts.

Providing Ofgem with additional clarity on the scope and boundary of the NOC capex components still leaves remaining issues as to how these should be assessed. The inference is that these would follow the approach intended for direct opex, which we note would be inconsistent with the treatment of other capex. Again, we will continue to engage with Ofgem's teams on this ahead of final determinations.

Approach to assessing the direct opex elements of NOC

Setting aside the issues above, we observe that Ofgem's cost assessment for direct opex is very much anchored to T1 performance, and involves the following steps:

i) Calculation of a unit cost for each subcategory of NOCs at the disaggregated level observed historically over the six-year T1 period to date

ii) Calculation of the average T2 unit cost forecast per submissions at same level of disaggregation

iii) The minimum of the T1 observed or T2 forecast unit cost is taken

iv) The minimum unit cost from (iii) is then multiplied by the network's view of forecast volumes

   i) Where volumes are not reported, the same approach is taken but with average annual expenditure instead of unit costs

This is a highly mechanised approach which presents pitfalls if used in isolation:

- Ofgem should be cognisant that the T2 volume data requirements are a new requirement, and not part of T1 Regulatory Reporting. This has required networks to derive a volume history retrospectively, as described in our NOC supplemental annex. Ofgem should take this into consideration in its unit cost appraisal, and cross check its line item level appraisal against a table level review.
- By anchoring its assessment to the average T1 spend, this mechanised approach overlooks the case made for specific upward cost pressures we foresee in T2. Details of these were provided in our original submission but have been reconfirmed with additional narrative in our supplementary NOC annex.
- Furthermore, T1 actual positions could be affected by non-recurring factors that might suppress one particular year of performance, but do not endure on an underlying basis. Anchoring the T2 appraisal to the lowest position in T1 could therefore incorrectly assume that these factors are present on an enduring underlying basis.
- It is also important to note that network operating models evolve over time, so to anchor to a low point in T1 at line level may result in an outcome that does not reflect the ongoing steady state.
- Unlike the assessment of capex, Ofgem performed its direct opex assessment inclusive of efficiencies that are embedded into forward cost projections. The outcome is then fed into a separate calculation of ongoing efficiencies, giving rise to the likelihood of a double count with network's own proposals in this regard. It is vital that Ofgem duly considers the sequenced formulation of our plan in its appraisal, which can be summarised as follows:

i) Our underlying forward cost projections were baselined to 2018/19 performance, exclusive of exceptional severance costs arising in that year. This reflects an underlying position reflective of the current shape of the organisation, and the optimal level of unit cost efficiency achieved in T1 to that point.

ii) We separately considered upward cost driver risks, overlaying these to the underlying position in T1. We should stress that these are specific cost pressures that would not be captured through general inflation uplift, RPEs, or Ofgem's proposed NOC opex escalator.

iii) Our projections were then overlaid with enduring efficiencies we expect to deliver from 2019/20 onwards, the value of which was higher than our on-going efficiency assumption for the RIIO-2 period. There is therefore overlap with Ofgem's separately calculated ongoing efficiency target, which effectively runs from 2019/20, with two years of compound efficiency carried throughout the T2 period.

iv) We applied an ongoing efficiency assumption of 1.1% from 2021/22 onwards based on closing T1 levels inclusive of embedded efficiencies to this point. Again, this overlaps with Ofgem's own ongoing efficiency proposals

It is therefore important that Ofgem's cost assessment takes due consideration of our plan build process to correctly assess upward cost pressures and ensure that embedded efficiencies are not double counted within Ofgem's separately-calculated ongoing efficiency target.

There is a logical way to navigate through these issues to arrive at an appropriate assessment of direct opex that is more consistent with the approach for capex, and that allows Ofgem to overlay its ongoing efficiency challenge without risk of double count. This would take the following steps:

1. Assessment of our submission on an underlying basis exclusive of T2 upward cost pressures and efficiencies embedded from 2019/20 onwards in the first instance.
2. The appropriate reference point for the T2 appraisal is 2018/19 exclusive of exceptional severance costs, and not any position prior to this. This reflects the current shape of our organisation, and a position of optimal unit cost performance in T1 up to this point. This also solves the issue of non-recurring factors affecting reported positions in the years prior to 2018/19 – any alternative approaches to addressing this issue would be complex, involving explicit adjustment for agreed items, and a risk of being non-exhaustive.
3. Whilst we think our proposal would negate issues involved with retrospectively creating volume history, for the avoidance of doubt, a table level cross check of outcomes could be made against the line level assessment.
4. We think it is inappropriate that the effects of specific upward cost drivers are rolled into Ofgem's unit cost assessment, as they could be systematically discounted through reference to lower 2018/19 positions, and automatically and unduly be deemed as inefficient. We therefore propose that the case made for these is separately reviewed and overlaid to the outcome of steps 1 to 3.
5. The outcome of step 4 can then be subject to Ofgem's ongoing efficiency calculation.
6. Given the strength of our embedded efficiency proposals from 2019/20 onwards, there is a possibility that this will result in outcomes higher than our cost proposals. If this is the case, we propose that Ofgem defaults to the lower of steps 1 – 5 and our original proposals.

We think this approach resolves a number of the pitfalls associated with Ofgem's stated cost assessment methodology for direct opex, retaining a core element of initial core modelling, but overlaid with suitable cross checks and overrides where appropriate.

This approach would require submission of specific recuts of our data submission, which we have committed to providing to Ofgem. Based on engagement with Ofgem's cost assessment team, an opex only view of the submission for Repairs and Maintenance and Legal & Safety would be required in any event in order for it to carry out its stated cost assessment methodology, given mixed table composition issues highlighted previously.

Operational Protections Measures and Operational IT Capex

Our December Business Plan Submission identified a requirement for £186.9m capex investment for OpTel Refresh, with £108.9mm identified for Telecoms equipment replacement, implementation of a high bandwidth overlay and other enhancements and £78m to replace fibre-wrap which is approaching the end of its service life. Ofgem's Draft Determination 'does not fully accept the need case for OpTel refresh at present' and does not differentiate between fibre-wrap and telecoms equipment refresh and proposes £62.1m allowance a 'to enable works to begin'. This represents a reduction of 67% and will mean that obsolete telecoms equipment will remain in service presenting a significant risk to the reliability and resilience of the electricity transmission network.

The OpTel network is a highly resilient telecommunications network providing secure connectivity between substations and control rooms, and connects DNO's, Generators and TO's in Scotland. OpTel underpins critical tele-protection services and network monitoring and control (services and is essential to the safe, secure, reliable and economic operation of the electricity transmission network. [redacted]

Loss or compromise of the OpTel network could lead to a loss of visibility, control and protection of our sites, resulting in a partial or complete loss of supply. In the event of a Black Start event OptTel provides the secure communication channels that enable us to effectively coordinate activities to restore electricity transmission when other communications networks are not available due to loss of electricity supplies.

The OpTel Telecoms equipment was installed between 2011-14 and some assets will be over 15 years old by the end of T2 when Telecoms operators typically replace after 10 years. We are extremely concerned that the consequence of reduced and/or delayed funding will mean that obsolete telecoms equipment remains in service into the T3 period with an unacceptably high risk of in-service failure and an increased cyber security risk to this CNI designated asset, which poses a serious risk to the reliability and resilience of the electricity transmission network.

Following submission of our Business Plan in December 2019 we have been working on our approach to OpTel telecoms equipment and fibre-wrap replacement. Recognising the different drivers for telecoms equipment refresh and fibre-wrap replacement we have split these into discrete projects and provided supplementary evidence to Ofgem in support of our plans. We believe that it is essential that the obsolete telecoms equipment is replaced as per our Business Plan Submission and have been working to develop a revised approach for fibre-wrap replacement using enhanced condition monitoring and an innovative approach to fibre-wrap deployment, which requires reduced investment and system access in the T2 period. This approach will enable ageing fibre-wrap to be prioritised and replaced over a seven-year programme at the lowest cost to the end consumer and with minimal system outage requirements, ensuring that the reliability and resilience of this essential service is maintained. The High Bandwidth Overlay (HBO) is required to meet growing demand for capacity due to additional services eg cyber security of operational technology (OT) and increasing data volumes eg asset condition data. The HBO is not constrained by the fibre-wrap replacement programme as stated in the Atkins Engineering report and is most efficiently delivered as part of the Telecoms equipment refresh works.

Indirect opex

We address Ofgem's assessment of Closely associated indirect (CAI) costs, which encompasses both opex and capitalised indirect labour costs, and Business Support costs in detail as part of our response to NGETQ15. However, we also provide a summary here of our views with respect to the key elements of this approach as set out by Ofgem in the ET sector annex.

We do not agree that ET and GT sectors should be pooled together into a single regression analysis. Commonality of closely associated indirect (CAI) sub-categories between GT and ET sectors, and similar trends in Business Support Costs (BSC) do not in themselves demonstrate suitability for pooling of the two sectors. In their assessment of Ofgem's approach NERA demonstrate statistically that the GT sector has a different relationship to CAI and BSC costs than the ET sector, a difference which Ofgem's preferred CAI and BSC models fail to take into account and so inadequately modelling efficient costs. Further detail on this can be found in our response to NGETQ15.

We agree with Ofgem's decision to allow our IT & telecoms in line with Atkins' assessment. Our IT operational costs reflect the costs of supporting our IT systems and we submitted evidence of the efficiency of our costs going into RIIO-2 in the form of a comprehensive benchmarking review performed by independent experts Gartner. We embedded our ambitious ongoing efficiency commitment of 1.1% per annum into our IT operating costs which more than offset the incremental costs of new investments we proposed in RIIO-2.

We do not agree that forecast efficient insurance costs can be predicted from historic costs. Over 95% of our insurance costs are premiums which are externally driven and forecast to rise over the RIIO-2 period due to market distress. We provided evidence from two independent insurance brokers who estimated that commercial premiums would be over 30% more than our proposed premiums for RIIO-2. Ofgem should assess insurance costs separately, in line with their approach in RIIO-T1 and in recognition of the future expectations of premiums over the RIIO-2 period.

In our response to NGETQ15 we provide evidence to support a number of concerns with Ofgem's preferred models for CAI and BSC costs, in addition to the assumption of comparability of sectors above.

- Allowances have been set based on observations from only six years of RIIO-1 costs for the four Transmission networks, resulting in a wide dispersion of apparent efficiency gaps because there is not sufficient data to reliably estimate efficient costs.
- Ofgem's preferred models fail important statistical tests and so are subject to error and bias in their estimation of true efficient costs, leading to disallowances that are too high.;
- The coefficients used by Ofgem to set allowances are highly sensitive to modelling decisions around the treatment of scale effects and choice of cost drivers making it impossible to conclude where the true efficient view of costs lies, for example by selecting alternative modelling approaches that still meet Ofgem's model selection criteria the efficiency score for NGET CAI costs in RIIO-2 could fall anywhere between 0.91 to 3.58.
- Ofgem has used the results from these models directly to set allowances and has failed to consider evidence we submitted to demonstrate the efficiency of our underlying costs. This is particular concerning in cases where we forecast increases in cost drivers, such as rising insurance premiums and the costs of carbon offsetting, despite Ofgem agreeing to the need for those higher levels of cost drivers elsewhere in their determinations such as the costs we need to take forward our Environmental Action Plan commitments.

Our concerns are supported by an independent review of the indirect modelling approach, conducted by NERA and we submit their report as part of our response.

In adopting this approach for the first time to assess Transmission indirect costs Ofgem have gone against their stated intent to "adapt the RIIO-ET1 cost assessment process, as appropriate, rather than establish a new approach for RIIO-ET2". Earlier engagement on indirect cost assessment methodology, for example as part of the RIIO-2 tools for cost assessment consultation in August 2019, would have helped Ofgem gather views from networks and other stakeholders and develop a more robust cost assessment methodology than the one they have relied on in their draft determinations.

In reaching their Final Determination, Ofgem should heed the advice of their consultants to recognise the limitations of econometric modelling as a tool for assessing efficient costs in Transmission networks and instead set allowances based on consideration of evidence submitted by networks for the efficiency of their proposed expenditure in RIIO-2.

Ongoing efficiency

Our substantive position on Ofgem's approach to ongoing efficiency can be found in our responses to questions 10 and 11 of the core consultation document. We summarise our view below.

Ofgem's proposal for 1.2% (capex) and 1.4% (opex) per annum ongoing efficiency targets place excessive stretch on top of its already unprecedented and unjustified efficiency challenges to networks costs. These targets are above regulatory precedent, including those applied recently in the water sector, and seek higher than historical productivity gains from networks during a period of sustained low general productivity and with significant future uncertainty around Brexit and Covid-19 economic impacts. The 0.2% innovation adjustment is without basis, double counting gains already embedded in our business plan and acting to further increase the error in Ofgem's selected target.

We embedded a stretching 1.1% future productivity target across our operating costs and capitalised labour costs in our business plan; the highest target of all networks' business plans and aligned to the recent water sector target. This was on top of compelling enduring savings we expect to deliver by the end of the T1 period. Our proposal was linked to our request for a fixed labour RPE allowance, in recognition of the more specialised and long-term dynamics of our workforce and the greater role that networks can play in managing pay. It was also linked to the evidence we submitted that our business plan costs were at the efficient frontier as we started the T2 period. We did not place any ongoing efficiency target on our direct capex in recognition of the fact that our direct capex costs represent the cost of our third-party contractors and supply chain, and their expected level of productivity was already embedded within RPE indices and / or CPIH.

Despite this, Ofgem has proposed to add an even greater degree of stretch to our costs. This is unjustified. Firstly, Ofgem's estimates of the size ongoing efficiency is inconsistent with current economic trends and regulatory precedent. Ofgem's proposed ongoing efficiency challenge:

- Is based on a flawed range of estimates that are inconsistently calculated and not prepared on a basis that is consistent with regulatory precedent. For example, by:
    - Taking an unweighted view of historic productivity trends resulting in 50% of productivity data points relating to pre-financial crisis period and so downplaying the importance of more recent sustained lower productivity growth;
    - Using a wide range of industries encompassing poor comparators for energy networks, such as agriculture, accommodation and food services and arts and entertainment industries.
    - Placing more weight on higher but less reliable "value-added" measures of productivity and downplaying the more reliable "gross output" measure of productivity that takes greater prominence in regulatory decisions.
    - Compounding this issue of placing more weight on "value added" by then applying the measure across all inputs rather than those to which specifically relate to the Value-Added measure (i.e. those which do not include intermediate inputs such as our contractor delivered capex).
- Dismisses the potential impact of future economic uncertainties that prevail through the RIIO-2 period, for example:

- o Incorrectly interpreting rising Office of Budget Responsibility (OBR) forecasts as a sign of expected economic recovery rather than a result of their forecasting methodology, which seeks return to a steady state level of productivity and has resulted in several revisions as recovery has yet to materialise;
- o Does not consider most recent Bank of England (BoE) forecasts that incorporate Covid-19 and other latest impacts to the economy and forecast only 0.75% growth over the next 18 months.

Secondly, Ofgem adds a further 0.2% innovation adjustment to its efficiency target which is without basis and makes the same error in failing to assess the extent to which networks have already embedded benefits that was made for RIIO-ED1 Smart Grid Benefits. Ofgem fail to recognise that;

- Innovation projects are undertaken for a range of reasons, not solely financial. Of the £88.5m NIC funded innovation projects in RIIO-1 less than £10m was directed to projects primarily focused on reducing price control costs;
- The fact that innovation stimulus has been needed in the energy sector points to lower than general levels of innovation occurring than in the general economy; to the extent to which innovation gives rise to financial benefits these will already be reflected in the general economic productivity targets;
- Any financial benefits identified from RIIO-1 innovation are already embedded in our business plan costs, we provided evidence that our RIIO-2 plans benefitted from £707m of reduced or avoided capex costs from RIIO-1 innovation and efficiencies;
- Notwithstanding the flaws above, the 0.2% is based on a notional expected return to consumers rather than what an efficient company could reasonably achieve and ignores the 10% contribution networks make to the funding of NIA projects, plus the compulsory contributions made to NIC funding

Ofgem layer this challenge this on top of unprecedent and unjustified efficiency disallowances across our business plan, resulting in efficiencies that add up to £1bn across the period.

Our business plan proposals made a link between long term input price influences on labour, with a long term view on productivity, and we think this approach addresses considerations for economic uncertainty during RIIO-T2, and the extent to which these may or may not impact transmission network companies, and in or response to Q10 on Real Price Effects, we ask that Ofgem consider the merits of this approach in the unprecedented circumstances we face. We also suggest that they may be merit in taking a net nil view on labour RPEs and ongoing efficiency given their close parity, leaving only external capex costs subject to RPE indexation, which we consider also capture the productivity gains of external companies.

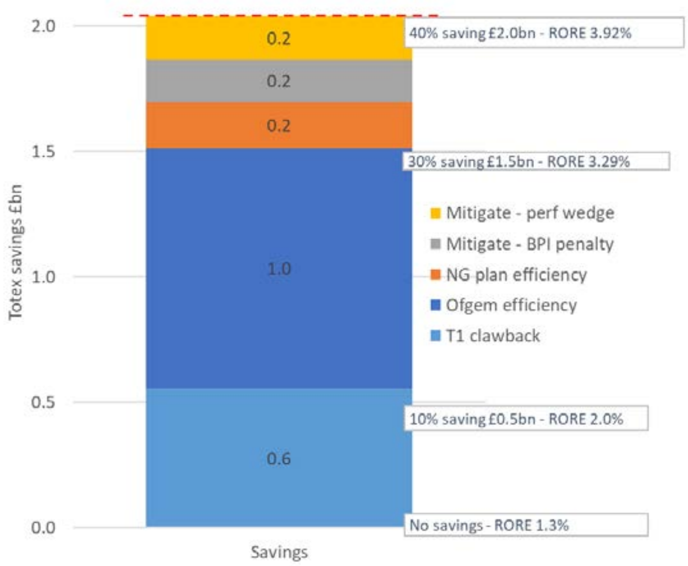
Overall impact on allowances

Ofgem's Draft Determination has resulted in totex disallowances that are a world apart from previous regulatory decisions, with a total of £4.8bn of costs disallowed equating to a reduction of 48% across Transmission. NGET starts RIIO-2 with allowances of under half of its RIIO-1 spend to run and maintain the transmission network. A large part of this reduction is an unprecedented and unjustified 20% cost efficiency against the allowed volume. We set out the evidence for why this level of efficiency is unjustified in response to NGETQ11 to 16 in the NGET document. This is the equivalent of £1.0bn totex savings across the period. If we were to deliver no savings from our current operations this would result in a 119 basis points underperformance.

We had already embedded totex efficiencies of £0.2bn into our plan, including the highest productivity assumption across all networks and the savings from our ambitious end of RIIO-1 period restructure. These have not been fully delivered yet and add 24bps to the challenge from our current cost base.

The downside risk before RIIO-2 even starts is represented by the graph below which shows that to close the gap to allowed return we would have to deliver the volume of work allowed in DD for 40% less than our current operations.

Starting RoRE and totex savings gap to deliver allowed equity return



ETQ10 Do you agree with our proposed eligibility criteria for the LOTI re-opener and do you agree with the assessment stages, and their associated timings?

We have concerns over the associated timings of assessment stages. Our response to this question sets out: (1) context, (2) T1 approach and our T2 proposal, (3) the draft determination (4) our views on the DD, (5) developments since DD.

We note this area interacts heavily with ETQ11*. Do you agree with our proposed definition of PCF for RIIO-2, and the areas of work that we intend that definition to cover?* and ETQ12. *Do you agree with our proposal to assess PCF costs as part of RIIO-2 Closeout, following the principles set out in Chapter 4?.* We cross reference responses where relevant.

1. Context

Most reinforcements of the transmission network are small and incremental, but the drive to decarbonise electricity has led to the need for more large strategic projects. These projects enable the connection of generation and interconnectors with neighbouring markets, often located on the extremities of the network, and transport power from where it is produced to where it is consumed at lowest cost. They are often on the critical path to connecting low-carbon sources of electricity and can reduce the overall cost of electricity transmission by tens to hundreds of millions of pounds a year for consumers by reducing the ESO's operational costs when balancing generation and demand.

These large projects naturally lend themselves to a different regulatory approach that allows for appropriate regulatory scrutiny on behalf of consumers and for increasing competition in delivery.

We are strong advocates of a Competitively Appointed Transmission Owner (CATO) approach to competition for its potential to add consumer value in many cases.

2. T1 approach and our T2 proposal

The Strategic Wider Works (SWW) mechanism is used to fund large network reinforcements in the T1 period. The threshold for the SWW re-opener varies across the TOs to reflect regional differences with thresholds of £50m, £100m and £500m in place for SHETL, SPT and NGET respectively.

The SWW process evolved over the T1 period from a three-stage process in the original 2013 guidance to a four-stage process of (i) eligibility, (ii) initial need case, (iii) final need case and (iv) project assessment in the updated 2017 guidance. These steps are described in the SWW guidance documents, not the TO's transmission Licences.

The sector specific methodology decision did not establish policy for large strategic projects in the RIIO-2 period and informal development of an approach was only in the early stages when we submitted our business plan. We therefore based our business plan on the assumption that the T1 SWW arrangements would continue into the T2 period in some form.

3. The draft determination

Ofgem aim to ensure that they, "*are able to effectively scrutinise LOTI investments on behalf of consumers while providing the TOs with a process which enables them to progress projects effectively"* (ET Annex, Para 4.26). To do this the Draft Determination proposes to replicate much of the T1 SWW mechanism policy intent and mechanics with a new Large Onshore Transmission Investment (LOTI) mechanism, incorporating learnings from RIIO-1, with the following characteristics:

i. A harmonised £100m threshold across TOs;
ii. Covering projects in the following categories: (i) boundary reinforcements, (ii) generator and demand connection projects and (iii) projects relating to asset health;
iii. Applications to the process can be made at any time in T2
iv. Following a more prescriptive three-step process, preceded by an eligibility stage, of (i) initial needs case - INC, (ii) final needs case - FNC and (iii) project assessment - PA, that "*will only be amended in very rare cases*";
v. Where the earliest and latest a decision will be made on whether the project is suitable for late competition is at the INC and FNC stages respectively; and
vi. Where projects currently being assessed through the SWW process will transition to be assessed under LOTI if they have not yet received funding.

The process set out in the Draft Determination is as shown in the table below (adapted from Table 18: LOTI assessment process of the ET Annex), except for the "approval of eligibility to apply stage", which did not appear in the Draft Determination and has been extracted from the current draft Licence Condition for LOTI.

Stage	Submission Timing	Assessment	Output
Approval of eligibility to apply*	Not less than 6 months before Initial Needs Case submission	(up to 6 months) focussed on whether project falls within LOTI scope and standard timings	Approval to submit Initial Needs Case
Initial Needs Case (INC)	Not less than 12 months before TO final statutory planning consultation	6 – 12 months focussed on main drivers of need and optioneering	Ofgem views. No formal decision. (+ earliest decision point on whether project goes to competition)
Final Needs Case (FNC)	After TO has secured all material planning consents	3 – 6 months focussed on key drivers of need and	Ofgem decision on project need (+ latest decision point

		whether INC views have been factored in	on whether project goes to competition)
Project Assessment (PA)	After FNC and majority of procurement finalised	6 – 12 months focussed on detailed project costs TO seeking allowances for	Ofgem decision on funding allowance

*details taken from current draft of the LOTI licence condition – Part C: Approval of eligibility to apply

The Draft Determination indicates that LOTI guidance will be consulted on and published ahead of RIIO-2.

4. Our views on the draft determination

The proposed LOTI mechanism and process needs to be reviewed alongside several other interactive policy areas in the Draft Determination when considering whether it meets the aim of allowing for effective scrutiny and providing a process that enables TOs to progress projects effectively. Interactive policy areas include: Increasing competition – p.108 Core Document, Large project delivery – p.25 ET Annex and Pre-construction funding – p.71 ET Annex.

Whilst we agree with the principles of a LOTI re-opener mechanism that builds on the policy intent and mechanics of SWW, the Draft Determination represents a rigid and cumbersome process that is insufficiently agile to allow TOs to enable net-zero. We disagree with the proposal to include asset health related projects under LOTI. In addition, the lack of published guidance materials means there is uncertainty over how many specific aspects of LOTI will operate. Consideration alongside other interactive policy areas exacerbates these concerns.

We set out our detailed views on each aspect of the Draft Determination, below:

(i) Re-opener windows and thresholds

We agree that it is appropriate that the LOTI mechanism does not follow the proposed common approach to other T2 re-openers. Allowing for submissions at any time (i.e. no fixed re-opener window) will allow these critical net-zero projects to start the process when required and a threshold of £100m aligns well with late-model competition criteria and represents a sensible level at which to apply additional scrutiny on behalf of consumers.

This reduction in the threshold in England & Wales will mean that the LOTI mechanism applies to projects with different characteristics than those captured by the previous threshold of £500m.

The process needs to be sufficiently flexible to cater for these different project types and ensure there are no unnecessary delays as a result of the regulatory process.

The ongoing Licence drafting activity for LOTI must clearly address any assumptions related to indexing of the £100m threshold. Is this threshold on a given price base or simply the current day cost assumption of a project when an eligibility assessment is made?

(ii) Project coverage

Application of the LOTI mechanism to boundary capability projects and generation and demand connections is a sensible extension of the SWW approach in T1.

The application of LOTI to asset health driven investments is an unexpected policy development in the Draft Determination. Our understanding is that LOTI is designed to manage uncertainty, principally of need. This applies well to load driven schemes where the scope and timing have a greater element of uncertainty than asset health driven schemes as load schemes often rely on many issues outside the normal expertise of transmission. However, for asset health schemes the situation is different. As assets owners TOs are best placed to manage risks in this area and as there is no dependence on customer actions the need is more certain.

From the LOTI working groups that took place prior to publication of DD, we understood that these types of investments were to be explicitly excluded from the mechanism. Our response to Q32 of the Core Document describes why asset health investments such as our Dinorwig-Pentir project, should not fall under the coverage of the LOTI mechanism because they generally involve the like-for-like replacement of existing assets and therefore:

- they do not generally require NGET to obtain any planning consents as these will already be in place for the existing asset;
- there is unlikely to be a range of options available that must be assessed and compared, generally NGET will have the option of doing nothing or carrying out a like for like replacement;
- as a result of the two characteristics described above, asset health driven schemes tend to have much shorter development and delivery timescales than large customer driven schemes that may require extensive optioneering and consenting activity. The proposed LOTI timescale and milestones do not align with, or facilitate, the process of developing and delivering an asset health related investment;
- NGET undertakes a high volume of asset health related investments to maintain network reliability, the coordinated planning of these is vital to ensure that works can be delivered with minimal effect on the ESO's network operating costs and our customer's access to the network. We manage this through detailed understanding of asset condition, available system access, and availability of key resources. This optimisation cannot be done on an asset by asset basis but rather must be done at a portfolio level. The proscriptive nature of the LOTI process would inhibit this ability to optimise our plan resulting in suboptimal timing and allocation of resource and introducing a significant degree of uncertainty into this process that does not currently exist.

It is our view that there is limited consumer benefit to be gained for assessing asset health driven projects through the LOTI process. The limited options that are typically available and the much shorter deliver timescales make these schemes fundamentally different to load driven large projects that require planning consent. Any value that could be gained through further scrutiny for options and costs in LOTI would not out-weigh the negative effects for the consumer of reducing NGET's ability to progress the most efficient asset health plan and maintain network reliability.

The LOTI process is not suitable for asset health investments and should be limited to boundary capability and generation and demand connection projects, as with SWW in the T1 period.

(iii) The LOTI process

We agree with the three stages outlined as part of the LOTI process, plus the eligibility stage, as these are broadly aligned to the existing SWW mechanism.

However, we believe the delivery of LOTI projects will be delayed as a result of Ofgem's proposed process. This is caused by (a) the proposed generic milestones and timings set out in the Draft Determination are too rigid and prescriptive (particularly given the proposal to include these in our Licence), (b) the total assessment time, at up to 30+ months is too long, and (c) the interaction with other policy areas such as competition, pre-construction funding, and late project delivery further restrict which activities can take place when and/or introduce uncertainty and risk around funding that network companies may seek to mitigate through extended project timelines.

<u>(a) Milestones and timings</u>

Whilst we understand the desire to set clear expectations around timings the generic process proposed to be applied to all projects >£100m, with its rigid and prescriptive milestones, is not commensurate with the varying characteristics of the project types that are expected to use the process in the T2 period. This is a challenge for all projects >£100m that are subject to LOTI, but the proposal is particularly problematic, given the reduced materiality threshold compared to SWW in England & Wales leading to smaller projects with different characteristics subject to the re-opener than was the case with SWW.

Using a generic onshore project requiring a DCO as an example, we highlight four main areas of concern in the diagram below, which shows the LOTI funding milestones (orange) alongside optimal (bottom blue row) and LOTI adjusted (top blue row), simplified project timelines. Delay risks are show in red in the middle as follows:

1) Risk of a **0 – 6 months** delay at the Eligibility to Apply (EtA) and Initial Needs Case (INC) stages due to the requirement to submit EtA no less than 6 months prior to INC and to submit INC no less than 12 months ahead of statutory consultation. The reduced cost threshold for LOTI means projects with much more varying characteristics will be captured. For many of these project types the process from strategic option to initial solution and then statutory consultation will be less than 18 months. In these cases, a delay of between 1 and 6 months is anticipated depending on the project. In other cases, a project may require only minimal consents and hence these milestones become redundant and would severely restrict project delivery.
2) Delay of between **3 – 6 months** whilst the Final Needs Case (FNC) assessment takes place because procurement activity cannot start prior to the output of FNC, which is confirmation of project need and the latest point where Ofgem can decide whether the project should be subject to competition.
3) Delay of at least a further **3 – 6 months** (dependent on the specific project) because procurement activities such as tender preparation and design cannot be paralleled with consenting activity as is often the case on an optimal programme, particularly where the project requires DCO. To maximise the efficiency of our project programmes it is often necessary to have some overlap between "construction" and "pre-construction" activities. The rigid nature of the proposed LOTI process, and the requirements to not prejudice any competition process, means networks would have to undertake this project optimisation at risk or not at all. If LOTI is implemented as currently proposed it is likely that networks will schedule activities in a way that directly aligns with the LOTI process causing overall project timescales to be extended.
4) Delay of a further **6 – 12 months** between getting final price information through a tender and awarding a contract as Ofgem undertakes the Project Assessment (PA) stage. This delay can be particularly acute for projects involving new cable circuits (onshore and offshore), where cable contracts are on the critical path and are ideally in place upon completion of FNC. This proposal is different from the T1 SWW approach which could facilitate this earlier contract award as observed on the Hinkley – Seabank project where contract award was made ~ 1 year ahead of the PA decision.

[redacted]

We estimate that a rigid application of the process as currently set out could lead to project delays of between 12 and 24 months. Two case studies have also been included at the end of our response to this question, using 1 historic and 1 current project to analyse the impact of the LOTI process. These real project examples show delays of between 15 and 24 months.

We note that Ofgem have stated that, in exceptional circumstances, we should propose timings as part of the eligibility assessment but that this would only be in rare cases. We believe Ofgem have underestimated the number of projects where this approach would not work. This is exacerbated by the reduced LOTI cost thresholds where many projects types will now be captured and must be efficiently progressed through LOTI without a negative effect on the achievable project delivery date.

We propose that flexibility of timescales is explicitly assumed for all projects to recognise their unique characteristics and that this is addressed in the Eligibility to Apply stage each time the LOTI process is used. Timing should therefore not be prescribed in the Licence, but they could form a useful part of the associated guidance documents as with current SWW guidance.

The LOTI guidance, referenced in the consultation document, must be published with enough time ahead of the RIIO-T2 period for review and consultation to ensure that we move forward with clarity of process. This is particularly important if compliance with the process is explicitly included in the drafting of the LOTI licence condition as networks may be unable to progress LOTI projects in fear of being in breach of compliance with guidance that has not yet been provided. This could result in further delays to project development.

(b) Total assessment time

In December of this year Ofgem will have made its Final Determination on the price controls of 9 separate electricity and gas network companies, including £25bn of TOTEX, only 12 months after having received their business plan submissions (18 months if the initial July 2019 submission is included).   In this context, we believe the proposed LOTI assessment timescales are disproportionate (30+ months in total – across EtA, INC, FNC and PA) for single projects that are generally no more than 4% of that level of TOTEX.

Ofgem is relying heavily on re-openers in the T2 period and it should challenge itself to undertake the appropriate scrutiny and assessment in a timescale that is closer to the 12 to 18 months of the whole price control, rather than the up to 30+ months it is proposing. This is particularly vital given the key role these major projects will play in achieving Net Zero in the quickest time and lowest cost to consumers.

(c) Interaction with other policy areas

The LOTI process also interacts with other policy areas such as competition, pre-construction funding and large project delivery. When considered together with the LOTI process, we believe that these related policy areas further exacerbate the risk of delay.

Other sections of our response to this question already cover the implications of the decision on competition being too late in the process.

The approach to pre-construction funding and the definition of what constitutes pre-construction activities will mean that delays are possible even if a more flexible approach is taken by default to LOTI milestones. Certain activities, such as early stages of procurement, acquisition of land rights and detailed surveys commensurate with requirements in construction are explicitly excluded from the definition of efficient expenditure required to obtain consents in Para 4.36 of the ET Annex. These activities will now no longer take place until after FNC, leading to delays of at least 3 – 6 months. We provide more detail in our response to ETQ11.

The approach to large project delivery, set out on p.25 of the ET Annex, introduces a suite of three LPD mechanisms intended to incentivise the timely delivery of projects >£100m. The design of any re-profiling, milestone-based approach and project delay charges needs careful design consideration so that they do not encourage network companies to overcompensate and take an overly risk-averse approach to project programmes in future. Ofgem seek a "low risk – low reward" price control and one of the few levers TOs have to adapt to this type of contract is to de-risk project programmes, with a likelihood of project delays as a result. Where these outcomes are undesirable for the consumer, we urge Ofgem to work with us to find alternative arrangements that provide the certainty needed to progress in an efficient manner.

(iv) Timing of competition decision

The Final Needs Case stage of LOTI is far too late in the project lifecycle for a decision to be made as to whether the project will be subject to late competition. This adds unnecessary uncertainty and, as noted in our views on the LOTI process above, will delay the delivery of projects to the detriment of consumers. A decision at this point in the process will erode the benefits of competition as the project will be significantly delayed to enact a competitive process increases.

We note that Ofgem sets out network company development requirements for late competition on p.110 of the Core Document, stating, "*Companies must ensure that they do not carry out any development work on eligible UM projects that is detrimental to the impact of late competition*". No further detail is provided on what type of development work would be considered to have a detrimental impact. Ofgem does not appear to consider the commensurate risk associated with this position.

Consenting large infrastructure projects is a very challenging task, which will be made more difficult if network companies are left with the uncertainty of whether or not a project may be subject to late competition and whether or not an activity they are undertaking to secure consents or maintain an efficient programme could be deemed detrimental to that competition. It is impossible to progress a project to consent without making certain assumptions around specific design elements. The less specific our proposals (i.e. to maximise the opportunity for design variances through competition) the harder, and more costly, it will likely be to achieve consent. Similarly, if proposals are very specific this could limit any subsequent competitive process.

Certainty of delivery model is required as early as possible to progress an effective and efficient development and consenting process. We urge Ofgem to commit to making the

final decision about competition at the Initial Needs Case stage at the latest to maximise consumer benefit of these projects and any competitive process.

(iv) Transition to LOTI for existing projects

We agree projects that have not received funding under SWW should transition to the new LOTI re-opener in the T2 period.

However, there are a number of projects that do not meet the current SWW threshold but would meet the updated LOTI threshold. In order to maintain the desired delivery dates for these projects, development must continue prior to T2 commencing. This may result in some projects passing key milestone stages (i.e. where INC would normally occur) prior to the T2 period. Clarity on how these projects can be accommodated to avoid un-necessary delays for customers and costs for consumers as a result of the SWW / LOTI transition is critical.

We would welcome formal guidance from Ofgem as to how projects should be treated where they do not meet the SWW criteria in RIIO-T1 but will meet the LOTI criteria in RIIO-T2.

5. Developments since the Draft Determination

A licence drafting workshop has taken place, but there have been no material developments in this policy area since Draft Determination.

6. Case studies – supplementary evidence

To support our views on the impact of the LOTI process on project timelines, we have developed case studies of 1 historic and 1 future projects >£100m (1 requiring DCO planning and 1 Town and Country / Marine Licence):

[redacted] Case study 1 [redacted]
[redacted] Case study 2 [redacted]

[redacted]

[redacted]

ETQ11. Do you agree with our proposed definition of PCF for RIIO-2, and the areas of work that we intend that definition to cover?

ETQ11 is answered within ETQ12 below.

ETQ12. Do you agree with our proposal to assess PCF costs as part of RIIO-2 Closeout, following the principles set out in Chapter 4?

We have considerable concerns over the areas of work PCF is intended to cover and the proposal to assess PCF costs as part of RIIO-2 Closeout. Our response to this question sets out: (1) context and T2 proposal, (3) the DD (4) our views on the DD and (4) developments since DD.

We note this area interacts heavily with ETQ10*. Do you agree with our proposed eligibility criteria for the LOTI re-opener and do you agree with the assessment stages, and their associated timings?.* We cross reference responses where relevant.

1. Context and T2 proposal

LOTI projects are on the critical path to enabling net-zero at minimum cost for consumers. Their need is triggered either by customer connections and/or the annual NOA process throughout the price control period, which is why the LOTI re-opener does not have a fixed submission window.

The preliminary works (including engineering development and consenting), described as pre-construction, of LOTI projects is currently funded separately from construction activities. An agile approach to funding efficient pre-construction work (including abortive work) is required in order to maintain the option of delivery dates and introducing competition into the process.

Pre-construction funding for SWW projects in the T1 period has been managed through a fixed, ex-ante pot of baseline allowances that could also be substituted to other projects as customer needs changed. This pot also covered abortive work. Our business plan proposed pre-construction funding for 4 projects >£100m with a NOA 'Proceed' signal.

In our experience the fixed pot approach used in T1 was not flexible enough to deal with the changing market and resulted in over £30m of pre-construction expenditure not covered by allowances. To address this, we proposed baseline pre-construction allowances for projects with a clear need case and developed an ex-ante volume driver approach as follows:

Allowance for all efficient activities to achieve consents: • 1.4 £m/km for new onshore projects • 0.3 £m/km for new offshore projects	• Extension of the Termination Provisions for Wider Works (TPWW) mechanism to recover allowances for efficiently incurred abortive works • No substitution between projects

In developing our ex-ante volume driver approach we looked at various cost drivers and approaches to designing a mechanism (fixed £ values per project, % of project cost, etc.). We found a £/km unit cost allowance that differentiated between onshore and offshore to be most robust.

2. Draft determination

Ofgem proposes the definition of pre-construction funding (PCF) as, "*the funding required to develop a LOTI project to the point that consents are obtained*". Activities explicitly deemed to form part of efficient expenditure to the point consents are obtained include:

- surveys, assessments and studies (those associated with developing the project itself, not those associated with further construction…)
- project design
- engineering development
- stakeholder engagement and consultation, including legal costs
- wayleaves, including legal costs
- planning applications, including legal costs

Baseline allowances aligned to projects that have a NOA proceed signal will not be substitutable between projects and projects that have not been included in the baseline would be funded through an ex-post cost assessment as part of RIIO-2 closeout. Alternative suggestions such as a bridging fund or within period adjustment for funding non-baseline projects are welcome.

As part of the ex-post assessment Ofgem have indicated that pre-construction funding above 2.5% of total anticipated project costs would only be provided in exceptional circumstances.

3. Our views on the draft determination

We set out our views below on (i) the PCF definition, (ii) PCF in baseline allowances, (iii) approach for PCF not baseline funded, and (iv) the 2.5% efficient cost benchmark.

(i) the PCF definition

The proposed definition of PCF as "*Pre-construction Funding is the funding required to develop a LOTI project to the point that consents are obtained*" is broadly sensible. It aligns to what has been applied in the T1 period and supports the introduction of competition in transmission better than other definitions considered. It may need to be tweaked somewhat to work effectively for projects that do not have an extensive consenting programme, such as cable/tunnelling projects, where the required pre-construction activities can look significantly different. We propose that pre-construction covers activities up to the end of our NDP 4.3 phase, which marks the end of engineering development, pre-construction surveys and any consent that may be required. This point marks the completion of engineering development and aligns with our internal sanctioning milestone, immediately before the project is tendered and contracts awarded.

The explicit list of activities considered to form part of "*efficient expenditure required to the point that consents are obtained"* are much more problematic and we seek additional clarity from Ofgem in this area. As currently drafted, the list precludes some activities that are efficient to commence prior to consents being achieved, are required to support the submission of a DCO application, essential in ensuring projects are not delayed and allowing for competition to take place on better information (both 'native competition' and CATO). These activities include, but are not limited to:

- securing land rights beyond wayleaves – e.g. easements and options to purchase, which can be a pre-requisite to applying for consents in some cases. It is important, particularly for DCO (which provides compulsory purchase powers) that we can demonstrate that we have pursued voluntary land rights before compulsory rights are granted.
- bundling of surveys – e.g. ground investigation works are necessary in some form for planning, but more intrusive works undertaken at the same time for construction design purposes often offers economies, early sight of conditions helps mitigate risk and allows for a more robust competitive tender
- early market engagement to inform design and preparation of tender packs for main works contracts

We anticipate that the Draft Determination list of efficient pre-construction activities would introduce a delay of at least 12 months into projects by delaying all procurement activities until after the Final Needs Case decision in the LOTI process. It could also increase project costs if detailed surveys are not undertaken before the project goes to tender. It also increases the risk that DCO applications are refused if we have not sufficiently explored options to obtain voluntary land rights. We have provided a further 2 confidential case studies, using real project examples, as part of our response to ETQ11 and ETQ12 to show how the delay manifests.

The scope of these activities seem to also be impacted by the statement in the Draft Determination Core Document (p.110), "*Companies must ensure that they do no carry out any development work on eligible UM projects that is detrimental to the application of late competition.*" Consumer benefits of timely project delivery are derived from an expansion of the efficient pre-construction activity list, but some of these activities have the potential to conflict with the direction on development work in the Core Document, stated above. A commitment to decide on whether a project is contestable or not at an earlier stage in the project timeline (e.g. the Initial Needs Case stage) would mitigate much of this conflict

We propose that the list of efficient pre-construction activities is either (i) expanded to include those listed above or (ii) decided on a case-by-case basis at the eligibility stage of LOTI, that Ofgem provide clarity on development work it would deem detrimental to the application of late competition and that a commitment is made to decide on whether a project is contestable by the Initial Needs Case stage at the latest.

(ii) PCF in baseline allowances

We welcome the decision to include baseline PCF for projects with a '*proceed'* signal in NOA 2019/20 and are supported by a clear engineering justification documentation. Ofgem have not allowed the pre-construction funding requested for projects in our business plan that did not receive a '*proceed*' signal in the NOA 2019/20, resulting in baseline allowances of £76m for pre-construction of two Eastern HVDC links.

Additional funding for new 'proceed' was not addressed in the Draft Determination, but Ofgem have indicated they are open to providing funding for all new '*proceed*' projects upon submission of the necessary evidence by network companies. We welcome this approach and have provided an updated annex to our business plan separately during the consultation period to address this requirement.

We note that there are customer driven projects with signed connection agreements, for example to connect east coast offshore wind (e.g. a new Norwich Main to Bramford 60km route), that are >£100m and not covered through NOA but that need pre-construction work to proceed imminently to maintain connection dates. It may be beneficial to include funding in the baseline for those projects with the strongest need case.

For financability reasons, **we recommend that PCF is treated as *fast-money*** when calculating allowances. This also aligns more closely with the accounting treatment of this expenditure, particularly if projects are not ultimately delivered by us.

(iii) Approach for PCF not baseline funded

We disagree that only projects receiving a '*proceed*' signal through NOA should be provided pre-construction funding. If this is the intention of the Draft Determination, we would welcome clarity on how pre-construction for other projects >£100m would be funded and what certainty would be required before Ofgem anticipate NGET should start to incur costs. For customer driven (non-NOA) projects, the signing of a connection agreement by a customer is normally a trigger for efficient pre-construction activities to commence because we are contractually obliged to progress their connection works at that point. The potential lack of a route to funding for these projects is likely to impact connection dates offered if not addressed.

As noted above, there are customer driven projects with signed connection agreements to connect east coast offshore wind that are >£100m and not covered by NOA that need pre-construction work to begin imminently to maintain connection dates. The amount of offshore wind facilitated by these projects account for over 25% of the government's 30GW by 2030 target. Our stakeholder engagement indicates that this target is likely to increase to 40GW, further strengthening the need for the pre-construction of these projects to be funded and in an agile manner to avoid delays.

PCF should be available to fund pre-construction for all projects >£100m, not only those driven by the NOA.

The Draft Determination proposes that companies spend efficiently to progress pre-construction on projects as required and that this would be assessed through an ex post cost assessment as part of RIIO-2 close out. The lack of certainty of funding this introduces during the price control will lead to delays in delivering projects as programmes are adjusted to mitigate risk. Given the number of projects that are anticipated to start development to support the 2030 targets and ultimately net-zero by 2050, this uncertainty is particularly concerning.

The Draft Determination helpfully acknowledges that efficient costs should be recoverable, regardless of whether the requirement subsequently changes and the importance of TOs being able to progress projects in a timely manner. It explicitly indicates an openness to alternative solutions, and we would urge further consideration of a few options and welcome the opportunity to further develop these with Ofgem and other stakeholders:

i. Our proposal for **separate automatic unit cost allowances** for the pre-construction of onshore and offshore projects as part of our business plan submission would provide the agile approach to adjusting the funding required to ensure new projects are not unnecessarily delayed, baseline funding not used is automatically returned to consumers and have the added benefit of providing a strong incentive to minimise costs.

   In our development work on this mechanism we found route kilometres to be a reasonably robust cost driver and proposed £/km ex-ante allowances for offshore and onshore (see example plot for onshore projects from our business plan submission, below). Efficient expenditure on abortive work would be covered through a separate claim, like the existing TPWW mechanism. Whilst this proposal has not been acknowledged in the Draft Determination, we still believe it has the potential to deliver most consumer benefit compared to other options and is better than the spend at risk and ex-post true up approach.

[redacted]

NOTE: Bramford-Twinstead and Horizon projects did not progress all the way to achieving consents

ii. A further option is to use the proposed **LOTI re-opener process**, being put in place to provide construction funding, to adjust pre-construction allowances. The LOTI process could be used to assess pre-construction funding requirements and provide allowances for the project in question where it is not included in baseline PCF allowances (e.g. at the Eligibility and/or Initial Needs Case stages) and, where necessary, could also be used to adjust PCF allowances at the Final Needs Case stage. Our initial analysis indicates it is likely that we will have spent in the order of 50% of total pre-construction expenditure by the Initial Needs Case decision (likely to be higher for offshore projects). An approach that provides 50% funding at Eligibility stage, followed by the remaining funding requirement at Initial Needs Case stage could therefore provide the necessary certainty of allowances to progress. This approach could also be combined with an agreed £/km unit cost allowance so that the first 50% of PCF funding can be made automatic.

A separate claims process may still be required for efficient abortive work. This approach would not be as agile as an automatic unit cost allowance but is better than the spend at risk and ex-post true up approach.

iii. If options (i) or (ii) are unacceptable, the ability to **substitute baseline allowances between projects** may provide additional flexibility and could go some way towards minimising delays when requirements inevitably evolve through the T2 period. This could also automatically cover efficient abortive costs and improvements could be made on the T1 approach to better track the evolution of allowances and outputs over the period. Whilst this approach is far from ideal, likely still requiring TOs to spend at risk and therefore delay projects, it is better than the spend at risk and ex-post true up approach for all uncertain projects.

We would welcome the opportunity to work with Ofgem and other stakeholders to develop a more agile approach to adjusting allowances for the pre-construction of projects >£100m so that delays are avoided and TOs are appropriately incentivised, while retaining sufficient flexibility to facilitate competition.

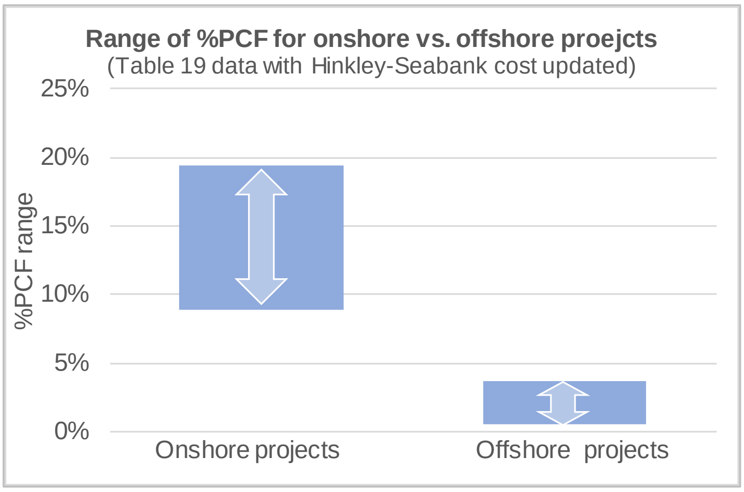
2.5% efficient cost benchmark

We agree that pre-construction funding requests need to be well justified as part of any cost assessment process. Our understanding is that the Draft Determination provides the 2.5% of total project cost efficient benchmark to help guide TOs and provide some comfort in the context of a spend at risk and ex-post true up approach. As set out above, other more effective mechanisms are available to adjust pre-construction allowances through the price control period that do not require such a guide.

Not only is the efficient cost benchmark not required, it is fundamentally flawed both as a concept and in how it has been calculated. As indicated in our response to the LOTI process in ETQ10, projects >£100m are unique in their characteristics and defining a single efficient % rate which is robust across all project types is not possible. In the first instance, the pre-consent activities required for onshore and offshore projects are significantly different. For example, onshore projects >£100m will normally involve new overhead line routes, which must go through the Development Consent Order process in England and Wales. Offshore projects, on the other hand, do not generally involve new overhead line routes and instead go down the Town and Country planning/marine licencing route. Onshore projects require ground surveys, whilst offshore projects require marine surveys in the pre-construction period. The differences between DCO and Town and Country planning and between ground and marine surveys lead to completely different costs.

In addition to being fundamentally flawed conceptually, the calculation in Table 19 of the ET Annex is also flawed. We have assumed that the column entitled, "Construction cost total (£m)", should actually read "Project cost total (£m)" to align with para 4.42 and the right most column in Table 19. The following errors are evident:

- Input data used is incorrect; for example, [redacted] This increases the PCF% of total project cost to 8.9%
- The PCF £m used across the various historic projects does not compare them on a like for like basis because the accepted definition of pre-construction has evolved over time. For example, NGET's costs incurred up to gaining consents on the Western HVDC link project are much higher than the £10m, even though this is the captured 'pre-construction' cost in the licence.
- A clear difference exists between onshore and offshore projects (due in part to the differences highlighted above) that have not been considered. This is evident when comparing the PCF% in Table 19 for the 2 project types (with Hinkley-Seabank costs having been updated), as shown in the chart, below. Far from costs only exceeding the 2.5% threshold "in exceptional circumstances", as intimated in para.4.42, this would be normal for onshore projects.



- A weighted average has been used, which is incorrect for this purpose, and serves to skew the % towards more expensive offshore projects that are cheaper to consent.

The graph below plots PCF (£m) and Total project cost (£m) from Ofgem’s Table 19 (both with and without Hinkley-Seabank costs updated). It shows that there is no robust relationship between the two variables used in the Draft Determination to arrive at the 2.5% efficient cost benchmark.

[redacted]

The 2.5% efficient cost benchmark is not required if a much needed, more agile approach to adjusting allowances over the period is adopted. It is flawed in both concept and execution and should be scrapped.

5. Developments since the Draft Determination

A licence drafting workshop has taken place, as well as a cross-TO working group but there have been no material developments in this policy area since Draft Determination.

6. Case studies – supplementary evidence

To support our views on the impact of the PCF Definition on project timelines, we have developed case studies of 1 historic and 1 future projects >£100m (1 requiring DCO planning and 1 Town and Country / Marine Licence):

[redacted] Case study 1 - [redacted]
[redacted] Case study 2 – [redacted]

[redacted]

[redacted]

ETQ13A Do you agree with our proposed scope of, associated eligibility criteria for, and timing of the submission window under the MSIP re-opener?

PLEASE NOTE: the DD did not have any questions on Ofgem's proposals for the generation and demand volume driver and the shunt reactor volume driver mechanisms. We have provided our views on these proposals as ETQ13B and ETQ13C respectively.

The use of a common MSIP re-opener mechanism is appealing conceptually. However, when considering the approach that is most likely to deliver a reliable, sustainable and affordable electricity transmission system in practice, it is difficult to apply a common approach across so many different aspects of company business plans. Other than all being anticipated to cost <£100m, the characteristics of each category of investment is very different; not least the drivers for each and the consumer value they deliver.

The proposal to undertake an ex-post true-up of allowances across projects funded through MSIP at RIIO-2 Closeout (para.4.58) is inconsistent with the core principles of the RIIO approach to regulation and represents an asymmetric risk for companies that is not commensurate with the *low risk / low return* price control Ofgem have set out to achieve. The uncertainty of allowances removes the drive for efficiency and all incentives to innovate in solution or delivery on hundreds of millions of pounds of expenditure. One of the few levers that companies have to mitigate this is through re-profiling project programmes, with a likelihood of project delays as a result.

The CMA, in para 6.217 of its final determination of the case of SONI Limited vs. Northern Ireland Authority for Utility Regulation confirms the risk of ex-post assessments from the company perspective, "….*Any regulatory framework that involves an ex-post evaluation of costs may have similar asymmetric risk properties: the most a company can recover is its actual expenditure, but it faces a risk that some of its expenditure may be considered inefficient and it may not recover this portion of its expenditure*".

Ofgem should abandon ex-post true ups in favour setting ex-ante allowances that maintain incentives on companies to reduce costs.

We have concerns on scope, eligibility and timing across all three areas of the Draft Determination, (i) outlier generation and demand connection projects, (ii) projects that increase boundary capability and (iii) externally driven works.

(i) outlier generation and demand connection projects

In order to meet the net-zero carbon emission target, we estimate we may have to connect up to 30GW of total generation in the T2 period of which up to 11GW is renewables with the remainder comprising of interconnectors, storage, and non-renewable generation required to support the transition (e.g. electrification of transport). Therefore, a robust and agile funding mechanism is a key enabler in achieving the net-zero carbon emission target.

The design of a robust, cost-reflective ex-ante unit cost allowance (UCA) is key to ensuring that TOs have the funding certainty to progress at the pace required and incentives to innovate and minimise the cost of meeting customer needs. We have serious concerns about the combined generation and demand mechanism proposed in the Draft Determination and urge Ofgem work with to ensure we are not unfunded for whole categories of connection and customer types. As there is no question for generation and demand unit cost allowances we have provided our views separately in a 'Part B' of this question.

We would welcome the opportunity to work with Ofgem in establishing a more robust ex-ante UCA for generation connections and demand connections (see ETQ13B).

The Draft Determination proposes an MSIP threshold for generation and demand connection outliers of between £25m - £100m and where forecast costs are at least double the level provided for in the relevant volume driver. From Para. 4.20, we understand that this threshold may have been conceptually linked to a similar treatment of input data used to calculate UCAs, but this direct relationship does not exist in reality.

Para.4.56 states that, *"we consider the £25m minimum threshold to be a proportionate response to the likely scale of the works in question and an appropriate approach to the sharing of commercial risk to which the TO is exposed under totex regulation."*

The threshold does not represent an appropriate approach as companies are exposed to an asymmetric risk because of poor UCA design (e.g. the £8/kW/kVA proposed for NGET is fundamentally flawed and massively underfunds most projects) and because they have been directed to submit baseline plans that are lower than their P50 view of investment needs (ref. Para.3.4 of the RIIO-2 Business Plan Guidance, "*The business plans must: • design their baseline revenues around parameters which are no greater than the lowest point of the ranges provided in the ENA Scenario Working Group report*"). Alongside a £25m threshold there is a high likelihood of a funding gap.

The MSIP threshold should therefore be designed to ensure companies are efficiently funded to deliver for their customers and against their licence obligations, irrespective of the input data used in the UCA calculation.

The proposed approach could result in material gaps in funding up to a maximum of £49m per project (i.e. £99m x 49%) and introduces perverse incentives for projects just under the threshold to increase costs in order to access funding. For example, a [redacted] CCGT connection requiring £23m of efficient investment would only attract £12m of allowances. However, should the TO incur £2.1m of additional spend, to bring it into scope of the MSIP reopener, it would receive additional funding, even if the £2.1m of inefficient spend was disallowed; i.e. £23m (a £2.1m deficit) vs £12m (an £11m deficit).

To avoid the potential for significant funding gaps, perverse incentives to increase costs in order to access funding and potential delays to connection projects as a result of a lack of certainty of allowances, the threshold should be lowered considerably. We also believe that consumers should be awarded the same level of protection as companies, requiring that the threshold is symmetrical. An approach that allows adjustments to funding whenever the UCA funds >125% or <75% of costs would lower the maximum exposure on a single project to £24m (i.e. £99m x 24%). A robust UCA design should give confidence that the number of outlier projects will be minimal and therefore the number needing to access funding through the reopener manageable and proportionate.

Ofgem should remove the >£25m criteria and set a symmetrical threshold at a level where the UCA funds greater than 125% or less than 75% of costs.

The Draft Determination proposal of a single re-opener window in January 2024 is problematic for generation and demand connections, where the need for investment is triggered through the ESO in response to a customer connection application. The volume of applications tends to be high and spread across the year and around key milestones such as Capacity and CfD auctions. Getting connected to the network is generally on the critical path for these projects given the relatively longer lead times for transmission work. This is the rationale for an automatic, ex-ante UCA.

Restricting applications for funding to connect outlier projects to a single window in 2024 is likely to delay some connections as the re-opener process is factored into programmes. Given Ofgem's extensive reliance on re-openers in the T2 period a single reopener window would also be likely to create a bottleneck of workload for Ofgem and industry alike as all applications are funnelled into a single period. Spreading these out over the T2 period is more aligned with the natural trigger for these types of project and is likely to more efficiently spread workload across the period.

Ofgem should shift from a single re-opener window in 2024 to an annual process that would reduce project delays and more efficiently spread industry workload.

(ii) projects that increase boundary capability

Boundary capability reinforcements provide network capacity between different areas of the transmission system, enabling the connection of low-carbon energy sources and minimising the cost of transporting power from where it is produced to where it is consumed. Investments are triggered through the annual NOA process, run by the ESO. A single reinforcement can save consumers 10’s to 100’s of millions of pounds per annum in system operation costs compared to not investing.

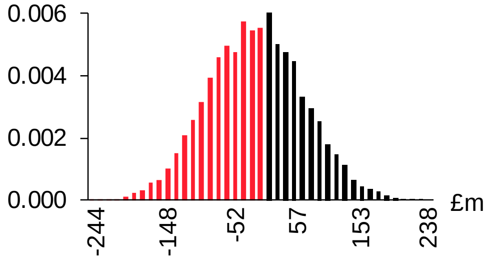
The Draft Determination approach to dealing with uncertainty in boundary capability reinforcements in the T2 period is overly focussed on ensuring that allowances match costs as closely as possible whilst putting at risk consumer benefits that are relatively much more valuable. It does so unnecessarily as it has not fully considered the information we have provided to support a more agile, ex-ante approach or considered how this might be improved to further optimise consumer benefits.

The proposal in the Draft Determination is detrimental to consumers because (i) it completely undermines all incentives to innovate – increasing TO network costs, (ii) introduces delays in setting allowances and leaves funding gaps that will delay projects – increasing ESO operating costs (i.e. constraint costs) and delaying customer connections and (iii) disproportionately increases administrative burden through a poorly designed and cumbersome reopener process that increases overall costs. We believe an automatic ex-ante approach can be designed in a manner that provides enough confidence in its cost-allowance performance so that the aforementioned consumer benefits can be maintained and provide more details in our response to NGETQ17.

Para.4.52 sets out Ofgem’s consideration of the concerns of using a re-opener and ex-post true up approach. Here, the Draft Determination considers it acceptable that the innovation and efficiency incentive is reduced because it deems that this is balanced by the benefit of better protecting consumers from overpaying for outputs and avoiding undue windfall gains and losses for network companies. Ofgem have not provided any details of their assessment of this balance, which we believe is flawed. Firstly, an ex-post true-up approach does not reduce, but completely removes, the drive for efficiency and incentive to innovate. This aspect has been underestimated in Ofgem’s assessment. Secondly, the benefit of protecting consumers and companies form windfall gains and losses is minimal for a well-designed automatic, ex-ante unit cost allowance approach and can be reduced further through the application of additional protective measures. This aspect has been overestimated in Ofgem’s assessment.

Our response to NGETQ17 sets out the robust design framework we put in place and followed to design our proposal. Testing of the resilience of our UCA using Monte Carlo analysis (submitted alongside our business plan) resulted in a standard deviation of allowances vs. costs of £68m, as shown below. This is compared to our baseline submission of £507m.

Allowance-cost performance of NGET UCA proposal for T2 boundary capability scenarios



Mean: -£4.37m; St.dev: £68.27m
10,000 scenarios

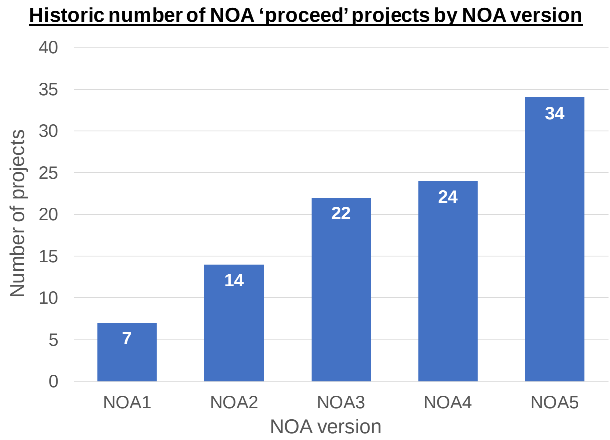
Consumers are exposed to just over 60% of any deviation of allowances from costs through the totex incentive mechanism (i.e. £68m x 60% = £41m), further limiting the impact. Application of our proposed UCA to real-world changes in projects such as the latest NOA update and back-testing against RIIO-T1 projects shows even better allowance vs. cost performance – as set out in our response to NGETQ17.

Additionally, we are working with Ofgem to consider the application of a cap and collar approach for allowances relative to costs on the portfolio of work delivered in T2. This would further increase confidence by adding protections around the operation of the automatic, ex-ante approach that limit how far allowances can deviate from costs across the whole price control. Such a limit could be set with reference to the Monte Carlo analysis outcomes used to test performance of the model. For example, deviation of allowances from cost could be limited to a percentage derived from 2 standard deviations relative to baseline proposals. Using numbers from our Monte Carlo distribution (shown above) and submission this would be (£68m x 2) / £507m = 26%.

Para.4.52 also indicates that all projects that have a developed need case with mature plans are proposed to be provided baseline funding and there is no evidence of a delay that would be caused by the re-opener mechanism.

Whilst we have submitted evidence to support inclusion of all NOA5 'proceed' projects into baseline funding and Ofgem have been positive about their intention to provide funding, this is not included in the Draft Determination and is currently still under consideration. Even if funding is provided, there is a consistent track record of year on year churn in projects recommended by NOA due to changing underlying system requirements and new solutions becoming available.

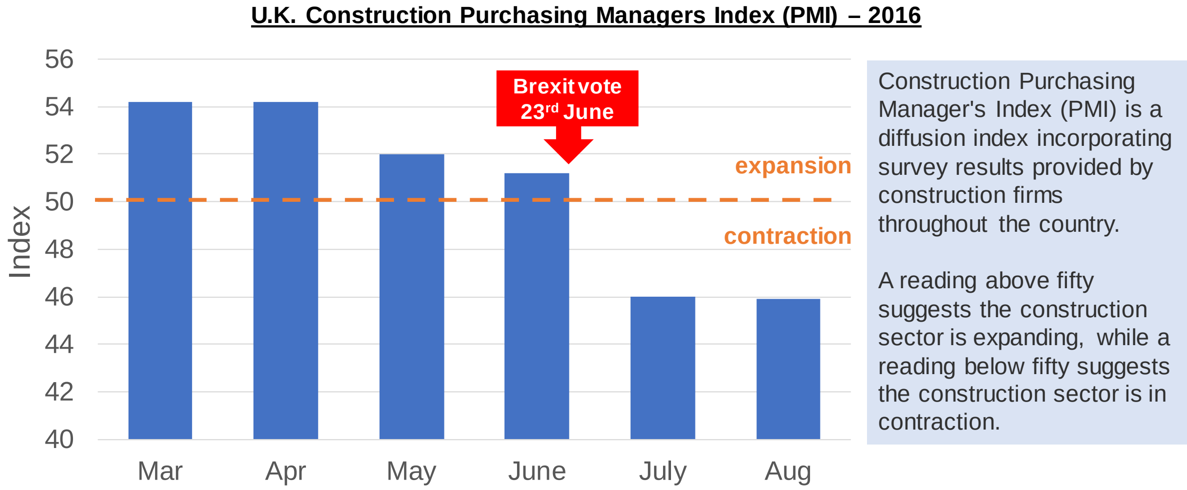
The number of NOA projects given a 'proceed' recommendation changes year on year, as shown below. Over the last 3 years (i.e. the same time as from the NOA published in January 2021 to the opening of the re-opener window in January 2024) the net change in NOA proceed projects has been 12 projects. This does not take account of underlying gross project churn which would further increase this number. As the January 2021 NOA will be the first to account for FES scenarios that are net-zero compliant, we see no reason for the historic trend to change. We therefore conclude that baseline funding on the latest NOA is not evidence of, "*covering most if not all investments required to proceed before the reopener window*".



The risk of delay to boundary capability projects is evident from both the high-level business perspective of making investment decisions in the face of uncertainty and from the perspective of specific project timelines relative to the time between the next NOA publication and the reopener window.

From the high-level business perspective

Businesses faced with high levels of uncertainty delay investments. One way to illustrate this is to consider the UK Construction Purchasing Managers index around the time of the Brexit vote. The uncertainty introduced by the result of the vote on the 23rd of June caused managers making investment decisions to delay these decisions, taking the construction sector swiftly into overall contraction in the month of July.



This effect is amplified for regulated networks operating in a low risk and low return environment when faced with uncertainty over future revenues as a result of both the timing of reopeners and the application of ex-post true ups. The biggest lever available to mitigate risk is to minimise material investment decisions made before greater certainty of allowances is available. This will inevitably lead to project delays.

From the specific project timeline perspective

A new project given a proceed signal in 2021 would have to wait for funding certainty until an MSIP decision is made towards the end of 2024 in the Draft Determination proposals. Whilst the Draft

Determination does not indicate the timing of MSIP reopener decisions, this period is likely to be at least 3 ½ years (we have assumed the January 2024 window is extended to account for NOA publication in the same month). In contrast, the short lead time of some solutions, such as SmartWires, can deliver consumer benefits within 1 ½ years of receiving a NOA proceed signal – less than half the period of uncertainty in allowances. With network companies reluctant to commit consumer money in advance of some certainty of allowances a delay of 1 to 3 years would be highly likely in this example. The opportunity cost for consumers of missed constraint cost benefits over this period is many multiples of the cost of the project and likely multiples of the risk of allowance vs. cost mismatch of an automatic, ex-ante UCA that would remove delay risk altogether.

We welcome the opportunity to work with Ofgem to further develop an automatic, ex-ante UCA mechanism, avoiding the need for ex-post true ups that undermine the drive for efficiency and incentives to innovate and, alongside re-openers, introduce uncertainty of allowances restricting the delivery of innovative solutions at pace.

The Draft Determination proposes a minimum threshold of £25m for the Medium Size Investment Project re-opener for boundary capability projects that have a NOA 'proceed' signal. Our baseline plan for the T2 period contains 21 projects in total, with 17 that are <£25m. Therefore, <u>over 80% of boundary capability investments planned in the T2 period would not be funded if they had to go through the Draft Determination proposal for dealing with uncertainty.</u>

Projects such as hotwiring can cost as little as [redacted], whilst some mechanically switched capacitor solutions can be delivered for around [redacted] and SmartWires tend to come in around [redacted] cost (although all these costs vary depending on the application / installation). The cost of these projects is not directly related to the consumer benefits that they deliver, which will be many multiples of cost in almost all cases.

The proposed threshold, based on projects costing >£25m, is flawed because it will leave a material funding gap for network companies, introduces a perverse incentive to increase project costs below the threshold to access funding and, most importantly, does not consider the consumer value projects deliver which is invariably much higher than cost.

Ofgem should abolish the concept of a threshold for boundary capability projects.

Each year when the NOA makes its recommendations there is churn in the projects that are indicated to proceed as both network requirements and solution options available change (e.g. the number of proceed projects has increased from 14 to 34 over the last 4 NOA iterations). This churn is valuable for consumers as it ensures the optimal solution is delivered once the need is clear. The Draft Determination proposal of a single re-opener window in January 2024 is not commensurate with the change that will result from the annual cadence of the NOA process.

An automatic ex-ante UCA approach provides certainty of allowances from the start of the price control and would therefore resolve this issue. At a minimum, if Ofgem forego the consumer benefits of innovation and stick with the proposed re-opener approach for the T2 period, an annual re-opener window is required to align with the NOA. If Ofgem adopt an annual re-opener, this could still lead to more limited project delays to accommodate the submission, cost assessment and decision process when compared to some of the short lead time solutions and particularly given the volume of assessments that will be required each year (as shown in the historic trend above).

Additionally, it is difficult to see how an annual re-opener approach can be made agile enough (likely needing to forego cost-assessment) and not require ex-post assessments, therefore undermining any drive to find efficiencies and innovation (see i. above). For this reason, an ex-ante UCA approach is the only way to avoid delays and the associated consequences for consumers).

Even if Ofgem move to an annual re-opener approach to align with NOA, it would not be possible to avoid ex-post assessments that undermine efficiency and innovation. We believe an ex-ante approach is the only way to avoid delays and associated consumer

(iii) externally driven works

The Draft Determination proposes a single reopener approach to bring together several bespoke outputs submitted by TOs, typically related to areas where system needs may change due to external events. A single reopener is proposed to avoid the disproportionate regulatory burden of numerous, individual reopeners.

A specific list of areas eligible for assessment through the MSIP reopener are listed and associated conditions that need to be satisfied for a funding request to be assessed are provided. The 1% of average annual baseline revenue, common reopener, threshold applies; as does the January 2024 window.

We agree with the approach of a single reopener but believe that the thresholds and windows should be tailored to the specific area. In most cases an annual reopener would allow investments to proceed without delay and better distribute Ofgem and industry resource across the T2 period. Two additional externally driven areas relating to security of supply should be included in the list (one which is indicated as being eligible in the NGET Annex). We cover each area listed in the Draft Determination as eligible in-turn, below, followed by the additional areas that should be covered.

We agree with Ofgem proposal to introduce forecasting for outputs and allowances, but this should be extended to include re-opener allowances as details in our response to FQ12, FQ34 and FQ35.

We propose that an annual reopener window should be the default for all MSIP categories and consideration should be given to unique windows and thresholds for individual externally driven areas based on specific circumstances.

Flooding (Extreme Weather)

We have been given partial funding for Extreme Weather and will need further funding to meet the current requirements of ETR138. This re-opener should be extended to cover current and future requirements of ETR138 and climate change.

Threshold – There needs to be confirmation of regulatory allowances ahead of spend. This is particularly important because the challenging RIIO-2 finance framework proposed by Ofgem contains no contingency for networks to spend at risk or absorb small spends therefore, we do not support there being a materiality threshold applied to this category or any other resilience categories. The trigger for a requirement to invest in this area stems from government mandated requirements to protect consumers and Ofgem should recognise this in the speed of its adjustment to regulatory allowances. The value is also unlikely to trigger the materiality threshold. As such we propose the approach to materiality should be consistent with that for Cyber Resilience where no materiality threshold is applied.

Window – The re-opener window timing is too late in the price control period for this category. We propose that it should be able to be triggered either ad-hoc when conditions are met or through an approach to the MSIP window that extends it into an annual process.

Scope / conditions – We agree that requests would be considered following updated ENA ETR138 guidance on flooding and/or direction from BEIS to protect sites from flooding. We also propose that the scope of this areas is extended to include all funding that may be required for extreme weather to meet the current requirements of ETR138.

As the "Ensuring a resilient electricity network" re-opener we proposed was rejected, we propose that the flooding category of the MSIP re-opener should be widened to cover potential extreme weather investment required to adapt to the consequences of climate change.

UK leadership depends on building resilience to climate change, a resilience which no UK sector has yet demonstrated for even a 2°C rise in global temperature. This is a moment to improve the effectiveness of national planning for the threats from climate change that are already inevitable, as well as the uncharted but potentially catastrophic change if higher levels of warming occur." (Reducing UK emissions Progress Report to Parliament June 2020)

The CCC have identified adaptation as a priority action, planning for a minimum 2°C and consideration of a 4°C global temperature rise (by 2100 from pre-industrial levels). Despite temporary reduction in emissions from the COVID crisis, global greenhouse gas emissions are still on a pathway for 3°C or more of warming by 2100.

The ENA is actively working to secure the resilience of the energy network and has created the industry wide Adaptation to Climate Change Working Group to understand adaptation vulnerabilities in the next round of adaptation reporting.

There is a risk that we will fail to deliver resilient assets to mitigate the impacts of climate change, due to a lack of understanding, knowledge and subsequent action. Consequently, we are actively seeking to understand how the nature, likelihood and intensity of hazards will change in line with the most up to date climate model (UKCP18 was released in 2019) and so assess the vulnerability of our network and the impacts and identify possible adaptation options. This will consider how multi-hazards (e.g. a combination of drought, high rainfall and high temperatures) will lead to physical impacts on our network. The result of this work is due in quarter one 2021 and we will need to act on the findings. As this is in progress, we can't yet say what the financial impact would be, only that it would be prudent to include a reopener in T2 should the models suggest we need to take immediate action (within T2) to ensure no adverse effects on our customers and maintain security of supply. The consequence would be a failure to secure suitable funding and investment to continue to deliver electricity supply services to end consumers in future climate change scenarios.

Black Start

Threshold – There needs to be confirmation of regulatory allowances ahead of spend. This is particularly important because the challenging RIIO-2 finance framework proposed by Ofgem contains no contingency for networks to spend at risk or absorb small spends therefore, we do not support there being a materiality threshold applied to this category or any other resilience categories. The trigger for a requirement to invest in this area stems from government mandated requirements to protect consumers and Ofgem should recognise this in the speed of its adjustment to regulatory allowances. The value is unlikely to trigger the materiality threshold and therefore we do not think a materiality threshold should be applied to this category.

Window – We propose that this area should be able to be triggered either ad-hoc when conditions are met or through an approach to the MSIP window that extends it into an annual process.

Scope / conditions – We agree with the condition that requests will be considered following the new Black Start Standard, currently under review by BEIS.

ESO driven requirements

Threshold – Many of the investments that benefit the ESO will not meet the common reopener threshold but can provide consumer benefits many times this level. We propose no threshold is put in place for this category. A lack of consideration of consumer benefits is a common problem when setting thresholds on the basis of project cost.

Window – The dynamic nature of ESO requirements and relatively short-lead times of most solutions to these requirements, do not lend themselves to a single reopener window. We propose either an annual window or an ad-hoc approach designed into the new process Ofgem propose to develop with the ESO and TOs. We welcome the opportunity to develop such a process.

Scope / conditions – We agree that a formal request by the ESO for additional investment in relation to system operability and constraint management requirements is the condition for this area. The 'formal written request' should be designed carefully so that it is proportionate and does not delay investment that benefits consumers. We would welcome the opportunity to work with Ofgem, the other TOs and the ESO in the development of an additional process, similar to NOA, for the ESO to request works where there is a clear CBA supporting intervention.

Projects to maintain SQSS compliance

Threshold – We agree with the application of the common reopener threshold.

Window – We agree that a single reopener window in January 2024 works for this area.

Scope / conditions – We agree with the condition of the TOs demonstrating the need to modify the network against the SQSS.

Harmonic Filtering

Threshold – We agree with the application of the common reopener threshold.

Window – We agree that a single reopener window in January 2024 works for this area, but an approach to the MSIP window that extends it into an annual process is better.

Scope / conditions – We agree with the condition of requests from customers to aggregate and deliver harmonic filtering requirements, or ESO/TO system studies showing a potential breach of planning limits.

Energy Data Taskforce recommendations

Threshold – The trigger for a requirement to invest in this area stems from government mandated requirements and we do not think a materiality threshold should be applied to this category.

Window – The re-opener window timing is too late in the price control period for this category and it should be able to be triggered either ad-hoc when conditions are met or through an approach to the MSIP window that extends it into an annual process.

Scope / conditions – We agree with the condition of Energy Data Taskforce recommendations regarding specific outputs required to meet principles developed via industry working groups.

Tyne Crossing

Threshold – The trigger for a requirement to invest in this area has already been reached, driven by a legal requirement for NGET to remove the Tyne Crossing when requested by the Port of Tyne, and the subsequent high constraint costs imposed on consumers when this occurs. A materiality threshold therefore should not be applied to this project.

Window – The trigger for investment on the Tyne Crossing has already occurred, with further delays incurring additional constraint costs throughout T2 as wind farm jacket production is ramped up to assist with NetZero. Ofgem have incorrectly stated in draft determination that NGET and Ofgem have mutually agreed to remove this project from the baseline. NGET have consistently stated that the timing of the investment and impact on constraint costs requires this project to be funded in, or before T2 through baseline allowances.

Scope / conditions – We agree with the condition of the TOs demonstrating the need to modify the network against the SQSS.

ADDITIONAL AREA – Protection and Control Upgrades (indicated as eligible in NGET Annex of DD)

As electricity systems decarbonise they have to contend with the operability implications of increasing volumes of renewable generation connected to the network via power electronics. This results in declining and more volatile short-circuit levels, which is a major risk to the safe and reliable operation of existing transmission protection equipment that has not been designed to operate across such a range of conditions. As more and more renewables connect to the system the issue becomes worse, but no single generator triggers a need to make an investment.

To deal with this we requested baseline funding for (i) detailed modelling and coordination studies and (ii) relay settings review and setting changes. We also proposed that, upon the outcome of our modelling and coordination studies, a reopener should be used to assess and allocate appropriate funding to allow the necessary protection upgrades to go ahead.

The Draft Determination (NGET Annex p.78) provides baseline funding for the detailed modelling and coordination studies and Table 17 – Additional LRE schemes in the NGET Annex (p.48) also indicates that, "*When the study works are complete we propose to consider funding via the Medium Sized Investment Projects Uncertainty Mechanism rather than the separate mechanism NGET proposed*"

We propose that the potential requirement for protection upgrades is eligible for funding through MSIP and is listed in para.4.57 of the ET annex, that it is triggered by the outcome of studies that have been provided baseline funding and that applications can either be made in the single January 2024 window or through an annual window.

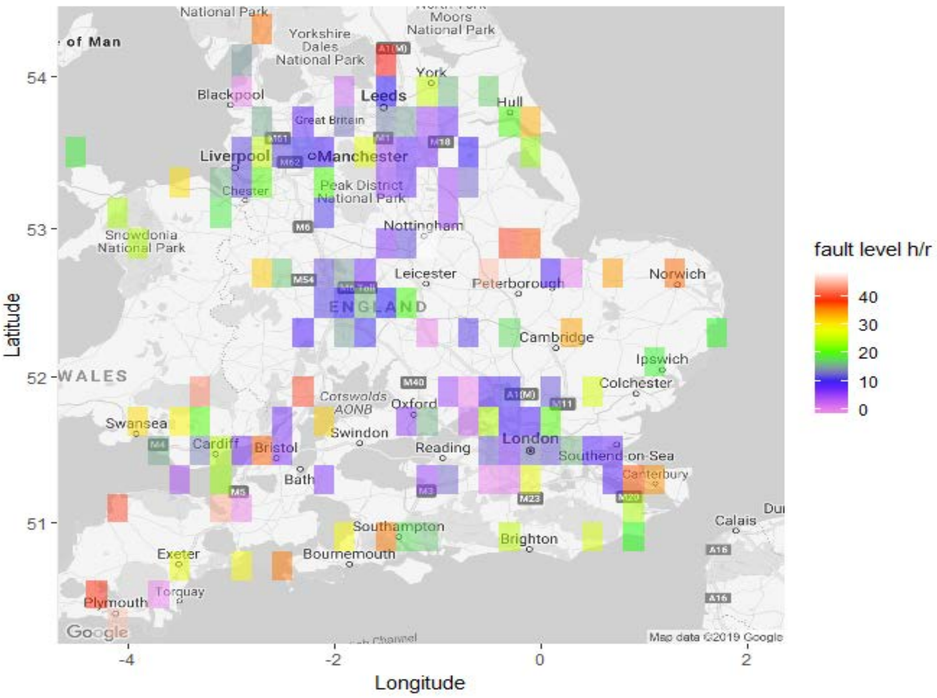
ADDITIONAL AREA – LV Rebuild / Embedded Generation

Access to the MSIP reopener is required to fund upgrades to switchgear at Grid Supply Points in order to accommodate embedded generation connections in the DNO network, where this is shown to be the best whole system solution. This work is triggered by the DNO through the Statement of Works process as set out in Section 6.5.5 of the Connection and Use of System Code.

Increasing volumes of distributed generation leads to increases in fault-levels at the Grid Supply Point. Fault levels exceeding the rating of substation assets presents a physical safety risk as well as a risk to security of supply. Our analysis for the T2 period showed that we could have to spend more than £199m on upgrading over 16 low voltage sites because of worsening fault level issues.

This is especially a problem for low voltage Grid Supply Points, which are immediately affected by increased power flows resulting from DNOs connecting more embedded generation. At high voltage sites, the impedance of the transformers mitigates the effects of rising fault levels.

The figure below illustrates the operating conditions of 132kV sites owned by National Grid that directly supply DNO areas with significant volumes of embedded generation. At this voltage level, it can be seen fault level headroom is generally low across the country and nearly depleted at some GSPs. We currently have 16 Grid Supply Points in England & Wales where fault level headroom is almost zero.



We proposed a volume driver to fund this work in the T2 period, which was rejected in the Draft Determination (NGET Annex p.78) on the basis that we had not demonstrated that expenditure is clearly beyond BAU.

We are surprised by the Draft Determination because this is an area that is clearly required to facilitate customer connection activity in the distribution network, has strong stakeholder support as evidenced in the engagement logs accompanying our business plan submission, is triggered through a codified industry process, was funded in the T1 period and where we have explicitly not requested baseline funding to allow for whole system alternatives to be explored before upgrading switchgear on our network.

Without a route to funding for this work, the transmission network will become a blocker to the connection of embedded generation in many areas.

It is essential that transmission work to accommodate distributed generation connections is eligible for funding through MSIP, that it is triggered by a DNO request and that applications can either be made when required or through an annual window.

ET13B Generation and Demand volume driver (MSIP reopener for outliers)
Context and T2 proposal

Customers have told us that they want us to make it easy for them to connect to the network. The agility of an automatic ex-ante uncertainty mechanism based on unit cost allowances (i.e. a volume driver) allows us to deliver our licence obligations in a timely way for customers and ensures that risks are allocated to the party best able to manage them.

In the context of a baseline plan built on the lower end of the ranges in the Common Energy Scenario, as stipulated in Ofgem's business plan guidance, an effective uncertainty mechanism is key to connecting other transmission service providers seeking to connect in response to ESO pathfinders and the additional volumes of low carbon generation and the demand required for the electrification of transport and heat to facilitate net-zero. For example, we estimate that we may need to connect up to 30GW of generation, interconnector and storage projects in the T2 period to remain on a path to net-zero by 2050, whilst our baseline plan connects just over 15GW.

To ensure an equitable balance of risk between consumers and network companies, it is important that the unit cost allowances (UCAs) are as reflective of anticipated costs as possible. This will be more difficult to achieve due to the low baseline plan that was required to comply with business plan guidance and consequential effect of UCAs operating predominately in one direction over the T2 period.

Volume drivers are used to deal with uncertainty for generation and demand connections in the T1 period. The design of these mechanisms is a generation connection unit cost allowance (UCA) of £27/kW (£35.5/kW in 18/19 prices) and a demand connection UCA of £3.9m/SGT (£5.1/SGT in 18/19 prices) for substation works alongside specific overhead line and cable UCAs. Despite outturn costs forecast to be significantly greater than allowances across the portfolio of work delivered in both categories in the T1 period, we believe the mechanism to be a good starting point for the T2 period.

For T2 we designed a set of unit cost allowances for generation and demand connection volume drivers that more closely reflect the likely costs of the solutions, reflecting our learning in RIIO-T1. This led us to propose a suite of separate, tiered UCAs for these two categories that are more granular than those in T1.

Mechanism	Key aspects of our design
Generation connection	• Key cost drivers of substation, OHL and cables • Further differentiation between: o Air insulated vs. gas insulated substations o Existing vs. new substations o Connections <100MW vs. >100MW
Demand connection	• Key cost drivers of substation, OHL and cables • Further differentiation between: o Connection vs. infrastructure sites o (For infrastructure) SGT required vs. no SGT o Existing vs. new substations o Connections <50MVA vs. >50MVA

Draft determination

The draft determination does not progress our proposition for distinct generation and demand volume drivers.

Ofgem have instead advanced their own solution, which comprises of a combined generation and demand mechanism with key cost drivers for substation, OHL and cable work. Unit cost allowances for NGET are set at £8/kW (kVA) for substation work, £1.74m/km for overhead line work and £5m/km for cables in the Draft Determination document.

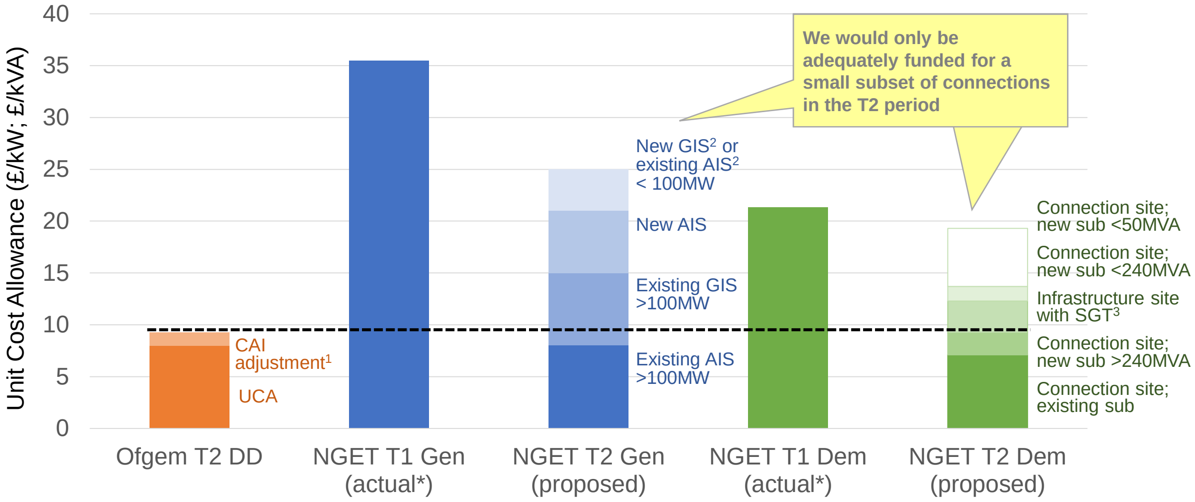
Ofgem have indicated they have doubts about the robustness of their proposals, but disappointingly did not provide any specific feedback as to why our proposed mechanisms are considered not suitable.

The volume driver in the draft determination is supported by the Medium Size Investment Project re-opener for 'outlier' projects that are >£25m and where the UCA is < 50% of the cost.

Our views on the draft determination

Most of the work required to connect generation and demand customers is undertaken at the substation. The OHL and cable UCAs were not used extensively in the T1 period. A simple comparison of Ofgem's proposed substation UCA with actual T1 values and our proposed tiered T2 UCAs, see figure below, shows that we would only be funded for a small proportion of the types of connection solutions we expect our customers will want us to deliver in T2.

Comparison of Ofgem T2 DD versus NGET T1 actual and T2 proposed unit cost allowances



* Adjusted from 2009/10 to 2018/19 prices (x 1.313)
[1]CAI - Closely Associate Indirects adjustment to account for these costs having been removed by Ofgem and funded elsewhere – assumed 16% on average
[2]GIS - Gas insulated Substation; AIS - Air Insulated Substation
[3]SGT - Supergrid transformer; proposed UCA = £12.53m/SGT with 240MVA capacity assumed

The following are examples of the types of connection that would not be adequately funded: (i) projects < 50MW in size, (ii) connections at new sites, (iii) many demand connections such as HS2 and (iv) demand increases at sites classed as infrastructure for charging purposes. We have provided a separate case study for each at the end of our response to this question.

Ofgem themselves note on p.78 of the NGET Annex that they "have significant reservations around these values". The proposed uncertainty mechanism for generation and demand in the Draft Determination is flawed and does not provide efficient funding because:

(i) The <u>uncertainty mechanism design employed is not robust</u>:

Generation and demand connections have been combined into a single uncertainty mechanism, despite being fundamentally different with different cost drivers, as evident from the diagram above. In seeking the simplicity of a single mechanism for both categories, the cost-reflectivity of the UCA has been reduced to the extent that it does not reflect our costs and is wholly unacceptable. This is completely at odds with Ofgem's limited consideration of our boundary capability UCA proposal, where cost reflectivity on a project by project basis has been the singular focus.

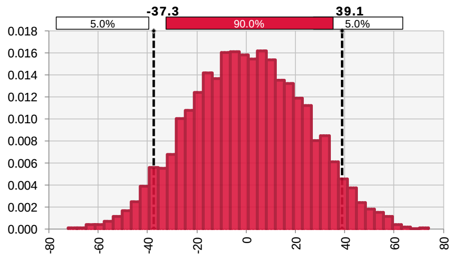
We propose that Ofgem **recognise these fundamental differences and revert to a separate generation and demand mechanism, as in T1.** We have provided conspicuous evidence of such differences, yet Ofgem is proposing a single mechanism with no justification as to why this should be a more suitable approach.

The choice of key cost drivers is not transparent and not sufficiently cost reflective to represent an equitable balance of risk between NGET and consumers. We have seen no evidence that the lessons learned from the operation of the T1 mechanism have been considered in the DD proposal. Our understanding is that the decision to limit the granularity to substation, OHL and cable has been driven by the desire for a single ET sector mechanism at the expensive of greater confidence cost-reflectivity.

The consequences for network companies and consumers of this decision is clearly illustrated in our Monte Carlo scenario analysis of the proposal in the DD compared with the more granular proposals we put forward in our business plan. Allowance vs. Cost performance can be measured across the 10,000 scenarios by comparing the mean and standard deviation of each resulting probability density curve. The model with a mean closest to zero (i.e. allowance minus cost averages 0) and smallest standard deviation (i.e. most likely to near the average) is cost-reflective and represents the most equitable balance of risk.

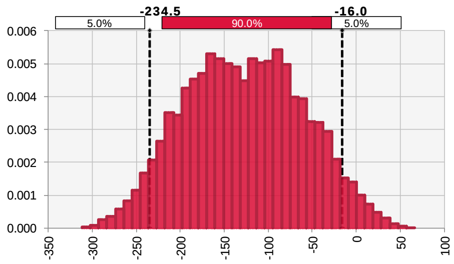
Generation

NGET Proposed UCA



Stats	
Minimum	-72.27
Maximum	73.90
Mean	0.728
Std Dv	23.26
Values	10,000

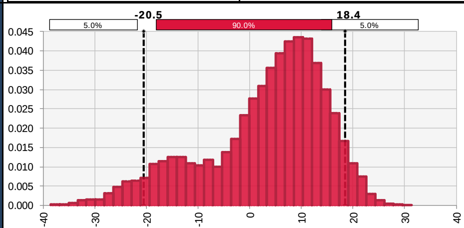
DD UCA



Stats	
Minimum	-311.53
Maximum	66.39
Mean	-126.75
Std Dv	67.12
Values	10,000

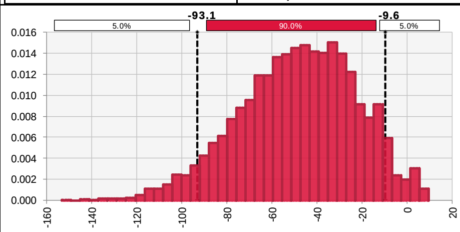
Demand

NGET Proposed UCA



Stats	
Minimum	-38.59
Maximum	31.31
Mean	3.044
Std Dv	11.87
Values	10,000

DD UCA



Stats	
Minimum	-153.08
Maximum	9.58
Mean	-48.40
Std Dv	25.80
Values	10,000

This assessment clearly shows the superior performance of a more granular UCA, such as that proposed in our business plan. The expected outcome of this approach is that allowance will match costs (mean approx. 0). The analysis also shows a likely departure of £23.26 in the event allowance would be greater or lower than costs. This is the size of the risks both NGET and consumes are exposed to under out proposed mechanisms. On the other hand, the expected outcome of the DD proposal is to spend £126m (mean) higher than allowance, with a likely departure of £67.12m. The demand UCA has similarly poor performance.

We propose that Ofgem **incorporate lessons from T1 and adopt a more granular, cost-reflective approach to design for connections in England & Wales, ensuring we are**

effectively funded to deliver efficient solutions for our customers and consumers are adequately protected. We provide more detail below.

The proposed mechanism would not provide funding for connecting whole-system solutions when the customers does not apply for TEC or the assets being connected have no MVA rating. Because of the ESO pathfinder process, we have received applications from several customers seeking to connect synchronised compensators and / or reactors to provide ancillary services to the ESO. As the market continues to develop, these types of connection will become more frequent. However, the proposed volume drivers would not provide allowances since the assets being connected do not require TEC nor have MVA rating.

We propose that Ofgem develop a **bespoke output measure to ensure these connections are funded through either the generation and demand volume drivers or an alternative funding arrangement is developed altogether**.

The mechanism only applies to projects delivering an output in T2 and therefore leaves a considerable funding gap for any new, uncertain connections our customers may require in the T2 period that deliver in T3 or beyond until T2 close-out. In addition, the lack of an ex-ante allowance for these projects reduces the efficiency incentive. Our analysis shows this could be a significant number of projects.

It is also not entirely clear how the set of projects starting and ending in T2 has been determined. There are several options for a threshold, linked to the level of expenditure outside the T2 period, or linked to specific milestones expected within the period. Using our T2 business plan to illustrate, the following table provides the proportion of projects that would typically be expected to qualify for the mechanism using different thresholds for 'delivering in T2'. Although this is simply an illustration as baseline projects are funded, it shows there is a high likelihood that new projects will not be funded through the Draft Determination approach.

Threshold	% Generation projects	% Demand projects	% Total Projects
£0m outside RIIO-T2	16%	0%	12%
<£0.5m outside RIIO-T2	41%	31%	38%
Gate B and Output in RIIO-T2	14%	0%	10%
Gate C and Output in RIIO-T2	35%	8%	28%

We propose Ofgem **either apply the UCA to projects delivering beyond T2 (similar to the T1+2 approach) <u>OR</u> introduce another route for funding new projects in the T2 period that deliver beyond T3, so this material funding gap is eliminated.**

The proposed utilisation of both the UCAs and PCD secondary deliverables + ex-post assessment to adjust baseline allowances is fundamentally flawed. The move to ex-post assessment considerably increases uncertainty for network companies, which will delay connection projects and will remove the incentive to drive efficiency and innovate.

Ofgem's proposed ex-ante UCA that will adjust allowances up and down automatically is incompatible with an ex-post assessment against PCD secondary deliverables.

We propose Ofgem **calculate robust, cost-reflective UCAs that can be applied ex-ante to increase certainty for network companies, continue to incentivise innovation and drop the unnecessary ex-post assessment as the two approaches are incompatible.**

If an approach to managing uncertainty with robust UCAs is put in place, the use of the MSIP re-opener to deal with outliers will be much less frequent. Nevertheless, we have concerns about the implementation of what seems an arbitrary threshold to qualify for the re-opener, which is more onerous than the threshold set in Ofgem's common approach to re-openers. Ofgem have not been able to share their analysis undertaken to establish the optimum threshold with us.

The proposed approach for the treatment of outliers, which are >£25m and where the UCA funds <50% of costs, could result in material gaps in funding up to a maximum of £49m per project (i.e. £99m x 49%) and introduces perverse incentives at the edges for companies to access a route to funding.

For example, a [redacted] CCGT connection requiring £23m of efficient investment would only attract £12m of allowances. However, should the TO incur £2.1m of additional spend, to bring it into scope of the MSIP reopener, it would receive additional funding, even if the £2.1m of inefficient spend was disallowed; i.e. £23m (a £2.1m deficit) vs £12m (an £11m deficit)).

A well-designed uncertainty mechanism should not require a threshold of any kind. If one is maintained, we propose Ofgem **adjust the threshold to remove the £25m requirement, lower it and make it symmetrical to include all projects where the UCA funds >125% or <75% of costs**, which would lower the maximum exposure on a single project to £24m (i.e. £99m x 24%). **Implemented alongside a more robust UCA, this would present a more acceptable level of risk for both companies and consumers and remove any need for PCDs with Secondary Deliverables.**

If cost vs. allowance performance is an area of concern other simple mechanisms, such as a symmetrical cap / collar on % of expenditure are also available and would allow projects to progress without the risk of delay from having to go through a re-opener process.

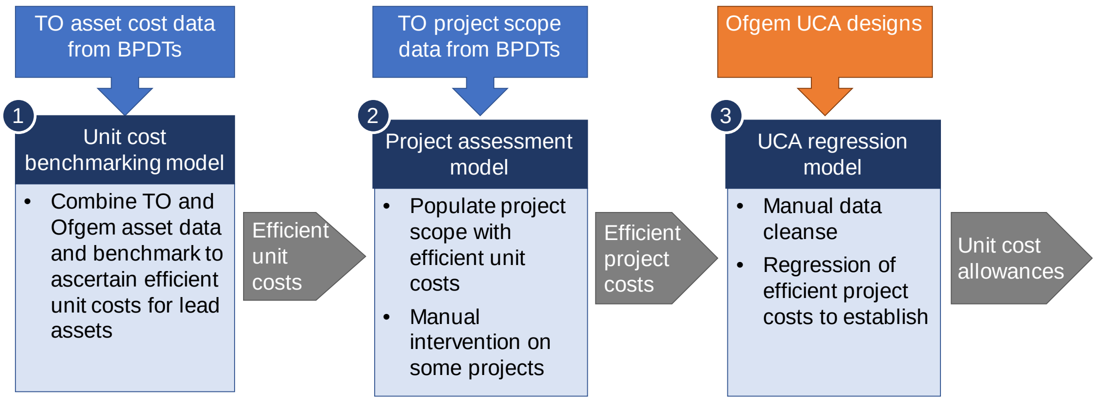
We have provided more on our views on the MSIP mechanism in response to ETQ13.

(ii) The <u>methodology used to arrive at a UCA is not robust:</u>

Given the starting position for baseline allowances was based on the low end of the ranges in the Common Energy Scenario and the need to transition to net-zero, the UCA is highly likely to act to increase allowances over the T2 period.

Compared to a baseline starting position that is a P50 of likely outturn (i.e. the UCA would be equally likely to increase as decrease over the period) there is less of an incentive for both parties to arrive at the most cost-reflective UCA.

Our understanding is that the regression model used to calculate UCAs was fed input project data from the Project Assessment Model (PAM), which in turn was fed input data from Ofgem unit cost benchmarking model, as shown in the figure below.



We have concerns for each step in this process

1) Unit cost benchmarking model

We believe Ofgem have incorrectly calculated the unit costs at the basis of their efficiency assessment. We've summarised some of key issues we identified below:

- The lack of Ofgem guidance has meant TOs have reported costs in an inconsistent manner, which in turn has resulted in Ofgem benchmarking model incorrectly removing efficient costs (e.g. civils).

- The dataset used to determine the efficient unit cost (which contains both Load and Non-Load projects) does not consider the difference in detailed scope and drivers across the two portfolios (e.g. establishing new infrastructure or uprating assets to meet a load related driver as opposed to replacing existing assets) and results in unit costs that are not representative. This is shown clearly in the 'Non-load projects vs load connection and infrastructure site projects' diagram towards the end of this section.
- The disaggregation of project costs into component parts does not necessarily give a clear view of the realistic, efficient cost of delivering projects. For e.g., the unit cost only refers to asset costs such as transformers and non-asset costs such as civils. Indirect costs such as design, network planning and project management are assessed separately being classed as Indirect Opex. This approach prevents true calibration to historic performance as capital investments have traditionally been reported including all associated costs not just direct costs.

2) Project Asset Model (PAM)

Issues also exists with the way unit cots have been applied via PAM to derive an efficient level of allowance for each of the projects in our business plan. The approach taken has been to cap costs at the benchmark unit costs, but where submitted costs are below the average these are retained. This perversely rewards TOs whose costs are consistently higher than the average as the resulting allowances will be at the efficient unit cost; compared to a true portfolio with projects above and below the efficient unit cost where allowances will end up either at or below the efficient unit cost. As an approach it does not recognise the natural spread of costs that would exist in a price control period and variation in nature of projects.

3) Unit Cost Allowance (UCA) regression model

The regression models used to arrive at the Draft Determination suffer from serious statistical issues and **the UCAs they estimate account for little more than random number generation**.

Despite the 100 demand and generation projects made available, the UCAs have been estimated using only 14 data points, leading to results that are not statistically robust. Whilst Ordinary Least Square (OLS), the estimator used, has desirable small sample properties, the size of the sample is undoubtedly too small.

When a regression is run on such a small set of data, results become very sensitive to its composition and selection criteria. This means the proposed UCAs could be very different if for example one or two projects were added or removed.

This 'sampling uncertainty' can be intuitively observed in the Confidence Intervals associated with Ofgem's own model, which are shown in the table below.

UCA	lower 95% range	DD	Upper 95% range
Substation	0.004587	0.007839	0.01109
OHL	-1.03217	1.740946	4.514065
Cable	2.298521	10.36496	18.4314

Confidence Intervals represent the range within which the model coefficients (i.e. UCAs) could be and therefore indicate the uncertainty around the model results. The ranges in the table above are quite broad – for example, the cable UCA could be anywhere between £2,300/kW to £18,000/kW; and the OHL UCA could even be negative, which is implausible.

We understand the small sample size is the result of the decision to restrict the regression analysis to schemes in the baseline only, along with a number 'filters' applied to the PAM output to remove schemes deemed unsuitable (e.g. outliers) from the regression input dataset.

This approach is not statistically sound and will not work in practice. These mechanisms will be funding new connections that are likely to be different from those in the baseline. It's clear the UCAs should be estimated from the widest possible dataset representative of the broadest set of connecting solutions that we might have to deliver. This is the only way to ensure the UCA approximates the 'true' average cost of a connection.

Ofgem's 'restrictive' approach goes in the opposite direction. It's not surprising there's significant uncertainty around model results and the proposed UCAs are only representative of a small subset of the connecting solutions we normally deliver, as shown in table below.

Limited input data used for regression		
Connection type	**Substation works**	**Busbar technology**
Exit	Construction of a new substation	AIS
Entry	Extension of existing site	AIS
Entry	Extension of existing site	GIS
Entry	Extension of existing site	GIS
Entry	Extension of existing site	GIS
Entry	Extension of existing site	AIS
Exit	Extension of existing site	AIS
Entry	Construction of a new substation	GIS
Entry	Construction of a new substation	GIS
Entry	Extension of existing site	GIS
Exit	Extension of existing site	AIS
Entry	Extension of existing site	AIS
Entry	Extension of existing site	AIS

We urge Ofgem to **include both baseline and uncertain schemes in the regression dataset as well as reviewing the 'cleansing' criteria, to ensure the sample is sufficiently large and comprises of a mix of schemes that is representative of what we might be required to deliver in the future.**

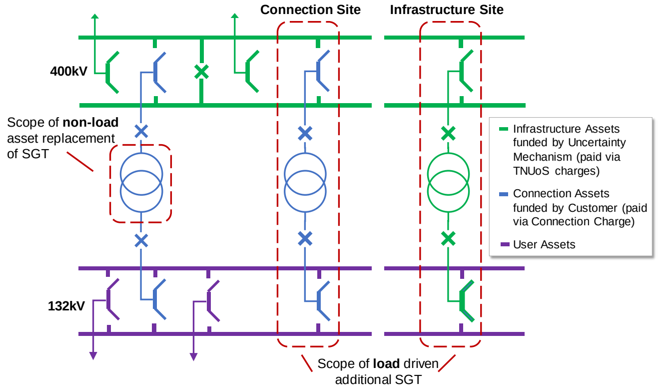
To increase the sample size, Ofgem have decided to 'pool' demand and generation projects together, as such creating a broad cost driver (generally defined as 'electrical output') encompassing both MW or Transmission Entry Capacity (TEC) along with MVA of transformer capacity.

There are a number of reasons why TEC and MVA of export capacity should not be fed into a regression as the same unit. The infrastructure works required to deliver an additional MW of TEC is substantially different from that associated with an additional MVA of export capacity; the ownership boundaries between generation and demand customers are different; and the size of generation connections vary to a much greater extent. This would normally result in the cost driver being rejected by the model.

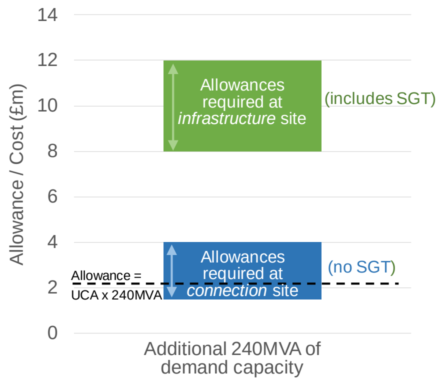
Whilst 'electrical output' appears statistically significant in the Draft Determination models, we believe this is likely because the number of generation projects in the sample (11) far outweighs the number of demand schemes (3). As a result, the proposed substation UCA is mainly representative of TEC.

The line diagram below illustrates the peculiarity of demand connections and why they are so different to generation connections. Depending on the ownership boundary at a particular substation, the supergrid transformer (SGT) could be a connection asset, which is funded by the customer (connection charges) and excluded from price controls or an infrastructure asset, which is funded through the price control (and recovered through TNUoS charges). This difference has a big implication for the cost of additional demand capacity at a given site, as shown below and expanded on in '*Case Study 4 – Connections at 'infrastructure' sites are systematically underfunded'* *at the end of our response to this question*.

Scope of non-load projects vs load connection and infrastructure site projects



Cost vs Allowance for a typical additional demand capacity of 240MVA at sites with different ownership boundary



We reiterate that **separate UCAs for generation and demand are the only way to ensure the mechanism has sufficiently cost reflective allowances.**

Several additional problems affecting the robustness of Ofgem models exists. For example, the OHL UCA is not statistically significant (i.e. it could be 0), this would lead to the rejection of OHL km as a meaningful cost driver.

Similarly, we cannot discount that the model may suffer from endogeneity, serial correlation and / or heteroskedasticity. These are basic conditions that must be met to ensure regression results are reliable. Ofgem have not performed any diagnostic tests to ascertain this and the extremely small sample size means visual inspection of the model residuals is meaningless.

Developments since the Draft Determination

We have been engaging with Ofgem on several issues related to the proposed demand and generation UCAs since we received the underlying data, two weeks after Draft Determination.

As part of this process, it emerged that the regression model was using project input data from an outdated version of the PAM model, which needed updating. On the 17th August we received an updated version of the PAM along with an updated set of UCAs.

On one hand, we note the sample size has increased to 33 and the basket of schemes fed into the regression no longer comprises of baseline schemes only. We welcome these as positive improvements. On the other hand, we are disappointed generation and demand schemes continue to be 'pooled'. We can also observe the models continue to suffer from severe statistical issues affecting the robustness of results.

The table below compares the UCAs proposed in the DD document with those updated following the re-run of Ofgem regression model.

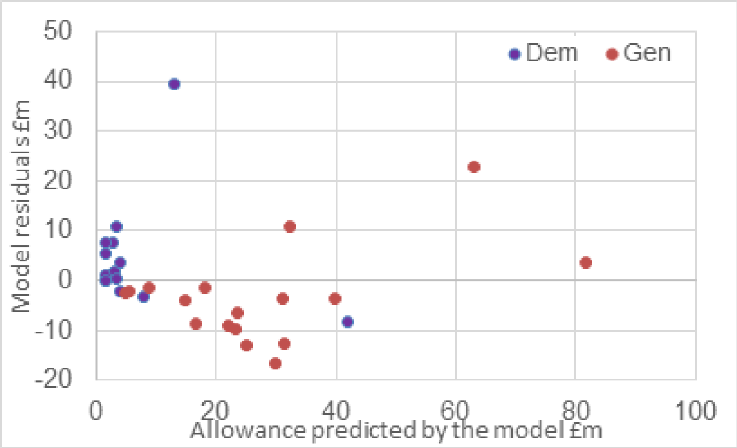
UCA	Draft Determination	Updated Ofgem model
Substation	0.0078386	0.016632
OHL	1.7409462	0.833978
Cable	10.364961	1.387097

The effect of changes in size and composition of the sample are obvious, with the substation and OHL UCAs approximately doubling and halving respectively. Whilst some of this variation may appear positive, it casts serious doubts on the robustness of the models. To compound these concerns, the cable UCA is no longer statistically significant whilst the OHL UCA is.

The confidence intervals for the substation and OHL UCAs continue to be large as well as implying implausible results for the cable UCA, as shown in table below.

UCA	Lower 95% range	Updated DD	Upper 95% range
Substation	0.012905	0.016632	0.02036
OHL	0.564184	0.833978	1.103772
Cable	-0.4715	1.387097	3.245696

The graph below shows a visual examination of the regression results, which is now possible due to the increased in sample size.



The graph, which plots the regression residuals (i.e. the difference between Ofgem's view of efficient scheme costs and the allowance generated by the Ofgem UCAs) on the y axis against the allowance predicted by the model on the x axis, illustrates very clearly the lack of cost-reflectivity of the revised UCAs along with the problems resulting from pooling demand and generation schemes together.

It can be seen the revised UCAs systematically underfunds demand schemes (points above zero means cost are greater than allowance and vice versa) whilst almost always over-remunerate generation connections.

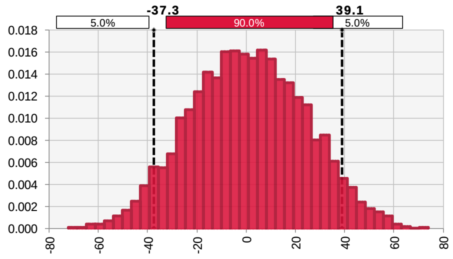
Beside the lack of 'poolability' resulting from the clustering of demand and generation schemes, the larger data sample now reveals that the model could also be suffering from heteroskedastic (i.e. the delta between allowance and costs seems to increase as we move along the x axis), which in turn suggests some t-statistic could be wrong and some form of robust estimation might be required. As a result, the statistically significance of the cost drivers as implied by the model might change.

We have also tested the updated DD model against the more granular UCAs we put forward in our business plan. This involved testing both mechanisms against 10,000 different scenarios to ascertain whether they start at a balanced position as well as providing an equitable balance of risks between NGET and consumers. The results of our Monte Carlo analysis are shown below.

	NGET Proposed UCA	DD UCA

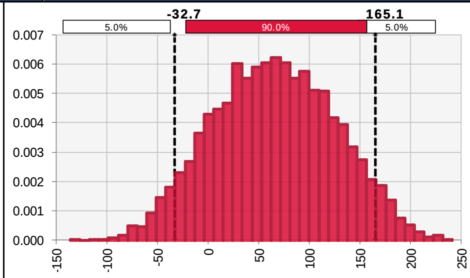
Generation

NGET Proposed UCA



Stats	
Minimum	-72.27
Maximum	73.90
Mean	0.728
Std Dv	23.26
Values	10,000

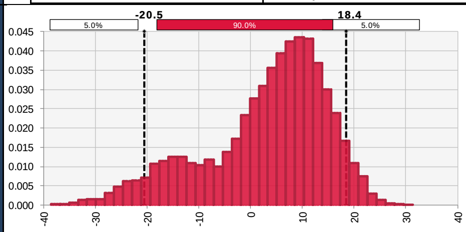
DD UCA



Stats	
Minimum	-135.86
Maximum	241.55
Mean	65.58
Std Dv	59.86
Values	10,000

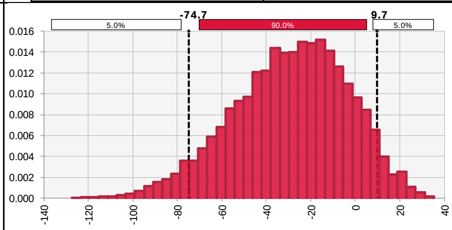
Demand

NGET Proposed UCA



Stats	
Minimum	-38.59
Maximum	31.31
Mean	3.044
Std Dv	11.87
Values	10,000

DD UCA



Stats	
Minimum	-127.50
Maximum	35.24
Mean	-29.07
Std Dv	25.75
Values	10,000

Whilst an improvement in performance is visible relative to the DD, the analysis confirms the general lack of cost reflectivity and poor allocation of risks, with NGET being most always underfunded and overfunded for demand and generation connections respectively. Our original proposal still performs more robustly and therefore better minimises risks for company and consumer.

Case studies – supplementary evidence

[redacted]

[redacted]

[redacted]

[redacted]

ETQ13C Shunt reactor unit cost allowance uncertainty mechanism

Context

The reducing demand for reactive power in recent years, resulting from decentralised generation and changing consumer load types, leads to a surplus of reactive power. This surplus causes system voltage levels to increase under certain network conditions. High voltages can cause damage to equipment and safety issues.

Both as a result of changing system requirements and the potential for alternative solution providers, the approach to funding shunt reactor investment needs to be sufficiently agile to deliver the associated consumer benefits in a timely manner.

For T2 we set out to design a set of unit cost allowances for shunt reactors to facilitate this. We investigated three, unit cost allowance models for static reactive compensation, using an input dataset of 33 historic and forecast schemes and proposed an approach based on compensation capability delivered as having the most robust cost-allowance performance. A unit cost allowance for dynamic (i.e. variable) compensation was also proposed, as set out in the table below.

Mechanism	Key aspects of our design
Static reactive	Based on capability delivered from standard unit sizes: 60MVAr: £m/MVAr 100MVAr: £m/MVAr 200MVAr: £m/MVAr
Dynamic reactive	Based on the maximum reactive capability delivered: £m/MVAr

Draft determination

Ofgem's consultation position is that:

Subject to further information from the TO's, set volume driver(s) to fund the installation of additional shunt reactors, which is supported by a request from the ESO.

The form of the volume driver could be based either on the unit cost of the capacity installed £/MVAr, or on the unit cost of the number of individual units installed £/unit.

Either form could be a single rate regardless of the size or type of reactors installed, or a suite of rates reflecting such differences. If the data available does not support the derivation of robust ex-ante volume drivers, then we propose to use a re-opener mechanism instead.

Ofgem note that the TOs have indicated a range of sizes and types, with a wide spread of costs in terms of per unit capacity or per unit equipment. In the consultation they seek further evidence from TOs to support design of robust volume drivers.

Our views on the draft determination

An agile funding mechanism for this type of investment is important given the likely high volume of reactive compensation investments required in T2 to manage the changing nature of the network. The low baseline allowances we have requested reflect the fact that whole system options can play a large role in reactive compensation provision. We are seeking to facilitate the emerging whole system processes (e.g. the ESO pathfinders) by using a volume driver to fund NGET investments only after they have been identified through these whole system assessments.

The impact on ESO network operating costs of not having appropriate levels of reactive compensation in place can run into the 10s of £millions per annum and this is detrimental to consumers.

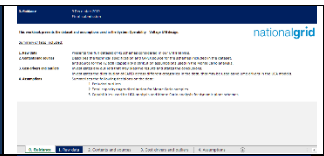
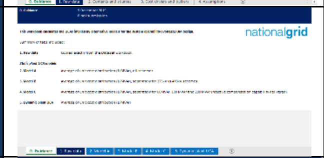
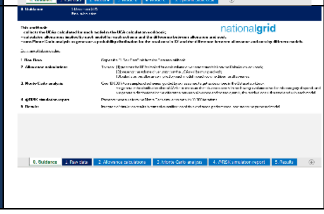
Our views on the draft determination are in two areas: (i) whilst we welcome a conversation with Ofgem about how a unit cost allowance can be made to work, we disagree that TO's need to submit more evidence that a robust UCA can be designed and (ii) a re-opener mechanism will not be sufficiently agile and will would need a bespoke design to ensure consumers don't lose out if implemented. More details and our proposed approach are set out below.

(i) Whilst we welcome the opportunity to work with Ofgem to implement a workable ex-ante automatic unit cost allowance, we disagree that TO's need to submit more evidence that a robust UCA can be designed.

In preparing our business plan we undertook detailed design work on an extensive input data set, that included both historical actual costs and forecast costs for future investments and tested our unit cost allowance proposals using Monte Carlo analysis. A summary description of the approach, models considered and results for our System Operability – Voltage UM can be found on p.51 of our Uncertainty Mechanism Annex to our business plan:

https://www.nationalgrid.com/uk/electricity-transmission/document/132116/download

Summary information in our UM Annex was submitted to Ofgem alongside 3 separate, detailed and annotated Excel Workbooks, described below.

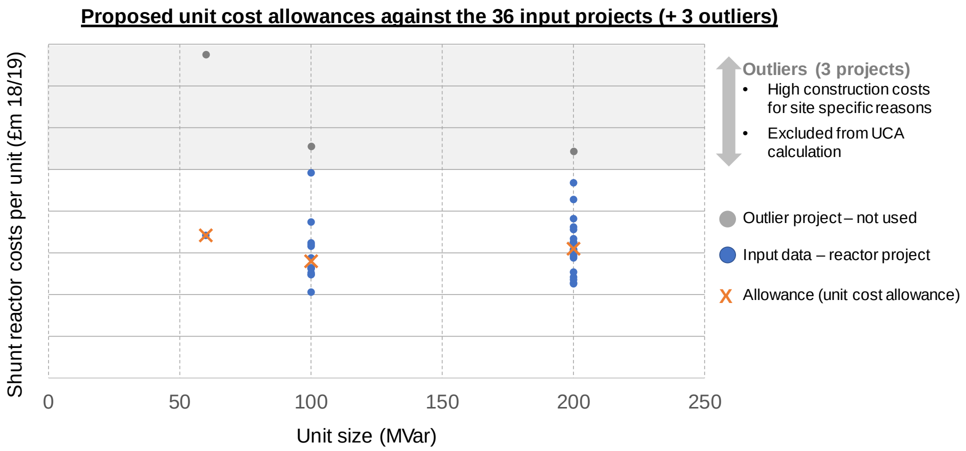
Workbook 1 - Inputs		Presents the input dataset and assumptions used in our unit cost allowance design
Workbook 2 - Design		Calculates the UCAs implied by alternative models for UM design
Workbook 3 - Testing		Calculates allowances implied by the UCAs of each model, the difference between allowance and cost, and runs Monte Carlo analysis to generate a probability distribution for the difference between allowance and cost across 10,000 T2 investment scenarios for each model

Our input dataset contained 36 reactor projects (+ 3 outliers that were not used) and to arrive at our proposed design we considered 3 different models for static reactive compensation and 1 model for dynamic reactive compensation.

36 input data points is enough to develop a robust UCA. We note that the generation and demand substation unit cost allowances proposed in the Draft Determination were based on only 14 input projects for NGET.

A range of costs is to be expected when delivering projects due to specific circumstances at the substation where the reactor unit is to be located. Factors driving these differences include whether the substation is air or gas insulated, how much space is available on site – affecting the length of cross-site cable required, whether a spare bay is available or not, the potential need to reconfigure adjacent assets or acquire additional land, varying ground conditions affecting civil costs, etc.

The graph below plots the allowances from our proposed static compensation unit cost allowances against the input data used and shows the range of costs associated with the projects used for input data. The intention of a unit cost allowance is to provide appropriate allowances across a portfolio of projects that networks could be required to deliver across the price control. Inherently, this approach accepts variability between costs and allowances for individual projects, as seen in the below graph.



The natural cost variability, a feature of all projects in our business plan, does not hinder the development of a robust UCA.

Testing of a given unit cost allowance design against a number of investment scenarios that are plausible over the T2 period is how sufficient confidence is obtained across a portfolio of projects that could need to be delivered.

We developed 3 separate models for our static reactor unit cost allowances (the type most likely to be deployed) and 1 model for our dynamic reactive unit cost allowance proposal, as set out below.

Static Reactive Power Compensation models considered:

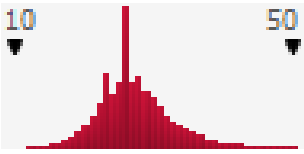
- **Model A:** UCA per MVAr of new static compensation capability delivered, (£/MVAr) assessed through unit cost distribution analysis
- **Model B:** UCA per MVAr of new static compensation capability delivered (£/MVAr), split by connecting substation voltage, assessed through unit cost distribution analysis
- **Model C (proposed):** UCA per MVAr of new static compensation capability delivered (£/MVAr), split by level of compensation capability delivered, assessed through unit cost distribution analysis

Dynamic Reactive Power Compensation

- **Dynamic Model:** £/MVAr reactive power capability delivered

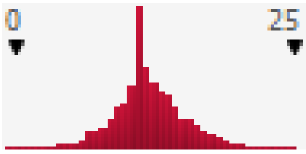
The testing of these models to ascertain whether any provided sufficient confidence in cost vs. allowance performance was done using Monte Carlo analysis across 10,000 possible investment scenarios that we could have to deliver in the T2 period. This modelling showed that Model C (with a mean of 0.64 and standard deviation of 1.86) has good cost vs. allowance performance and is the most robust against all models considered for static reactive compensation, as shown in the table below:

Model A



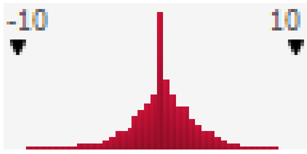
Stats	
Minimum	13.61
Maximum	49.66
Mean	27.60
Std Dev	4.39
Values	10,000

Model B



Stats	
Minimum	0.26
Maximum	24.34
Mean	12.23
Std Dev	2.67
Values	10,000

Model C (proposed)



Stats	
Minimum	-8.54
Maximum	8.29
Mean	0.64
Std Dev	1.86
Values	10,000

We have been very transparent with our input data and assumptions, the unit cost distribution analysis undertaken to ascertain unit cost allowances and the Monte Carlo testing undertaken. The 3 workbooks submitted as part of our business plan contain all this information and models (that can be re-run with different assumptions).

The Draft Determination and underlying detail that we have seen does not indicate what the issue with the proposal in our business plan is.

We have demonstrated that the proposal in our business plan is robust and would welcome a conversation about the conclusion in the Draft Determination that more evidence is required.

(ii) A reopener mechanism will not be sufficiently agile and would need a bespoke design to ensure consumers don't lose out due to solutions not be delivered in time.

The medium size investment project reopener is the mechanism in the draft determination that would seem to be where the need for additional shunt reactors would be funded. As set out above, this approach is not agile enough and would need a separate uncertainty category, with unique design characteristics to mitigate negative consequences such as delays to delivery.

An approach for reactors would need to address (a) the window for applications and (b) the materiality threshold.

a) The draft determination currently proposes a single January 2024 re-opener window and ex-post true up. Given the dynamic nature of these projects, as described above, a single re-opener window is too restrictive to allow investment to progress in a timely manner. To maximise consumer benefit, the process should not have any restrictions on when applications can be made – i.e. they should be able to be made on an ad-hoc basis when a need becomes clear.
   Ex-post true-ups remove the incentive to innovate and reduce costs. In addition, for this category of investment, where costs are highly certain and relatively small the administrative burden is not proportionate.
b) The common approach to re-openers would indicate a materiality threshold of 1% of average annual baseline revenue for this type of project, which is in the order of £15m for NGET. The chart above, showing input projects and allowances provided by our proposed unit cost allowance, shows that this threshold would leave a funding gap for all reactors except extreme outliners. To maximise consumer benefit, the process should not use a materiality threshold.

The Draft Determination refers to an MSIP category of ESO-driven requirements, which could be used if a reopener approach was necessary. The Draft Determination also points to the development of an additional process by Ofgem with the ESO and TOs, similar to NOA, for this purpose. We would welcome the opportunity to be involved in the development of this process, which would need to consider the design points raised in (a) and (b), above, amongst other things.

A reopener approach is not agile enough to deliver consumer benefits in a timely manner. If such an approach is pursued, barriers such as windows and materiality thresholds should be removed to maximise consumer benefit. The new process for ESO-driven requirements could be developed to work for reactors.

Developments since the Draft Determination

There has been insufficient time to cover this issue since having received the full detail behind the draft determination. We would welcome engagement on this topic to ensure a sufficiently agile funding mechanism can be put in place.