SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

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Core Methodology, 7. Delivering at lowest cost to energy consumers

Question ID	Core-Q63.
Question	**Do you agree with our proposed approach to pre-modelling normalisations and adjustments?**
Associated Evidence	
Title	**Link to Evidence**
Cost Assessment Annex E	n/a
Cost Assessment Annex F	n/a
North of Scotland Annex 10	n/a
Environmental Annex 8	n/a
Response	

We disagree with Ofgem's approach to pre-modelling normalisations and adjustments.

We have identified a series of errors in the pre-modelling adjustments made by Ofgem in the DDs which must be corrected at FD. The main errors in Ofgem's approach affecting SSEN are:

Regional Factors:

Regional wages: In its DD Ofgem has proposed not to make a pre-modelling adjustment to account for high labour costs in Scotland. Ofgem's reasoning for not including a regional wage factor for Scotland, based on the idea that labour mobility will normalise wage rates, is wrong. There is clear and robust evidence to show that the regional wage effect extends to Scotland and that this effect has been persistent throughout RIIO-ED1 and earlier. We have included analysis from Oxera (see Cost Assessment Annex E) that demonstrates that the UK is characterised by minimal labour mobility. Moreover, this low level of labour mobility has reduced even further in recent years with the tightness of the labour market. This is particularly acute in the energy sector (the highest rate of growth in vacancies, at 16%, is in electricity, gas, steam, and air conditioning supply sector). More detailed analysis and evidence showing that regional wages in Scotland are persistently above the rest of the UK support our case for a regional wage factor for SHEPD is provided (see Cost Assessment Annexes E and F). Ofgem must include a regional wage adjustment for SHEPD in final determinations.

Sparsity: Ofgem has rejected sparsity as a regional factor based on analysis within a memo table submitted within our December Business Plan. No clear guidance was provided by Ofgem on how this memo table would be utilised, so RIIO-ED1 data input was based upon allowances at the RIIO-ED1 Final Determinations, as opposed to the costs we had actually incurred during the period. We are submitting an updated memo table which shows the average annual costs are similar between the price control periods (North of Scotland Annex 10).

Ofgem further argue that sparsity may impact other DNOs to some extent, but we believe this argument to be flawed and inconsistent as it could also be equally argued that high urbanity may impact other DNOs to some extent, and by the same logic there should be no London regional wage effect. The purpose of our claim is to normalise for the extreme level of sparsity and islands that no other DNO experiences, due to the high percentage of very highly sparse areas including islands that SHEPD has to manage.

Ofgem's argument that they would expect the performance of both SEPD and SHEPD to be materially similar is also flawed and does not reflect Ofgem's own previous assessment of performance of networks under common ownership. Comparison of network performance under common ownership is not informative of the need for making a regional adjustment, and common ownership does not imply the same relative levels of efficiency. For example, within the RIIO-ED2 assessment the WPD's networks efficiency ranges from -16.8% to -23.8% and within the RIIO-GD2 assessment Cadent's networks efficiency ranged from -5% to -14%. In RIIO-GD2 this difference between efficiency scores existed even after the application of a sparsity index.

Finally, top-down econometric modelling undertaken for SSEN by Oxera (included in Cost Assessment Annex E) shows that, for SHEPD, a sparsity/Islands variable is both positive and significant and demonstrates higher costs for sparce DNOs such as SHEPD. The incremental impact for SHEPD's cost allowance identified by Oxera's top-down modelling is consistent with the bottom-up quantification submitted in the SSEN business plan. Ofgem must therefore allow this regional factor claim in full at final determinations.

Company Specific Factors:

Cost of Islands: As with Sparsity we have submitted an updated memo table to show the true average annual change for RIIO-ED1 and RIIO-ED2 costs, which show the average annual costs are similar. To provide further evidence we have also submitted a supplementary North of Scotland annex (Annex 10) which explains in detail the need and justification for these company specific factors.

Also as discussed previously the pre-modelling claim is aligned with an in-modelling based assessment, which validates the efficiency of our company specific factor claim.

Subsea Cables: We appreciate Ofgem's acknowledgment of the additional expenditure incurred due to our extensive submarine cable portfolio in Scotland. While we do optimise our activities in this space, this is an area of expenditure that includes factors that are outside of our overall control and not comparable to any other DNO. Ofgem have claimed that we have not provided enough evidence to justify the expected cost increase in RIIO-ED2 so we have provided further supporting evidence of our analysis and reasoning for why the evidence shows that our proposals for managing subsea cables in RIIO-ED2 are in the best interests of customers and wider stakeholders. It should be noted that, due to the atypical and lumpy nature of expenditure of subsea cables, it is not appropriate to analyse expenditure by simply comparing periods of time. We therefore ask Ofgem to utilise the data and stakeholder-led evidence we have put forward.

From a modelling perspective, Ofgem should also ensure that, due to the unique nature of subsea cable expenditure, all costs are excluded from benchmarking, and any efficiency assessment is carried out independently of the benchmarking process, and added back post modelling. Not removing valid company or regional factor claims within the modelling will have an impact on the overall model quality and accuracy of the models, with other DNOs efficiency artificially increased. A company or regional factor claim should be assessed independently of the modelling performance.

Cost Exclusions:

We accept the proposed cost exclusions but also suggest Ofgem consider the following:

Worse Served Customers (WSC): with this area being accepted as submitted, to include the cost within Totex modelling causes an adjustment to be made and counters the methodology that Ofgem proposes in its core methodology. This appears to be an error. Furthermore, WSC is an area that DNOs are exposed to differently and that is not within management control. Due to the differing impact the amount of WSC expenditure required for each DNO is not explained through any drivers otherwise used in the modelling suite.

Environmental Expenditure: more than ever, DNOs are being challenged to reduce emissions and help to deliver net zero goals. The starting position and goals for each DNO differs, with some DNOs more exposed to urban areas which can impact DNO vehicle fleets, and others with more challenging targets such as the Scotland goal of reaching net zero by 2045, five years earlier than the rest of the UK. We note that our own 1.5° Science-Based-Target (SBT) includes losses as a scope 2 emission, takes a different approach to residual carbon emissions through nature-based solutions, and is rendered further challenging given the current reliance on diesel generation to ensure security supply on the islands.

By including these differing targets within the modelling, particularly Totex modelling which has no appropriate driver to account for these differences Ofgem is creating a blocker to DNOs being able to deliver their unique Net Zero challenges. Environmental expenditure should be excluded from totex modelling, with a disaggregated model approach sympathetic to DNO requirements (see Annex 8 and CORE-Q13).

IT/OT: IT and OT schemes are a requirement to deliver the goals of RIIO-ED2 as set out by Ofgem, to help deliver Net Zero while also overall increasing value for money to customers. Ofgem's framework also introduces new obligations in the digitalisation space, which must be supported by sufficient funding. Ofgem state they want to drive to technology neutrality in RIIO-ED2 and acknowledge that DNOs enter the price control at different starting positions. Ofgem therefore counters its methodology by including IT and OT expenditure within Totex modelling, as there is no driver within the models to account for differing starting points within technology. Ofgem should exclude IT/OT expenditure from Totex modelling and utilise more disaggregated assessment, as per our comments within CORE-Q79.

Other Adjustments:
Reallocation between cost activities: we acknowledge and accept the reallocation of NoSR from CV15 to CV19 for consistency with other DNOs. We have commented further within CORE-Q83.

Reallocation from memo tables: while we understand the adjustments that have been made in regards of M13 Uncertainty Mechanisms to CV2 Secondary Reinforcement we are concerned that the movement further widens the gap for comparison between DNOs. We have commented in more detail in response to CORE-Q4.

In addition, within section 7.78 of the core methodology document Ofgem have explained that they have reclassified the M13 costs associated with ENWLs Ash Dieback and Diversions UM into the baseline ask:
ENWL: £89m of forecast cost for LRE uncertainty mechanisms and £97m of forecast costs for diversions, tree cutting (ash dieback) and environmental reporting (PCBs)

It is unclear why these costs have been reclassified for ENWL, but the same costs have not been reclassified for SSEN given that our own forecasted cost and volumes have also been split between a baseline ask and the proposed uncertainty mechanisms. **For the avoidance of doubt**, our baseline costs/volumes are those we have certainty on, whereas the UM costs are those we cannot guarantee given the uncertain natures of these activities. However, both the baseline and UM together make up our forecasted cost/volumes. As with ENWL, if Ofgem continue to reject the proposed UMs we would require the costs associated with these to be reallocated to the baseline. However, before doing so we would ask for further engagement with Ofgem to agree what costs are appropriate to add into the baseline given the risks associated with these uncertain forecasts.

Reallocation from CVP to Baseline: we disagree with the reallocation put forward for SSEN as per SSEN-Q8.

Overall, we have concerns with the normalisations and adjustments applied pre modelling and welcome further work with Ofgem and the CAWG to ensure assessment can be made on a fair and transparent basis.

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Question ID	Core-Q64.
Question	Do you agree with our approach to totex benchmarking?
Associated Evidence	
Title	**Link to Evidence**
Cost Assessment Annex E	n/a
Response	

We broadly agree with Ofgem's approach to totex modelling. However, we do highlight a number of issues below. Indeed, Ofgem's proposed totex modelling is generally a positive improvement: the CSV (especially in totex 1) is now broader and customer numbers no longer has counterintuitive weight, which is an issue that we had previously highlighted.

Demand Drivers

In addition to the required pre-modelling adjustments (see CORE-Q63), we have some specific key issues that need to be addressed, namely around the appropriateness of the weightings of the LCT cost driver, which does not sufficiently account for the impact of EV chargers on costs.

Due to the larger volume of EV chargers over ED2 and so their larger impact on costs, EV chargers should have a higher weighting. Analysis carried out by Oxera in Cost Assessment Annex E with EVs and HPs weighted on the volume submitted suggests that model fit improves by utilising a more operationally intuitive weighting.

MEAV Exclusions

We note that Ofgem are proposing to utilise what was referred to within CAWG meetings as "Pure MEAV" without any exclusions. We disagree with this approach as fundamentally the driver should be the explanatory variable for costs. By including within the driver such things as Rising and Lateral Mains (RLM), while this cost is excluded through pre-modelling adjustments creates a disconnect and undermines the quality of the modelling. We note in para 7.120 Ofgem comment the reason to include RLM is to capture the impact to indirect expenditure related to RLM, but we would counter that this element of expenditure is lower than the direct cost so the benefit being created is inflated. To correctly account for any significant indirects associated with RLM Ofgem, should utilise a cost exclusion, tied with the original direct cost exclusion.

Ofgem should exclude appropriate elements of the MEAV driver to align with the cost exclusions, primarily being RLM and Subsea cables.

Time Periods

We acknowledge Ofgem's appreciation of the structural change between the RIIO-ED1 and RIIO- ED2 periods due to differing expectations and requirements. Despite this acknowledgement we believe through Ofgem utilising actual (2016 – 2021) and forecast (2022 – 2028) periods for this time period variable to be incorrect as the structural break occurs at the start of the price control. We propose to work with Ofgem ahead of the Final Determination to ensure both the operational and statistical positioning is sensible.

The RIIO-ED2 price control period is one of greater uncertainty the RIIO-ED1 so we appreciate the balance that is required within modelling, and that despite this there will be a reduction in model quality. Our proposed corrections in response to this question and CORE-Q63 will improve the quality and robustness of the modelling from both an operational and statistical perspective.

We also note that the third totex model was only presented for the first time at DD, with Ofgem originally outlining the use of only two totex models at SSMD. Using untested totex models increases the risk of material errors and creates additional complexity. This is important in considering the robustness of the overall modelling suite, and the appropriateness of the catch-up efficiency targets. Please see CORE-Q110 for further details.

	Core-Q65.
Question	Do you agree with our proposed assessment approach for primary reinforcement?
Associated Evidence	
Title	**Link to evidence**
Annex 14 – Load EJP Addendums	n/a
North of Scotland Annex 10	n/a
Annex 4 – Ofgem Engagement	n/a
Response	

No, the proposed assessment for primary reinforcement is based on a material error of fact. Specifically, the use of a £/MVA metric for circuits and substation groups is erroneous as this does not account for the length of network, nor existing capacity. This approach puts rural networks with long circuits and low levels of demand at a disadvantage and will result in material under-funding. This issue is uniquely acute in the North of Scotland Licence Area (SHEPD) which is an outlier compared with other GB as shown in or North of Scotland Annex 10. The evidence, as outlined below, demonstrates that Ofgem's statement that "the cost of delivering one MVA of capacity from reinforcement to be comparable across DNOs" is an incorrect assumption, leading to material errors in the proposed assessment:

	Total Network Length km	Number of Customers	km per customer	**km Rank**	Peak Demand	**Demand Rank**
SSEH	52835	799061	0.0661	**1**	1748	**14**
SSES	80008	3166831	0.0253	**10**	8475	**1**
Median	**56070**	**2340629**	**0.0272**	**-**	**3983**	**-**

SEPD and SHEPD are at opposite ends of the scale in terms of customer numbers, network length and network-wide demand which highlights this issue because the calculated £/MVA is much lower (£87k) for SEPD than for SHEPD (£195k) – less than half (45%). With relatively consistent unit rates used by both licence areas, we have found the differences in £/MVA are attributable to differences in network characteristics, predominantly network length. This is further reinforced with RIIO-ED1 actual unit rate data also supporting this level of variance.

	Units	RIIO-ED2
SSEH	£'000/MVA	194.71
SSES	£'000/MVA	86.92
Median	**£'000/MVA**	**80.29**

SHEPD has more than double the network length per customer than all other DNOs and the lowest network wide peak demand. Due to the nature of rural Scottish terrain, it costs more to supply these customers than it does other areas of the UK. This does not suggest the cost is higher due to the size of conductors having to be bigger than the rest of the UK; rather, more conductors are required per customer and over challenging terrain. As it costs more to supply these customers, it will naturally cost more to reinforce the same customers following demand increases of LCT uptake.

SHEPD does not operate a 132kV network. This again puts SHEPD at a disadvantage as there is a greater opportunity to release more MVA per £ at higher voltage levels.

As a further point, we note that by using a single £/MVA released metric for Primary reinforcement there is an implicit assumption that the cost of flexibility services for releasing MVA capacity is the same across all DNO licence areas. We expect access to sufficiently competitive flexibility markets is likely to vary between DNOs and that this is likely to be a further factor driving differences in £/MVA costs.

Proposed alternative approach

We request that Ofgem reconsiders the use of £/MVA for circuits. To be consistent in approach to CV2 – Secondary reinforcement, SSEN is in favour of maintaining the £/MVA metric for substation reinforcement only as these are less subject to regional specific factors. It is also very difficult to develop a metric at substation level due to the variety of asset types and associated cost differences.

For circuits, or substation groups, we propose the use of a £/MVA/km metric. This will consider the benefits of releasing more MVA to the network and the higher cost in doing so whilst also accounting for length of the asset being reinforced. This metric would only penalise those DNOs who are delivering high costs per MVA/km of circuit length.

Simple alternative approach

Recognising the analytical and modelling challenges that may be associated with make this change, we propose that an alternative, and somewhat simpler, approach is to use the DNO-specific £/MVA released rate for SHEPD based on the ED1 and ED2 period average.

We agree that Other Reinforcement Activities should not be subject to benchmarking.

For our views on the LRE reopener, see our response to CORE-Q5.

We also note Ofgem's engineering comments on the EJPs associated with several our Primary reinforcement schemes and the associated 'partially justified' assessment. We have addressed Ofgem's concerns for each scheme via a cover sheet update to each of the EJPs in question as part of our Draft Determination response. We expect Ofgem to consider additional evidence provided in the EJP cover sheet updates as part of any further consideration of EJPs for final determination or as part of further modelling development. See Annex 14 for our load EJP addendums.

The link between Ofgem's EJP assessment and LRE Totex allowance in the DD is still unclear to us. As is how any subsequent change in status of EJP assessment might flow though to allowed revenues – as a result, for example, of an EJP moving from 'partially justified' status to 'justified' status through the provision of additional evidence to Ofgem. We note that this is inconsistent with the approach taken elsewhere, in Environmental for example, where there is a much clearer link between EJP assessment and proposed allowance.

We also note that LRE was not included as part of the letter from the Ofgem Engineering Hub – where we had hoped to see more clarity on the link between EJP assessment and allowances (*ref. Ofgem letter from Niall McDonald to Patrick Erwin dated 05 August 2022, Annex 4*)

Question ID	Core-Q66.
Question	Do you agree with the application of a volume adjustment based on the industry average ratio of forecast capacity added relative to the forecast demand growth above firm capacity? If not, what do you consider to be a better approach to assessing the efficiency of a DNO's proposed workload for primary network reinforcement?
Associated Evidence	
Title	**Link to Evidence**
Annex 8 - Environment	n/a
Response	

Yes, we agree with Ofgem's approach to calculate the LI adjustment using substation firm capacity relative to forecast demand growth.

We agree that care must be taken to ensure that this approach does not disincentivise, or otherwise penalise, oversizing of assets for strategic reasons – particularly where this can be shown to reduce the cost of capacity for customers in the long run.

Ofgem's business plan guidance is clear that proposals should include an amount of strategic investment[1] (Cat.2 expenditure) to ensure that future net zero pathways are not foreclosed. Our proposal includes an additional £23m to provide for this. We request that Ofgem ensures that its LI adjustment approach for Primary reinforcement is consistent with the objective of supporting the delivery of net zero at the lowest cost to customers, especially when peak demand is expected to continue to grow throughout ED3 and beyond.

Also, we encourage Ofgem to consider how its approach in this area supports investment in larger capacity assets for the purpose of reduction in technical losses and general alignment with net zero targets and ambition. Our response to Ofgem's questions on losses strategy is set out in CORE-Q88 and Annex 8.

1 *"Where the DNO is proposing investment deemed strategic in nature, this should be clearly identified within the load related investment plan. Such investment may be identified for the purpose of not foreclosing efficient future pathways…"* Ofgem, RIIO-ED2 Business Plan Guidance, September 2021 (https://www.ofgem.gov.uk/sites/default/files/2021-09/ED2%20Business%20Plan%20Guidance%20-%20September%202021_1.pdf

Question ID	Core-Q67.
Question	Do you agree with our proposed assessment approach for secondary reinforcement?
Associated Evidence	
Title	**Link to Evidence**
Annex 14 – Load EJP Addendums	n/a
Annex 7 - Deliverability	n/a
Response	

We agree with Ofgem's approach for secondary reinforcement with the exception of services. The use of LCT volumes rather than network-wide peak demand is welcomed and we agree with using the industry median unit cost split by sub-category.

We also acknowledge our allowances may change given our resubmission of LCT volumes. This resubmission is explained further in consultation question CORE-Q105.

For our views on the secondary reinforcement volume driver, see our response to CORE-Q4.

We also note Ofgem's engineering comments on the EJPs for HV and LV circuits and for HV/LV transformers and its assessment of 'partially justified'. We have addressed the concerns regarding deliverability of volumes in the DD response Deliverability Annex 7.

Ofgem's Business Plan Guidance is clear that proposals should include an amount of strategic investment[2] (Cat.2 expenditure) to ensure that future net zero pathways are not foreclosed. Whilst the UM Volume Driver ought to be able to efficiently fund additional secondary works, we anticipate the triggers, metrics and reporting will be designed for clear capacity need, rather than for funding strategic investment where the conventionally identified need may be less certain but where the potential cost to customers of not investing is much higher. This is the case for the proposed £23m future-proofing expenditure.

<u>Potential error in calculation of SSEN CV2 unit rates</u>

For both benchmarking purposes and to set the unit rates in the secondary volume driver component of the LRE UM, Ofgem has calculated unit rates for capacity released by GMT and PMT transformers. We believe there has been an error in this calculation, complicated by different interpretations of the CV2 BPDT.

Ofgem appears to have used the MVA associated with the units disposed, which is not an appropriate measure of MVA released. For SSEN (and what appears to also be the case for NPG) this number appears to have been incorrectly selected from rows 141 to 145 of CV2 – which is the capacity associated with constrained substations (not the capacity released). Other DNOs appear to state 'capacity added' in these same cells.

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2 *"Some load related investment may be identified to not foreclose efficient future pathways"* and *"Future proofing investments could be categorised as within ex ante allowances when there is adequate evidence"*, Ofgem – Load Related Expenditure Strategy Guidance', v5

SSEN transformer MVA capacity is detailed in rows 246-253 for PMTs, and 314-321 for GMTs. In these rows we have presented the capacity added (columns AA:AU) and also capacity removed, in terms of disposals (columns AW:BN).

We request that Ofgem confirms the use of these numbers in its modelling and benchmarking and reviews the basis for the unit rate calculations used for £/MVA released – including consistency of application across DNOs.

This is the subject of reverse SQ Load SQ4 'calculation of CV2 unit rates' (11/08/2022)

We also suggest this is a high-priority agenda item on the CAWG.

<u>Application of expert view unit costs</u>
In paragraph 7.145 of the core methodology document, Ofgem state: "For proactive service reinforcement, we use the expert view unit costs determined from the asset replacement assessment for the three asset sub-categories (LV Service (UG), LV Service (OHL), and Cut outs)"
We disagree with the application of this expert view. The expert view is, as stated, derived from the cost of works associated with asset replacement- but the driver in C2, CV2 and the load UM is load or connections related. This different driver does drive material differences in the activities undertaken, and therefore the costs, for example:

- New assets are more likely to require additional works due to wayleave / easement agreements
- Looped services will result in additional tracks and cabling compared to a single service supplying multiple properties

We received Ofgem's request for further data in relation to the LRE volume drivers- we suggest this would be a better source of an expert view for these unit costs.

Question ID	Core-Q68.
Question	Do you agree with the level of disaggregation and period of data used to calculate the unit costs listed in the table above for transformer reinforcement, circuit reinforcement and proactive service reinforcement?

Response

Yes, we agree with Ofgem's approach for disaggregation by asset category and are comfortable with the metrics used.

We accept that a £/km metric is appropriate for HV and LV cable circuits, and that this should be different to the £/MVA/km metric we propose for Primary reinforcement where the accurate assessment of MVA released is more readily available and where an MVA released component is an important cost driver.

We propose that a final decision on the period of data used should be taken once the apparent errors used in determining the £/MVA released (as set out in our response to CORE-Q67) have been addressed and corrected.

Question ID	Core-Q69.
Question	**Do you agree with our proposed assessment approach for fault level reinforcement?**
Response	
We largely agree with Ofgem's assessment approach for fault level reinforcement. However, Ofgem should provide *ex-ante* baseline allowances for specifically identified schemes where designs have been completed and where work is planned early in the ED2 period – especially where this addresses the high-confidence anticipation of high-risk fault level constraints. Our response to the specific volume adjustments proposed in DD for HV cables is provided in our response to CORE-Q70.	

Question ID	Core-Q70.
Question	Do you agree with our proposed adjustments to account for outlier volumes data for ENWL and SSES?
Response	

Our Business Plan submission included £51.4m in the South (SSES) for fault level driven reinforcement. This is for circuits and switchgear at all voltages (Primary and Secondary).

£20.8m of this is for HV (11kV) cable in SEPD (93 circuits). We accept an adjustment for HV cable. However, as a minimum Ofgem should fund for the work that is in train and due to be delivered in Year 1 of ED2 *ex ante* to help us ensure deliverability of the programme and pursue a sensible contracting policy.

The work planned for ED2 aims to cover those locations identified as highest risk (> 200% rating). This comprises four 11kV fault level schemes that have been in design since start of 2021 for delivery in Year 1 of ED2. These schemes will replace 12.8km of conductor and 3.2km of cable for a total cost of £2.4m.

We propose that work subsequently identified for ED2 years 2-5 is funded though the UM VD. We request that Ofgem ensures that the LRE UM VD is fit-for-purpose for fault-level driven (and voltage constraint-driven) works.

Question ID	Core-Q71.
Question	Do you agree with our proposed assessment approach for connections?
Response	
We largely agree with Ofgem’s assessment approach for Connections and appreciate that the use of MPANs or points of connection results in greater consistency across industry, and therefore a more robust view of an appropriate industry average unit cost. Please refer to Load CORE-Q5 Services & MPANs for corrected volumes of MPANs in C2 Connections tables of SEPD and SHEPD BPDTs. This was driven by our initial submission of MPAN volumes not including upgrades, which distorted some of Ofgem’s modelling.	

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Question ID	Core-Q72.
Question	Do you agree with our proposed assessment approach for NTTC expenditure?
Response	
No. During the Ofgem-led Uncertainty Mechanism Workshop on 19 May 2022 Ofgem was clear that Transmission Connection Point Charges (NTCC) for all DNOs would move to 'pass-through' treatment. This followed an email from Ofgem on 14 April 2022 seeking views on the definition and treatment of NTCC in ED2. SSEN responded to support NTCC being treated as a pass-through cost item. The DD also stated the NTCC would move to pass-through. Although subsequent clarification from Ofgem (email 11 July 2022) confirmed that this was an error and that NTCC will be included in totex allowances. Ofgem's DD position is unreasonable; these costs are highly uncertain and largely beyond the control of SSEN. We strongly believe that the best approach for customers is for the risk of this cost not to sit with SSEN as this would result in an unnecessarily high *ex-ante* TOTEX provision. This will also shield customers from the cost risks associated with forecasting errors. Ofgem should revert to its original approach for the treatment of NTCC as a pass-through cost item.	

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Question ID	Core-Q73.
Question	Do you agree with our proposed assessment approach on asset replacement?
Associated Evidence	
Title	**Link to Evidence**
Annex 4 – Ofgem Engagement	n/a
Annex 5 – Material Issues	n/a
Annex 7 - Deliverability	n/a
Annex 12 – Unit Rates	n/a
Annex 15 – Non-load EJP Addendums	n/a
Annex 10 – North of Scotland	n/a

Response

We strongly disagree with Ofgem proposed assessment approach on asset replacement. The approach Ofgem has taken diverts from the industry standard Common Network Asset Indices Methodology (CNAIM) which has been developed collaboratively by all GB DNOs and formally approved for use by Ofgem as the main tool to identify which NARMs asset require proactive intervention and as the foundations of the annual regulatory NARMs and Monetised Risk reporting. The following subsections set out the issues SSEN has identified with the volume assessment undertaken by Ofgem and the inputs used within the resultant Disaggregated Benchmarking:

<u>Our Network Asset Intervention Methodology (NAIM):</u>

As described within our A_7.1 Safe & Resilient Annex of our final business plan and within each of our NARMs related Engineering Justification Papers (EJPs) we have developed an updated **Network Asset Intervention Methodology (NAIM)** specifically for RIIO-ED2 which uses a **Health Score Intervention Criteria (HSIC)** to identify which assets most warrant proactive intervention during RIIO-ED2. The intention of this approach is to truly maximise the lifetime of our network assets whilst balancing the risk of failure.

We believe this detailed approach is a big step forward in best practice and the use of CNAIM and places us at the forefront of the industry. As a result, we have built a **£105m efficiency into our RIIO-ED2 CV7a and CV9 plans** when compared to the volumes that would be triggered by our CBRM models if we were to have looked more broadly at the wider Health Indices (e.g. all HI5s). **Currently, Ofgem's methodology for CV7 and CV9 does not account for this significant efficiency within the final allowances that are awarded.**

The **£105 million efficiency** is also directly reflected in how SSEN benchmark against the other DNOs in terms of the £'s spent for every Monetised Risk Point removed during RIIO-ED2 **(£/MRP)**. When subsea cables are excluded from the benchmarking, **SSENs NARM proposals deliver the 2nd and 3rd best £/MRP amongst all the DNOs.** This is the case despite having a significantly lower proportion of C4 assets on our network when compared with other DNOs, and therefore having less opportunity to minimise the £/MRP. We believe this demonstrates the efficiency of our proposed volumes and the value for money it represents for our network customers.

As such, Ofgem's cost assessment for CV7a/CV9 should be redesigned to take account of the efficiencies gained through the use of our NAIM and the resultant £/MRP we have committed to. The benefits of our industry leading approach should be **reflected proportionately within the cost assessment**, as explained below.

This could be appropriately reflected in the **unit costs** allowed for each DNO within the disaggregated modelling. A blend of Industry Median and the DNO proposed rates for RIIO-ED2 could be used which reflects where each DNO benchmarks on a £/MRP basis. DNOs which have built plans which deliver a more efficient £/MRP target should be given a heavier weighting towards their own proposed ED2 rates vs Industry Median, than DNOs which have built their plans to deliver a poorer £/MRP output. Not only does this reward DNOs which have proposed efficient NARM plans, but it reflects the fact that DNOs which have minimised their volumes by targeting solely high-risk assets have less opportunity to find unit cost efficiencies and actually meet the Industry Median. A qualitative assessment of the efficiency of each DNOs NARMs intervention plans could also be used instead of (or in addition) to the quantitative £/MRP benchmarking described above. Please see Annex 12 for additional information.

Use of Survivor Models:

Instead of accepting the outputs of our CBRM models and the application of our internal Network Asset Intervention Methodology (NAIM), Ofgem has opted to use inferior and outdated Survivor Modelling which considers the age of our assets only, making no use of the vast quantify of measured and observed condition data that is taken into account within our in-house CBRM models. By taking this approach Ofgem is effectively ignoring the industry approved Common Network Asset Indices Methodology (CNAIM), the vast condition data this is based on to identify assets requiring intervention and the concepts of the data commitments required for their Information Gathering Plan (IGP), and have stated that there is no relationship between the Disaggregation modelling to derive volumes and the volumes of assets which require a justified intervention which they have agreed to.

Ofgem has itself previously indicated that age alone is not sufficient justification for intervention, hence the development of the CNAIM methodology and the resultant CBRM models. For Ofgem to ignore the outputs of our CBRM models in favour of a far less sophisticated and historic outdated approach is a huge step backwards in the assessment of the efficiency of DNOs Asset Replacement plans and represents a significant risk to network customers in terms of network security and resilience.

This is represented in the frequency that Ofgem has chosen to ignore the outputs of its own Survivor Models and the inconsistency of its application. In many cases the Survivor Models produce asset replacement volumes far greater than the volumes we have produced using our superior CBRM models. However, in these cases Ofgem has not chosen to use the Survivor Model volumes and have accepted our own significantly lower volume. Ofgem's use of the Survivor Models also produces outcomes that are obviously illogical and unreasonable.

As an example, Ofgem's Survivor Models have calculated that we need to replace between 25,007 to 33,459 6.6/11kV poles in SHEPD. Despite this, Ofgem has accepted our much lower volume of 5,116. Conversely, in SEPD our own CBRM models have indicated that 16 132kV Circuit Breakers require replacement during ED2. However, Ofgem has opted to instead select the outputs of its Survivor Models and awarded a volume of only 0.6. Obviously, it is not possible for us to replace only 60% of a single circuit breaker. More fundamentally, it is not a reasonable of proportionate application of the methodology for Ofgem to use its in-house Survivor Models to make cuts to our CBRM volumes when the Survival Models calculate a lower volume, but then to ignore the outputs of the same Survivor Models when they result in a far greater volume than SSEN has proposed for other asset categories.

The results of the same Survivor Models have also been applied inconsistently across each DNO licensed area. SSEN is the only DNO that has seen cuts to its volume on the back of the Survivor Models and this has been applied inconsistently between SHEPD and SEPD. Meanwhile, the Survivor modelling has been used to award SP Distribution 36.4 33kV circuit breakers (33kV CB (Air Insulated Busbars) (ID) (GM)) despite not actually requesting any volumes for this asset category. We do not agree that this is in the best interest of network customers. Ofgem has not set out why the use of the Survivor Models was deemed to be appropriate in this context and the application of the Survivor Models results in a number of material errors.

Finally, in paragraph 7.207 of the core-methodology document Ofgem describes the approach it has used to calculate the average asset lifetimes. Ofgem concludes “We consider that all profiles offer valuable information and could not find sufficient objective reasons to choose one over the other, so we used all in our assessment.”. This approach is not reasonable or justified for various reasons. Firstly, an average asset lifetime should not be used to determine asset replacement volumes given that age alone is a very poor indication of the need to intervene on any asset. This is fundamental asset management basics, and this approach is both a historic and outdated methodology. Secondly, Ofgem’s methodology has produced several asset lifetimes that are clearly not correct. For example, the Survival Model Profiles calculate an average lifetime of 82.1 years, 100 years, 113.3 years, and 121.5 years for LV Services (UG). Ofgem has then chosen the Profile which uses an average lifetime of 121.5 years to assign the SEPD volumes within the disaggregated benchmarking. There appears to be no clear criteria that has informed this selection and an average lifetime has been chosen which is clearly not appropriate. Ofgem appears to have inconsistently chosen the Profile which seems least wrong across 6 options when using the models as the chosen volume within the disaggregated benchmarking. The Profile chosen varies from asset category to asset category undermining the credibility of each of the Profiles.

Run Rate Analysis

In a number of instances, Ofgem has chosen to use a Run Rate volume within its Disaggregated benchmarking, in some cases in favour of our CBRM calculated volumes. Again, we strongly disagree with this approach. Often this is the case where the corresponding EJP is not considered to be fully justified by Ofgem due to perceived issues with the deliverability of the proposed volumes. As explained below, this will have the effect of disallowing a very significant proportion of the proposed volumes where the needs case is accepted, which is not in the interests of existing and future consumers.

The Run Rate volume has been used by Ofgem in a number of cases to deviate significantly from our proposed volumes even when the corresponding EJPs are ‘Partially Justified’ but the engineering needs case for the full volume is considered justified. **For example,** Ofgem has selected a volume of 5.6km for the overlay of end-of-life LV underground cable in SHEPD (which would mean it would take **10,569 years** to replace our existing LV cable network if this rate were to be maintained). This is equal to a 97% reduction in the volumes we initially proposed (164km). However, during the Cost & Engineering Bilateral held on the 28th July 2022 (full details in Annex 4), Ofgem indicated that it broadly agrees with the needs case for the volumes we have proposed, and its only concern was deliverability. With this in mind, we believe the scale of the 97% reduction in volume used within the disaggregated modelling is **entirely unreasonable and disproportionate and does not protect network customers** from the under investment in critical network infrastructure which, if properly funded, will act as a key enabler of Net Zero.

As such, we would ask that Ofgem considers the scale of the cuts made on the premise of Deliverability only, where the needs case for the proposed volumes is strong to ensure these cuts are reasonable and proportionate. In doing so it is critical to carefully consider the consequences for existing and future network customers of not delivering any volumes with a strong engineering needs case, given that end-of-life assets will fail regardless of whether their replacement is perceived to be deliverable or not.

Finally, it is also unclear why Ofgem has opted to select 'ED1 Performance' on occasion rather than the 'Run Rate' volume when the corresponding EJPs have been deemed 'Partially Justified' on the premise of Deliverability. For example, in SEPD our 33kV Fittings volumes have been cut from the proposed volume of 113 to the ED1 Performance volume of 67.5 because of Deliverability. However, the Run Rate volume is calculated to be 193.9 indicated that our proposed volume is in fact deliverable.

Assessment of CV7/CV8/CV9 Deliverability

As described above, in a number of instances Ofgem has not accepted our proposed volumes due to perceived deliverability concerns. SSEN has provided additional information to further evidence the deliverability of our proposed volumes (see Annex 7), but notes that Ofgem has not provided any information to explain why its believes our proposed volumes are not deliverable other than pointing to the fact that on occasions individual asset categories happen to be greater than our ED1 average, and sometimes only fractionally so. We believe that this evidence-based strategy meets the minimum requirements set out by Ofgem to justify our proposed delivery across numerous asset categories

We also have serious concerns with how Ofgem has responded to EJPs that have been classified as 'partially justified' due to concerns with deliverability. On several occasions Ofgem has accepted the needs case for condition related intervention but has applied significant cuts to the proposed volumes because of the perceived deliverability concerns on our ability to deliver when compared to our achieved volumes in the RIIO-ED1 period without acknowledging these are completely different programmes of work with different drivers and targets for RIIO-ED2. We believe that these cuts have been applied entirely disproportionally to the underlying concerns with the EJP and do not protect existing and future network customers from the resultant massive under investment in critical network infrastructure that will, if properly funded, be a key enabler of net zero.

For example, Ofgem has accepted the need for a significant step change on our LV underground cable overlay volumes in RIIO-ED2 given the evidence that we have presented. In the Cost & Engineering Bilateral held on 28th July 2022 (full details in Annex 4), Ofgem indicated its agreement with the need to overlay the volumes we have proposed and made it clear that the cable EJPs were almost entirely justified if a little more evidence was presented on the deliverability of the proposed volumes. However, despite this Ofgem has cut our proposed volumes for SHEPD from 164km to only 5.6km, **a cut of 97%.** We believe this approach is **entirely unreasonable and disproportionate** and is definitely not in the interest of existing and future network customers who will become ever more reliant on the LV network as they adoption of electric vehicles and heat pumps continues to accelerate.

These deliverability cuts are also made to activities which are predominantly outsourced by DNOs (such as cable overlay). Consequently, these are areas where additional external resource can be readily secured if early notice of these increased volumes is shared with the supply chain in advance (as has been carried out by SSEN). It is therefore irrational that huge cuts have been applied in these circumstances despite agreement that the intervention itself is required and fully justified and given the ability to ensure deliverability through additional external resource if needed.

Next, in the assessment of deliverability Ofgem does not appear to have considered the following factors, each of which is important when assessing the deliverability of our proposed volumes:

- **Identification of volumes by Switchboard** - Ofgem has selected a volume of 0.6 132kV circuit breakers rather than the 16 we have proposed. This alternative volume has been selected because the volume of 16 is an increase from the 12 replaced during ED1. Notwithstanding that impossibility of replacing 0.6 of a circuit breaker, Ofgem's assessment of the deliverability of our plan does not consider that 10 of the 16 circuit breakers are in fact part of a single switchboard and must be replaced collectively as part of a single project, as highlighted within the supplementary evidence we provided during the SQ process. Collectively we only plan to intervene in 2 substations in ED2 compared to 3 in ED1. The scale of the increase in volume from ED1 to ED2 is also very minor and easily deliverable within a 5-year price control. As such, Ofgem must review the number of switchboards our volumes represent, whilst also reviewing the significance of the increase proposed between price controls.

- **A holistic view of the entire CV7/CV9 proposals** - In many cases we have proposed volumes significantly lower than RIIO-ED1 for individual asset categories. The reduction in these asset categories frees up resource to deliver the volumes associated with asset categories that have increased when compared to ED1, especially where the asset categories are closely aligned in type. As such, Ofgem must take a holistic view of our NARM volumes before determining if any of the volumes proposed for each individual asset category are undeliverable.

- **Consequences of under delivery due to Deliverability** – In Ofgem's alternative proposed volumes they have not considered the consequences for existing and future network customers if end-of-life assets are not replaced where SSEN has provided clear data proving their poor condition. In many cases, not intervening proactively is choosing to respond reactively to failure instead which is generally far more expensive and more difficult to resource. Unfortunately, end-of-life assets will not wait to fail for a time that Ofgem deems to be deliverable for SSEN. These assets will fail regardless and SSEN has no option but to respond to these failures. As such, it is much more efficient for existing and future network customers for this intervention to be scheduled proactively. As such, when selecting an alternative volume, Ofgem should select a volume which adequately protects network customers from under investment in critical network infrastructure, rather than the lowest of all historic volumes.

More fundamentally, it is important to recognise that SSEN's network was not historically built at a constant rate in previous decades. Often, assets were added to the network in large peaks and troughs over time. As a result, it is natural to expect that the subsequent asset replacement will also come in waves. This is reflected in the variances between our ED1 actuals and our ED2 forecasted volumes where some individual asset categories have seen increases and many have seen decreases. As such, a variance to the ED1 run rate is not reason by itself to challenge the justification of our proposed volumes particularly where our volumes are complemented by real condition data down to the individual assets. Often a step change in volumes in specific areas is in the best interest of network customers and DNOs should be challenged to deliver this step change rather than being assigned a standard Run Rate volume only.

Inspection Frequency of NARMs assets

Each DNO has a responsibility to determine the optimal frequency with which each of its assets are inspected and maintained. These cycles (which are built into SSEN policy, namely TG-NET-ENG-006) consider several requirements including the manufacturers recommended inspection/maintenance timescales, the total volume of assets in each asset category, and the optimisation of our totex plan.

As an example, we have approximately 927,000 individual poles on our network (472,000 SHEPD, 454,000 SEPD). We inspect each pole on a 1-in-8-year cycle. This gives an approximate annual inspection volume of 121,500 per year. Whilst in an ideal world we would like to inspect our poles every year, this is clearly not practical given the sheer volume of poles we have on the network. Inspecting our poles more frequently would drive a large increase in the opex costs associated with managing this asset category which would not be reflected proportionally in any improvement in capex spend. Effectively, we believe we have already optimised our inspection cycle and any changes to its frequency would not be in the interest of our network customers.

However, within the Disaggregated modelling Ofgem has applied cuts to our volumes in key areas on the premise that these assets have not been inspected frequently enough and therefore the outputs of our CBRM models cannot be trusted. Examples of the EJP feedback include:

6.6/11kV OHL Poles EJP*: "It was confirmed that only assets that have recent inspection data have been considered for intervention and that assets without data are capped at HI3 and hence not considered. Clarifications indicates that <20% of this asset base are inspected annually. With less than 20% of this asset base inspected annually this introduces a risk related to the proposed volume. It should also be noted that if there is a change to the health and safety regulations for creosote, this could change the cost and life (hence volumes) of future wooden poles replacements. We therefore consider the EJP to be partially justified."*

This conclusion is incorrect for the following reasons:

- Only assets that have been inspected and condition data collected will have Health Scores that fall into our Health Score Intervention Criteria (HSIC). Therefore, additional inspection would only increase the number of poles shortlisted for intervention and should not be used as justification for applying cuts to these CBRM calculated volumes.
- It is SSEN's responsibility to determine the appropriate inspection and maintenance frequency for our network assets. It does not fall within Ofgem's regulatory remit to

determine how frequently SSEN should inspect its assets, or to challenge the intervention volumes that are required as a result of the data collected from these inspections and fed through our CBRM models. As described above our 1-in-8-year cycle for poles is an established SSEN policy that we intend to continue to work to.

- Any new safety regulations on the use of creosote would only impact the unit cost to install new poles (drive a higher unit cost). It would not impact RIIO-ED2 volumes given that the alternative non-creosote poles used during RIIO-ED2 would not be scheduled for replacement themselves for approximately another 50-60 years, so their own lifetime is irrelevant for RIIO-ED2. This environmental policy change would only impact RIIO-ED2 volumes if the alternative pole type used were to last for less than one price control period and this would only then represent an increase in our volumes, not a decrease.
- Ofgem has not reflected its view that poles should be inspected more frequently in the CV30 Inspections cost assessment where additional cuts have been made preventing us from inspecting our poles at the increased frequency suggested.

CV7 Unit Cost Assessment:

We note that Ofgem has opted to apply a mix of ED1 derived expert unit rate, ED1 actual and ED1 & ED2 forecast rates of all CV7 asset categories. We agree with this approach **only where** there is no DNO specific reason provided which explains the difference between their proposed cost and this assessed rate. However, SSEN has proposed unit costs for several asset categories that are higher than the assessed rate for specific and legitimate reasons.

For example, we proposed a higher blended unit cost for the 6.6/11kV Transformer (GM) asset category which reflects the higher material costs associated with the innovative LV On load Tap Changer (LV OLTC). This technology is designed to reduce the consumption of our customer's home appliances by conditioning the voltage supplied by the LV network. The benefits associated with this functionality are greater now given the ongoing cost of living crisis and the need to protect vulnerable and fuel poor customers. The same incremental cost has been awarded to ENWL through their Smart Street CVP, however in this example Ofgem have only allowed SSEN the industry mean CV7a unit cost for this asset category which effectively prevents us from deploying this more expensive technology, to the detriment of our network customers.

There are several other examples of CV7a unit costs that have been calculated specifically to account for uniqueness in our RIIO-ED2 submission compared to the other DNOs. These include LV (OHL) Mains Conductor, LV UG cable, 6.6/11kV UG Cable amongst others. The other unit costs where SSEN has specific and unique drivers of a higher unit cost are documented within Annex 12.

Where SSEN has provided clear reasons and evidence to explain why we require a higher unit cost for specific asset categories we suggest that Ofgem excludes these from the calculation of the Industry Median so as not to influence the calculation for others and award SSEN our proposed unit costs which are specific to our RIIO-ED2 plans.

Within Annex 12 we have also provided our views on how the efficiency of each DNO's NARMs intervention plans should be reflected within the unit costs that are awarded. As discussed, within Annex 12 our approach has delivered efficiencies in the region of £105m which we believe should be reflected in the unit costs we are awarded.

Assessment Approach for Subsea Cables (CV7 & CV25)

The approach taken by Ofgem to assess the subsea cables proposed under CV7 & CV25 was not clear prior to the Ofgem's response to SSEN's Supplementary Question SSEN 030 (Subsea Cable Investment) dated 15th Aug '22. The disaggregation of totex allowances, modelling of Company Specific Factors (CSF) and acceptance of SSEN specific CSF remains a concern. Further challenge is included within Annex 5 – Modelling Errors and additional CSF justification and EJP justification provided within Annex 10 – North of Scotland.

SSEN disagrees with the approach taken on the following (further details can be found in our North of Scotland Annex 10):

- The normalisation for Company Specific Factors is lower than our submitted figure (£34m normalised v £45m submitted) leaving an element within the CV disaggregated suite to be assessed.
- The normalisation is applied across all NARMs assets equally and not specifically subsea cables.

All subsea cables should be removed from the standard modelling suite and assessed independently. Further subsea cable cost modelling observations have been highlighted in CORE-Q63 (Normalisation) & North of Scotland Annex 10.

The assessed subsea Unit Rates within CV7 are based 50% on RIIO-ED1 expert rates, which did not include elements such as protection and increased stability provisions and were granted as an in-Price Control re-opener. Unit Rates should be assessed using the latest information provided by SSEN within our RIIO-ED2 baseline plan. Subsea cable replacement project delivery costs are significantly different now compared to the RIIO-ED1 Price Control. The three new unit rates proposed for the subsea cable proactive replacement projects (based on cable length) have been structured around RIIO-ED1 actual project delivery costs.

Similarly, in HVPs (CV25), a single project (Skye to South Uist) was proposed with a given volume and cost. The Ofgem Engineer Hub assessed the EJP as 'Unjustified' and therefore no volume was awarded, yet a cost of £14.03m awarded. This approach is not feasible or practical in terms of Ofgem RIIO-ED2 cost and volume deliverables.

No split is provided in the DD Models between HV and EHV Cables for CV7, and so in determining the link between Ofgem's cost and engineering assessment has been impossible. We have been unable to identify the link between the Engineering Hub assessment of EJPs and the treatment of such by the Cost Assessment team. There does not appear to be continuity between justified volumes and DD allowances.

We require Ofgem to provide us with a full explanation at the Final Determination of the allowed baseline costs in CV7 and CV25 for subsea cables split between HV and EHV and to show clearly how the engineering assessment links to the cost modelling process. This should consider all our feedback and additional evidence on company specific factor modelling adjustments and engineering justification papers. We consider that with this Ofgem will be able to approve in full our CV7 and CV25 costs for asset replacement in full, as per the April'22 re-submission. We are happy to support Ofgem with assessing these costs ahead of the final Determination.

Moreover, there appears to be no recognition of our 29th April 2022 re-submission for subsea cables. This point is acknowledged by Ofgem in their response to our reverse SQ SSEN030. Within the RIIO-ED2 Final Determinations the following cables should not be included within the baseline:

1. Skye – Uist (North route)
2. Pentland Firth West
3. Mainland Orkney – Hoy South (3)
4. Eriskay – Barra 2
5. South Uist – Eriskay

Each of the above cables were removed from our RIIO-ED2 ex-ante baseline through the 29th April re-submission, and it was our stated intention that these cables would be subject to the Hebrides and Orkney Whole System (HOWS) assessment. We request Ofgem voids any Engineering Review Assessment or comments applied at the Draft Determinations.

Question ID	Core-Q74.
Question	Do you agree with our assessment approach to refurbishment?

Response

We agree with the proposed description within the core methodology document for CV8 and CV9. However, we do not agree with Ofgem's application of their stated methodology within their workings, and we have noticed a number of mistakes within the disaggregated models that are not consistent with the methodology that has been described.

We also do not agree with the use of survivor models for the reasons set out in response to CORE-Q73 but have noted that the volumes calculated using these models have not been used directly in the disaggregated modelling. It is also not clear how Ofgem has selected their alternative volumes within the disaggregated modelling where our proposed volumes have not been accepted.

Furthermore, as per the reverse supplementary questions we submitted on this topic we believe we have noticed a number of errors within the disaggregated modelling for CV8 and CV9. These are listed below:

- No volumes or unit cost assigned to CV9 (33kV Transformers (GM)) despite the EJP being fully justified. We consider this to be an error as we have submitted volumes for the refurbishment (CV9) of both 33kV and 132kV Transformers (GM). This was subsequently confirmed by Ofgem in response to reverse SQ SSEN035.

- Ofgem also provides no costs for 132kV and 33kV oil-filled cable in CV9 again where we have a justified EJP and submitted volumes (SEPD - 33kV 40km, 66kV 5km, 132kV 18km, SHEPD - 0km).

- The Ofgem proposed CV9 unit cost for Tower refurbishment is higher for a 33kV Tower than it provides for 132kV towers. A 132kV Tower is much larger than a 33kV Tower these costs should be directly reflected in the refurbishment unit cost.

  132kV Tower – SEPD Proposed: £18.4k, Ofgem Chosen Unit Cost: £7.7k
  33kV Tower – SEPD Proposed: £4.8k, Ofgem Chosen Unit Cost: £10k

- There is an error in CV8 where no unit cost is provided for 'Protection', but volume is allowed. This is obviously an error and is wrong. This was identified and confirmed at our bilateral

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q75.
Question	**Do you agree with our proposed assessment approach for asset replacement driven civil works?**
Response	
Yes, we agree with Ofgem's proposed approach for asset replacement driven civil works.	

Question ID	Core-Q76.
Question	Do you agree with our proposed assessment approach for Condition Based Civil Works?
Response	
Yes, we agree with Ofgem's proposed approach for Condition Based Civil Works.	

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q77.
Question	**Do you agree with our proposed assessment approach for diversions?**
Response	

We agree with Ofgem's decision to accept the forecasted volumes submitted by each DNO in the CV5 baseline. However, we fundamentally disagree with Ofgem's decision to reject SSEN's Uncertainty Mechanism (UM) that we have proposed for Diversions. Our response to the Ofgem rejecting our proposed UM is covered in more detail within RIIO-ED2 Draft Determinations SSEN Annex, SSEN-Q8.

Network diversions are driven entirely by landowners who wish to either divert network assets from their land to facilitate their own developments or to maximise the revenue they receive from the assets on their land. SSEN has no control over the number of Diversions that are requested and must be funded appropriately to facilitate this landowner driven work in good faith without imposing unreasonable delays in an attempt to manage an insufficient budget.

It is not possible for any DNO to accurately predict the volume of Diversions that will be triggered by network customers during RIIO-ED2 or the costs of these diversions given that each project can significantly vary in cost, particularly at the higher voltage levels. This uncertainty in cost is reflected in some of our most recent 132kV Diversions where single diversions have cost significantly more than the average unit cost.

Consequently, we made the decision to split our forecasted volumes across both the baseline CV5 ask and an UM. We believe this is in the best interest of network customers. If the UM is rejected the full RIIO-ED2 volume forecast must be reapplied into the CV5 baseline to be consistent with the methodology Ofgem has used to appraising other DNO's CV5 volumes.

Currently, Ofgem has not added the volumes associated with our UM back into the baseline when carrying out the disaggregated modelling. However, it appears that in rejecting ENWL's Diversions UM, Ofgem have added the UM volumes back into the CV5 baseline volumes used within the disaggregated modelling. However, unlike ENWL, the volumes associated with SSEN's rejected Diversions UM have not been included within the disaggregated modelling. We believe that this drives an inconsistent and unfair approach to the Disaggregated assessment if Ofgem continues to reject our proposed UM.

However, in response to our reverse SQ SSEN042 Ofgem told us that "ENWL's baseline Diversions costs and volumes were not increased because of the rejection of their uncertainty mechanism proposal". However, Ofgem has not explained why the volumes used for ENWL in the disaggregated modelling is higher than the volumes submitted within their final BPDTs. We have also not received any information from Ofgem which would indicate that DNOs who have split their forecast between the baseline and a UM should resubmit volumes into their baseline to enable the disaggregated benchmarking and the DNO comparison.

The image below shows the CV5 Diversions volumes submitted by all DNOs in their final BPDTs and compares this with the volumes used in the disaggregated benchmarking. As seen, the volumes used for ENWL have been increased. Ofgem have not explained why this has occurred despite a request for this information:

Diversions (non-fully rechargeable)		[redacted]
Conversion of wayleaves to easements, easements, injurious affection		
Conversion of wayleaves to easements, easements, injurious affection	LV	
Conversion of wayleaves to easements, easements, injurious affection	HV	
Conversion of wayleaves to easements, easements, injurious affection	EHV	
Conversion of wayleaves to easements, easements, injurious affection	132kV	
Total		
Diversions due to wayleave terminations		
Diversions due to wayleave terminations	LV	
Diversions due to wayleave terminations	HV	
Diversions due to wayleave terminations	EHV	
Diversions due to wayleave terminations	132kV	
Total		
Diversions (non-fully rechargeable)		
Conversion of wayleaves to easements, easements, injurious affection		
Conversion of wayleaves to easements, easements, injurious affection	LV	
Conversion of wayleaves to easements, easements, injurious affection	HV	
Conversion of wayleaves to easements, easements, injurious affection	EHV	
Conversion of wayleaves to easements, easements, injurious affection	132kV	
Total		
Diversions due to wayleave terminations		
Diversions due to wayleave terminations	LV	
Diversions due to wayleave terminations	HV	
Diversions due to wayleave terminations	EHV	
Diversions due to wayleave terminations	132kV	
Total		

In addition, within section 7.78 of the core methodology document Ofgem have explained that they have reclassified the M13 costs associated with ENWL's Diversions UM into the baseline ask:

"ENWL: [redacted] *of forecast cost for LRE uncertainty mechanisms and* [redacted] *of forecast costs for diversions, tree cutting (ash dieback) and environmental reporting (PCBs)"*

It is unclear why these costs have been reclassified for ENWL, but the same costs have not been reclassified for SSEN given that our own forecasted cost and volumes have also been split between a baseline ask and the proposed uncertainty mechanisms. **For the avoidance of doubt**, our baseline costs/volumes are those we have certainty on, whereas the UM costs are those we cannot guarantee given the uncertain natures of these activities. However, both the baseline and UM together make up our forecasted cost/volumes. As with ENWL, if Ofgem continue to reject the proposed UMs we would require the costs associated with these to be reallocated to the baseline. However, before doing so we would ask for further engagement with Ofgem to agree what costs are appropriate to add into the baseline given the risks associated with these uncertain forecasts.

As such, we would ask that if Ofgem continue to reject our proposed UM at Final Determinations, the full costs and volumes associated with this UM must be added into the baseline ask as they have been for ENWL. See figures below for SHEPD and SEPD respectively, and a re-submission of Business Plan Data Tables required.

Furthermore, within Ofgem's UM feedback they state:

"We also want to ensure that DNOs are incentivised to minimise diversions costs, and we consider ex ante funding to be the best approach to do this"

However, we disagree with this premise. Where our assets have been built on land with unsecure land rights our customers are legally entitled to request that the assets on their land are diverted. If Ofgem wishes to minimise diversion costs it is not appropriate for them to do so by limiting the funding available to DNOs to respond in good faith to these legitimate customer requests. This will only worsen the relationship between DNOs and Landowners and make it more difficult for DNOs to pursue secure land rights for future network developments. Instead Ofgem should look to minimise future Diversion costs by introducing improved land rights so that DNOs can better secure their network assets.

As such, Ofgem and BEIS should review the current arrangements for wayleaves diversions and land access and ensure that DNOs have sufficient powers to be able to develop the network rapidly required and ensure that landowners are not able to extract unreasonable fees, ultimately from bill payers.

We have well established processes in place to manage requests from the landowners to minimise the disruption and costs and of Diversions to our network customers. These processes have reduced claims by 66% through negotiation. The negotiated value saved against initial worse case network impacts has achieved saving in excess [redacted]. We would continue to operate, as we have an Uncertainty Mechanism in place to limit any funding that could impact consumer bills.

SHEPD

Wayleaves and Diversions

C/CV sheet cost would be reported in	Cost category or Asset class within sheet	Cost line / name	Sub-category 1	Sub-cate	Voltage	Units
CV5 - Diversions	Diversions due to wayleave terminations				LV	Diversions completed
CV5 - Diversions	Diversions due to wayleave terminations				HV	Diversions completed
CV5 - Diversions	Diversions due to wayleave terminations				EHV	Diversions completed
CV5 - Diversions	Diversions for highways (funded as detailed in NRSWA)				LV	Diversions completed
CV5 - Diversions	Diversions for highways (funded as detailed in NRSWA)				HV	Diversions completed
CV5 - Diversions	Diversions for highways (funded as detailed in NRSWA)				EHV	Diversions completed
Total						

[redacted]

SEPD

Wayleaves and Diversions

C/CV sheet cost would be reported in	Cost category or Asset class within	Cost line / name	Sub-category 1	Sub-category	Voltage	Units
CV5 - Diversions	Diversions due to wayleave terminations				LV	Diversions completed
CV5 - Diversions	Diversions due to wayleave terminations				HV	Diversions completed
CV5 - Diversions	Diversions due to wayleave terminations				EHV	Diversions completed
CV5 - Diversions	Diversions due to wayleave terminations				132kV	Diversions completed
CV5 - Diversions	Diversions for highways (funded as detailed in NRSWA)				LV	Diversions completed
CV5 - Diversions	Diversions for highways (funded as detailed in NRSWA)				HV	Diversions completed
Total						

[redacted]

Question ID	Core-Q78.
Question	Do you agree with our proposed approach for Rail Diversions?
Response	
We agree with Ofgem's position on Rail Diversions to set nil *ex ante* allowances and retain the RIIO-ED1 re-opener mechanism for rail diversions for RIIO-ED2.	

Question ID	Core-Q79.
Question	Do you agree with our proposed approach to assessing Non-Operational, Operational and Business Support IT&T costs?
Associated Evidence	
Title	**Link to Evidence**
Annex 16 – IT EJPs	n/a
Annex 17 – OT EJPs	n/a
Annex 18 - Cybersecurity	n/a
Response	

For Information Technologies and Telecommunications (IT&T), **we materially disagree with the cost assessment methodology** for the following reasons:

1. Ofgem has departed from its previous RIIO-ED1 approach without additional justification being provided: IT&T has been assessed at licensee level in ED2 as opposed to company-level which was the RIIO-ED1 methodology. A licensee-level assessment is not reasonable in the context of IT&T, as it is not representative of how we operate our IT systems from a cost perspective. Therefore, these costs must be assessed at company level in line with the approach taken in RIIO-ED1.

2. In addition, IT&T has been assessed across the ED1 & ED2 periods combined, despite ED2 presenting additional unique and well-recognised challenges, in particular in the shape of the scale of change and digitalisation required to meet net zero obligations and changing customer expectations. These challenges are not accounted for via any pre-modelling adjustments. The period of assessment for IT&T should only be ED2 to reflect the scale of change in requirements.

3. IT&T Qualitative adjustments resulting from the assessment of Engineering Justification Papers (EJPs) are made after cost modelling, with the assessed ratio analysis performance applied to the EJP adjustment. Qualitative adjustments should be made before the disaggregated cost assessment to ensure fair comparison across DNOs in cost modelling. Furthermore, due to issues with the use of MEAV as a driver in the quantitative modelling we would suggest Ofgem utilise a mix of Qualitative and Quantitative modelling as with the RIIO-ED1 approach, which utilised a 75% qualitative and 25% quantitative approach. The MEAV driver used in the quantitative modelling approach is not strongly statistically nor operationally linked to the expenditure.

4. Moving Cyber Security costs out of the baseline and into a reopener despite clear recognition from Ofgem that they agree with the needs case and justification we provided is unjustified. It unnecessarily increases the workload on DNOs and Ofgem in-period, risks delaying key investment and sends the wrong message on committing to security projects. This is addressed further in our confidential response on cyber security.

To further demonstrate point 2 above, the electricity sector will face more change in ED2 than it has in decades, with the further development of our DSO roles and responsibilities, and a strong, necessary focus on Data and Digitalisation, one of the foundations in achieving net zero. This is acknowledged in a number of places including section 4 and 7 of Ofgem's Core Methodology document, and also refers to the BEIS Smart Systems and Flexibility Plan 2021. This change is underpinned by IT&T, and requires many new systems, data, controls, and monitoring. The new systems are required to enable market facilitation, forecasting, coordination and management, and new contract and payment systems are also required to implement our key DSO functions. They support the wider digitalisation of the electricity grid, the roll out of monitoring and control systems to help facilitate more low carbon technology on to our network, particularly at LV, and support our customers' net zero goals. This will be a significant uplift on current customer expectations.

We note that Ofgem's DDs also include significant new reporting requirements which were not part of our submission but will need to be underpinned by foundational IT systems. This includes details of our digital estate via Technology Business Management (TBM), modernisation of regulatory reporting and the suite of new DSO metrics. We are also required to comply with new licence obligations relating to digitalisation and data best practice.

It is therefore critical that we are appropriately funded to meet all new obligations and requirements that are placed on us, and that we are able to act as an enabler to net zero. Ofgem's current approach to assessing IT&T costs is unreasonable in that it is not aligned with or reflective of the step-change required in ED2. Moreover, any reduction in our IT programme will have significant impacts on other areas of our Business Plan, as it will reduce the capabilities of those IT platforms, and this will negatively impact the benefits.

To outline more detail on point 3 above on the EJPs, six EJPs in the IT area were classified by Ofgem as unjustified. Ofgem considers that additional information is required on these in relation to deliverability, benefit realisation and resourcing as key themes. While much of the information required was originally provided in our business plan and through the SQ process, we have consolidated it, along with any additional evidence into a single document, Annex 16, that clearly addresses the questions raised. Sixteen of the EJPs were deemed by Ofgem to be partially justified, in that the scope of the deliverables was justified, but there were concerns over deliverability. We have set out more details about the deliverability of these projects in the same document, Annex 16. While we recognise that deliverability, in particular the need for more skilled resources and supply chain constraints, creates a significant challenge to achieving net zero globally, our robust and detailed strategy and plan will adequately address this risk. The document sets out our approach to ramping up resourcing through recruitment, training, and increased use of our existing supplier partners. It also sets out our approach to benefits realisation through business ownership. Due to the nature of ED2 IT deliverables we will increase our use of Agile methodologies. Interdependencies between workstreams will be resolved through portfolio level management. Note that the responses to all questions do not alter any aspects of the scope, cost, or benefits of the projects, but just provide the additional details required to demonstrate deliverability, benefit realisation and resourcing. In addition, the deliverability of the IT&T programme would be compromised if not fully funded, resulting in the need to reprioritise and descope elements with impacts on other areas of the plan and ultimately our customers.

In the OT area, various qualitative adjustments are also applied in the DDs. We consider that the qualitative assessments are not justified by the evidence we have submitted. As the reasons vary across different EJPs, we have provided additional evidence in support of our EJPs in a single document for OT in Annex 17. Additional information on Excess Construction Charges is provided in relation to our EJPs for Personnel Communication Resilience and the OTN Rollout. This is intended to provide confidence in our cost assessments.

We acknowledge that certain Substation Scada works were included in our ED1 business plan and have been included again in our ED2 business plan. However, we note that a number of factors in ED1 resulted in a change in priorities and deprioritising the Substation Scada works. These are outlined in Annex A5.1 of our final business plan[3] and include responding to changing customer needs and dealing with regulatory changes including changes in GDPR and cyber-security requirements. ED1 operates on the basis of a totex approach, which allows companies to make decisions and trade-offs within their overall totex allowance. We note that we are in overall overspend position in ED1, so we would not have benefited financially from the decision to deprioritise Substation Scada works in ED1, and there is no risk of double funding for ED1. In RIIO-ED1 we proposed a like for like replacement of RTUs. During ED1, it became apparent that this approach would see many sites needing both an RTU and an ANM controller. By re-engineering our approach to RTUs, we can now combine this functionality and provide enduring efficiencies.

Adequate funding for IT&T Business Support costs is crucial for RIIO-ED2 to enable investment to meet the step change in both Data and Digital requirements, DSO and our overall IT/OT programme as described above.
Whilst we agree with assessing IT & Telecoms BSC together with Operational and Non Operational IT Capex as per points 1 and 2 above (and CQ103) our position is that this area should be assessed at company level and using RIIO-ED2 data only, particularly given that Ofgem accepts in the Core Methodology that this area has "*a high level of fixed costs. Moreover, these costs are expected to increase substantially over RIIO-ED2".*
For SHEPD we disagree with the Draft Determination for our Company Specific Factors which impact our IT&T BSC Spend (Sparsity and Islands)– please refer to our North of Scotland Annex and resubmitted M25.

[3] https://ssenfuture.co.uk/wp-content/uploads/2021/12/A_5.1_DigitilisationStrategy_CLEANFINAL_REDACTED.pdf

Question ID	Core-Q80.
Question	Do you agree with our proposed assessment approach for Legal and Safety?
Response	
Yes, we agree with the proposed assessment approach for Legal and Safety.	

Question ID	Core-Q81.
Question	Do you agree with our approach to assessing Overhead Line Clearance costs?
Associated Evidence	
Title	**Link to Evidence**
Annex 5 – Material Issues	n/a
Annex 15 – Non-load EJP Addendums	n/a
OHL Clearance CV18 BPDT Update	n/a
Response	

We agree with the proposed methodology; however, our assessment of the disaggregated model confirms that the stated methodology has not been applied. As such, we disagree with the Draft Determination position on the proposed unit rates.

Ofgem stated in the Core Methodology Section 7.272 "we propose to use RIIO-ED1 and RIIO-ED2 data to set efficient unit costs at the industry median for each voltage." From our assessment of the Disaggregated Model it appears as though the unit rate applied is based on a total cost view assessment level rather than sub-category voltage level unit rate assessment. This contradicts Ofgem's statement made within the Core Methodology.

We believe that assessing the unit rate for each individual voltage level is fit for purpose due to the different interventions, and associated costs at each voltage level. This also reduces the risk of introducing outliers in terms of funding across DNOs due to different voltage mix levels. We believe this to be a mistake within the modelling suite and would expect a correction to be made in Final Determinations to ensure the disaggregated modelling is at the sub-category level. Further information is with Annex 5.

Furthermore, we disagree with Ofgem's assessment that SSEN did not provide volumes and associated unit rates as part of our RIIO-ED2 final submission. The volumes submitted were based on the latest data available at the time. Therefore, Ofgem's proposal to completely discount our information from its assessment is wrong, as is the statement in the Core Methodology "SSEN, [who] did not provide final volumes for this activity" and Ofgem's conclusion to "propose not to include SSEN's costs". We would expect that the volume data is not discounted within the Final Determinations and have provided more information within Annex 5 on this.

We welcome Ofgem giving us the opportunity to submit the very latest LiDAR data for SHEPD through the Draft Determination response for our RIIO-ED2 submission. As such, we are providing an addendum to our 418_SSEPD_NLR_OHL_Clearance EJP (Annex 15) along with a revised CV18 – OHL Clearance Business Plan Data Table for SHEPD. There are no further updates for SEPD as this was based on the most up to date data we have available from the 2019/20 LiDAR flight.

Question ID	Core-Q82.
Question	Do you agree with our proposed approach to assessing ESR costs?
Response	
Yes, we agree with the proposals to qualitatively assess ESR costs.	

Question ID	Core-Q83.
Question	Do you agree with our proposed approach to assessing QoS and NoSR costs?
Associated Evidence	
Title	**Link to Evidence**
Annex 10 - North of Scotland	Annex 10 – North of Scotland
Response	

We support Ofgem's proposal to remove QoS funding from all DNOs, which differs from RIIO-ED1 where the fast tracked DNO was awarded QoS funding. However, our support for the changes in the Draft Determination are contingent on Ofgem retaining its Design Principle[4] that target outputs should be funded through baseline allowances. If that were to be re-visited, a full consultation would need to be undertaken.

Regarding the Remote Generation Capex expenditure in CV15, as agreed in the bilateral discussion on 3rd Aug '22, this cost will remain in CV15 to enable costs to flow into Total Cost Type and a memo line (that will not add into the Cost Type) to CV15 will be added to ensure clear separation from QoS.

To provide further clarity we can confirm that the submitted Remote Generation Capex includes the following elements:

- [redacted] to replace the oldest and/or least reliable generators at Battery Point with two more efficient ones, supported by EJP reference 345_SHEPD_ENV_BATTERYPOINT
- [redacted] to install an additional capacity at Bowmore
- [redacted] mechanicals and civils work budget for RIIO-ED2 for our seven sites (with the O&M and Fuel costs being held in BPDT C8)
- [redacted] to replace the existing roof due to condition and associated building works at Battery Point

In addition, as part of the supporting evidence of the Remote Generation Capex, SSEN submitted the EJP reference 345/SHEPD/Regional/Battery Point and received engineering assessment outcome as 'Partially Justified', where the need of replacing the old engines at Battery Point is recognised. The EJP Addendum will be submitted as part of our DD response to address the engineering concern on the optioneering and deliverability risk. This is also included in the Annex 10 - North of Scotland within our DD response.

Regarding the reclassification of the NoSR costs as WSC costs, we agree that this provides consistency with other license areas and removes any confusion as similar approaches are adopted in ED2 to address WSC in other areas. As per discussion on 3rd Aug '22 with Ofgem (detailed in Annex 4 Interactions with Ofgem), it was agreed that only ED2 NoSR costs will be moved to CV19 with ED1 actuals remaining in CV15.

[4] See Paragraph 6.5 Point 3 - https://www.ofgem.gov.uk/sites/default/files/docs/2020/01/riio-ed2_framework_decision_jan_2020.pdf

Question ID	Core-Q84.
Question	Do you agree with our proposed assessment approach for Physical Security?

Response

We agree with Ofgem's proposed approach to assess physical security costs on a qualitative basis. Given the specific nature of these costs, we consider this to be appropriate.

We note Ofgem's DD position to reject our proposal for two new control centres. We have responded to Ofgem's feedback and provided additional information to address any outstanding concerns. Please see our response to SSEN Q7 for further details.

Question ID	Core-Q85.
Question	Do you agree with our proposed assessment approach for Flood Mitigation?
Response	
Yes overall, we agree with Ofgem's proposed approach for Flood Mitigation and agree with your proposal not to apply the risk-based approach used in RIIO-ED1. In paragraph 7.291, Ofgem propose setting an industry median rate unit cost. We agree with the unit rates as assessed within the disaggregated modelling suite which we consider to be reflective of the costs we will incur in delivering our flood mitigation proposals. Furthermore, we note that in paragraph 7.923 you propose to accept costs and volumes submitted by all DNOs (except for WPD). We welcome the adaptive approach Ofgem has taken to unit rates in CV16 and we accept how Ofgem has assessed the cost and volumes for SSEN as we believe that in SEPD we have a detailed EJP (7/SSEPD/ENV/FLOOD) to evidence our requested plans.	

Question D	Core-Q86.
Question	Do you agree with the proposed approach to assessing Rising and Lateral Mains costs?
Response	

We disagree with Ofgem's decision to use the DNO median unit cost based on both RIIO-ED1 and RIIO-ED2 data. Ofgem's proposed approach makes a number of implicit assumptions which don't reflect reality of our planned RIIO-ED2 interventions. For example, during RIIO-ED2 we will target a much higher proportion of RLMs within Multi-Storey buildings when compared to RIIO-ED1. Given that these buildings have a far greater number of individual floors the unit cost to replace, refurbish and inspect the RLMs in each building is higher.

As our RIIO-ED2 strategy and proposed interventions are fundamentally different from RIIO-ED1, we expect to see a significant, but justifiable, increase in the unit costs. Unfortunately, the CV18 table within the BPDTs do not allow us to submit cost and volumes based upon the number of floors associated with the buildings we target, instead it only enables us to report costs per building.

Our updated RIIO-ED2 strategy is a result of the ENA working group that produced Engineering Recommendation G104 for the assessment and management of Rising and Lateral Mains. This was completed following the Grenfell tower disaster and the subsequent learnings that have been adopted by the DNO community.

As such, it is important that Ofgem allows the RIIO-ED2 unit cost we have proposed so that we can target the higher risk multi-storey buildings. Without this unit cost, we will be unable to do so and this will create an inherent and unacceptable safety implications for current and future consumers. For this reason, we request that Ofgem revisits its decision on unit cost to allow us to the RIIO-ED2 rates we have proposed.

We also disagree with Ofgem's EJP assessment of our volumes. Our proposed volumes have been informed by a detailed inspection programme undertaken during RIIO-ED1. As per our reverse SQ on this topic (SSEN035) we would consider the inspection programme and the number of buildings inspected to be a statistically significant sample size that can be used in confidence as a reliable indicator of the number of RLM assets that will require intervention across our distribution network during RIIO-ED2. Please see our EJP Addendum for RLMs which describes the Cochrane formula used to calculate a significant sample size as applied to our RLM inspection programme.

Finally, we note the additional data that Ofgem has requested during the Draft Determination period on the number of customers associated with the inspections that have and will be undertaken. We welcome further engagement with Ofgem on their approach to RLMs as they review this additional data.

We note that Rising and Lateral Mains are a cost exclusion and as per our response to Q64 we would also expect the MEAV driver to exclude this asset type.

Question ID	Core-Q87.
Question	Do you agree with our approach to assessing WSCs?

Response

As per our response to CORE-Q52, SSEN agrees with the proposed UIOLI mechanism for WSC as well as the principles proposed to identify and justify targeted investment to address WSC.

In addition, and as per our response to CORE-Q83, we agree with the reclassification of the North of Scotland Resilience costs as WSC costs as this provides consistency with other license areas and removes any confusion.

Per para 7.303 we note that you intend to set an ex ante UIOLI allowance based upon submitted costs, but due to the inclusion of WSC expenditure within the Totex modelling there is by proxy an assessment made to this expenditure. We propose Ofgem classify WSC (*and North of Scotland Resilience*) type spends as excluded costs, so they do not impact the Totex modelling, flowing through as bespoke assessed costs.

This would enable the costs to enter the PCFM as submitted instead of how they are currently as assessed costs.

Question ID	Core-Q88.
Question	Do you agree with our proposed assessment approach for Losses?
Response	
We agree with Ofgem's proposed cost assessment approach for Losses as Ofgem have laid out in paragraph 7.308, where Ofgem find our Transformer Auto Stop Start (TAAS) costs to be justified and therefore have accepted these costs as submitted in full. We are fully committed to reducing electrical losses on our network. We were amongst the first DNO to include losses as part of our Scope 2 emissions in line with the GHG Protocol, and to propose a Losses Reduction Strategy. Reducing electrical losses on our network via our Losses Reduction Strategy will deliver £36m of societal benefits and enable network decarbonisation by allowing us to reach our Science Based GHG emissions reduction targets. We believe Ofgem could have gone further to drive more determined behaviour from DNOs to tackle losses. **Our position is fully detailed in our response to CORE- Q13.**	

Question ID	Core-Q89.
Question	Do you agree with our proposed assessment approach for environmental reporting?
Associated Evidence	
Title	**Link to Evidence**
Annex 8 – Environmental Annex	n/a
Response	

We do not agree with all of Ofgem's proposed cost assessment approach for environmental reporting, specifically SF_6 and Nature Based Solutions (NbS).

Both SF_6 and NbS proposals are critical to us achieving a credible Net Zero. Rejecting these costs will jeopardise our ability to meet the requirements under the Climate Change Act 2008 (r2019) and the Environment Bill 2022 legislation. SF_6 emissions reduction is a material factor in our BCF and not tackling SF6 head on as planned will affect our ability to make our publicly announced Science Based Targets. We would also need to restate our business plan commitments to reflect this both for SBTs and SF_6.

This decision puts three business plan outputs at risk, which in turn will prevent us from achieving a credible and ethical net zero:

1. Set an ambitious 1.5° Science Based Target (including losses) requiring at least a 35% reduction in our carbon footprint by 2028.
2. Reduce SF_6 emissions from our assets by a minimum of 35%, report on and begin to reduce our holdings
3. Baseline and further plan 2,000 hectares of native woodland and restore 1,200 hectares of peatland in our license areas, which are expected to remove up to 300,000 tonnes of $CO2_e$ by 2045.

All three of these outputs are strongly supported by stakeholders. This support has been consistent over the last few years, following Ofgem's DDs on July 27th 2022. We retested these outputs with stakeholders to ensure opinions hadn't changed considering the living crises we all find ourselves in. Our stakeholders remained strongly supportive in all three areas.

SBT Output - We note that Ofgem has stated in the Core Methodology Document in section A1.2 that they are proposing to accept our Science-Based Target (SBT). We welcome Ofgem's approach to SBTs and would like to see the framework evolve to encourage all companies across the sector to set ambitious science-based targets aligned to at least a 1.5° pathway. We firmly believe that a 1.5° target should be a minimum requirement across the sector, as an approach supported by Ofgem's Challenge Group, our CEG, Sustainability First and wider stakeholders and consumers. At our sustainability and environment workshop on 27th July 2022 we were praised for our transparency in our approach to setting SBTs, as well as for including Scope Three targets and we were encouraged to implement this approach as a matter of urgency. However, Ofgem's proposal to disallow costs associated with key activities that directly impact our SBT, such as SF_6, for emissions reduction, combined with decisions affecting our ability to transition away from diesel on our islands, will compromise our ability to meet this target. Ofgem have not been consistent in their approach here.

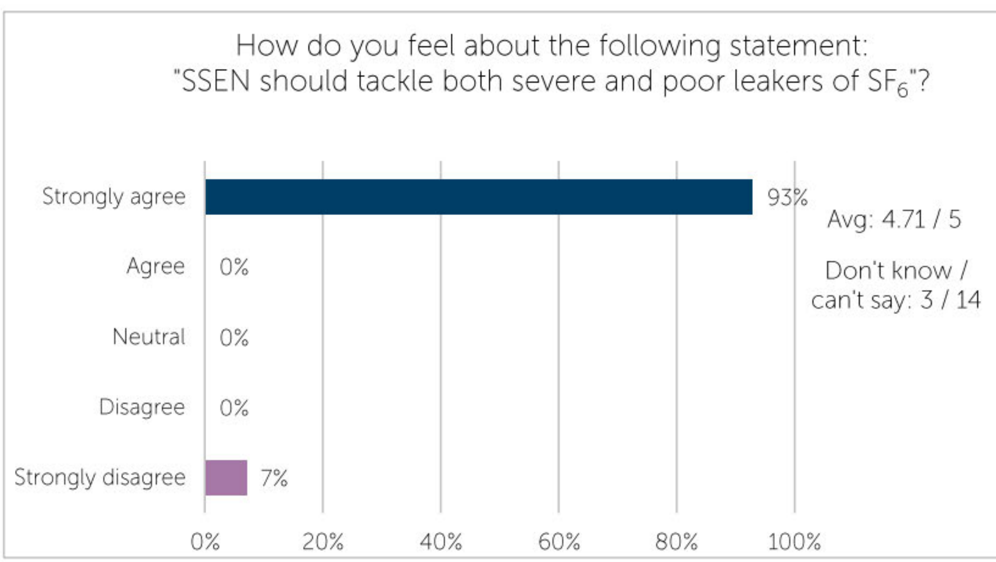
We have had our target accepted, but the initiatives which feed into our target disallowed. We urge Ofgem to consider the wider impact of these decisions, we cannot meet ambitious targets without ambitious initiatives.

Science Based Target Delivery – Sulphur Hexafluoride (SF_6) Output - We do not agree with Ofgem's proposed assessment approach for SF_6. Ofgem's proposal to remove this investment at DDs fails to consider the short and long-term impact on our ability to meet our publicly committed to, 1.5° SBT and will be to the detriment of current and future consumers. Ofgem must reconsider its approach at FDs in light of the additional evidence we have provided with this response. Our proposal not only addresses assets that are at end of life, but also assets that have a history of severe and poor leakage.

We note that Ofgem are approving all other DNOs SF_6 proposals without amendment. We have included a detailed SF_6 strategy linked to our investment in Appendix B of our Environmental Action Plan in line with the Ofgem minimum requirement, which mandated DNOs to implement a strategy to efficiently manage SF_6 assets. Ofgem's proposals fail to recognise our comprehensive and robust approach which sets out a clear strategy to reduce SF_6 emissions as well as decrease our inventory of SF_6, to effectively reduce emissions in the longer-term. We have included this work under our Environmental Action Plan and data tables, to provide clarity for stakeholders and Ofgem on progress against what will be delivered in ED2 to tackle SF_6 emissions head on. This aligns with the Ofgem aim to ensure that DNOs are reporting transparently on the environmental impacts arising from their networks and demonstrate how these are being mitigated. We have had further positive discussions with Ofgem on this matter and have provided our full response on why we do not support this consultation position alongside additional information requested by Ofgem at the bilateral meeting in section 2.1 of Annex 8 – environment.

During SSEN's sustainability and environment engagement workshop on 27th July 2022 we asked stakeholders for their opinion on our SF_6 proposal as shown below:

1. Do you think SSEN should tackle both severe and poor leakers of SF_6?



Stakeholders Comments:

- "It seems like this is such a potent greenhouse gas. If this is approaching the levels of problem we have with carbon, then it's a no-brainer." Environmental group
- "I agree that this is a good idea. We have had a lot of pollution incidents over the years, and this would help to reduce the amount of pollution across our catchment. However, I would stress that both of these leakers are key for us." Utility
- "Absolutely, these leakers seem to be a problem and need to be tackled." Government

Participants in the breakout rooms largely disagreed with Ofgem's consultation proposal to remove the SF6 investment for SSEN, whose costs were thought to be considered and justified.

In addition to our workshop, we have carried out bilaterals with key stakeholders, such as Sustainability First who commented that 'SF_6 is an unseen long term asset management risk, which if it's not addressed in ED2 it is stacking up problems and customers will end up paying more.'

Our CEG and the Challenge Group (at draft) also supported our SF6 Strategy and approach. Recognising that the upcoming F-Gas legislation changes, (expected to come into effect during ED2) are likely to include some form of prohibition on SF6 use - all companies need to have a plan to start reducing their holdings in SF_6 Bank now, our proposal does that. To disallow this investment is pushing the problem onto future generations and we could end up in another distressed programme of work similar to that of PCB replacements that we are experiencing now.

In our response in Annex 8 we have included a refreshed Cost Benefit Analysis (CBA) utilising current carbon values. The CBA produced for the original ED2 Business Plan submission used the BEIS 2018 valuation of the central scenario for carbon, £72 for 2028. The BEIS valuation was last updated in 2020 and the central scenario for 2028 increased to £272. The CBA used in assessing our investments therefore undervalues the current cost of carbon. We have therefore rerun the CBA assessment using updated carbon values (the BEIS 2020 carbon prices), with all other elements of the CBA remaining unchanged from the original CBA assessment as detailed in our original SF_6 EJP submission. This has a significant positive impact on the Net Present Value (NPV) of the investment options and indicates the importance of assigning an updated carbon valuation to this investment. Further details on this can be found in section 2 of Annex 8 – Environment.

Nature Based Solutions Output As part of the draft determinations Ofgem allowed no funds for our Nature Based Solution (NbS) proposal, despite this proposal being a cornerstone of our net zero strategy, as outlined in our response to Core-Q13. We know the cost of carbon will rise and while NbS will take 5-10 years to mature once developed they will deliver carbon sequestration over a 100-year span, removing residual carbon from the atmosphere and delivering wider biodiversity benefits as a result This investment helps us to deliver carbon removal solutions (that will be required) and on biodiversity net gain requirements (mandatory through legislation). Standard Offsetting does not do both. The initial investment required rises dramatically if a faster result is required; therefore, action now will help reduce costs and allow for a longer timeframe for maturation. Waiting until RIIO-ED3 to introduce these activities will increase costs and put a credible and ethical net zero at risk. Ofgem's decision to reject our Nature Based Solutions for carbon removal proposal directly impacts our ability to meet longer-term UK Climate Change legislation. Following further discussions with Ofgem and their core methodology requests, we have provided further evidence to support our original submission. This can be found in Annex 8, Section 2.2.

It is critical that Ofgem's FDs enable us to address all material factors contributing to our business carbon footprint – including SF_6 and Diesel to meet our SBT, and NbS for removals so that these collectively can enable a credible and ethical net zero. Acting now reduces the burden on future generations and we truly believe is the only way to protect current and future consumers from the cost of net zero.

Other categories - We agree with how all other Environmental costs and volumes have been allocated at DDs by Ofgem across the following categories, as we consider them to be reflective of the costs, we will incur in delivering these proposals as laid out in our EAP:

- Visual Amenity
- Oil Pollution Mitigation Scheme – Cables
- Oil Pollution Mitigation Scheme – Operational Sites
- Oil Pollution Mitigation Scheme – Non-Operational Sites
- Noise Pollution
- Biodiversity Baselining (Not Carbon Removal)

We note that whilst costs have been allowed for our FFC initiatives, our EJP was deemed 'unjustified' following positive discussions with the engineering hub we have provided further information as requested to move this to justified. This can be found in our response to Q13 and Annex 8.

(We note that PCBs are not covered in this question and covered in our response to Q90)

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q90.
Question	Do you agree with our proposed assessment approach for PCBs?
Associated Evidence	
Title	**Link to Evidence**
Annex 8 – Environmental Annex	n/a
Response	

No. We do not agree with how Ofgem has applied the baseline unit rates for PCBs. Delivering a programme of this work at this scale and differing locations, and with the underlying uncertainty will result in differing unit costs. We believe that developing an industry median using ED1 rates and forecast ED2 rates is not reflective of the costs to be incurred for these activities, which are required in order to meet our legal obligations.

We note that under paragraph 3.179 Ofgem state that "transformer replacement is a business-as-usual activity for the DNOs, and the unit costs can be reasonably determined prior to the commencement of RIIO-ED2." We agree that transformer replacement is a business-as-usual activity, and for this reason expect that the baseline **URs for this activity (PMTs & GMTs) in CV22 be the same as the URs for the BAU activity as applied by Ofgem in CV7 at draft determinations.**

We welcome Ofgem's intention to accept volumes as there is a legal driver to complete this work by a defined deadline, as stated in paragraph 7.316.

In the main, we agree with Ofgem's proposal for addressing PCB contamination in Pole Mounted Transformers (PMTs) through a volume driver in RIIO-ED2. However, **we do not agree with the all PMTs being dealt with through the UM** and believe the PMTs where there is certainty should continue to be dealt with through baseline volumes as applied in DDs. (Our full response to the UM position can be seen in Q16)

We accept that the UM will cover only PMTs. However, given the legal requirement in place also affects GMTs, it is reasonable for DNOs to expect that a funding route for GMTs should also exist. We consider that the correct approach is to recalibrate our baseline volume to prioritise delayed installations and GMTs, utilising the UM for PMTs. This approach allows us to plan and allocate those allowances in a way that is in the best interests of our consumer, while progressing with the removal of highly toxic chemical compounds from our network in line with our legal obligation. We will report on this openly and transparently to Ofgem through table CV22. We have adjusted our baseline volumes to prioritise all predicted GMT related activity through baseline funding this will mean additional baseline funding will be required, and we will **be resubmitting CV22 to reflect this.**

In addition, we are currently experiencing delays with the delivery of PCB related activities in ED1. This is partly as a consequence of a lack of clarity from Ofgem around the appropriate funding mechanism for PCB replacements in ED1, both PMT and GMTs. A summary of key milestones associated with this work can be found in Annex 8 Section 4.1. Key points are summarised below:

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Background

In **June 2019**, new legislation introduced the need for all DNOs to identify and remove from use, equipment containing more than 50ppm PCBs and volumes greater than 50ml by December 2025. Working with the environment agencies, Ofgem and Government, the ENA produced a 'PCB Strategy for Electricity Networks' in **October 2020**, this set out to address the changes resulting from the Regulations so that any oil-filled electrical equipment within scope, is identified, controlled and removed/remediated to reduce risk of PCBs entering environment.

Funding Options

In **December 2020**, the ENA on behalf of DNOs, submitted a paper proposing different funding mechanisms for PCBs in RIIO-ED1 to Ofgem. This was at a request from Ofgem to present potential funding routes for new allowances, which Ofgem had intimated that given the new requirement new funding would be expected.

During the first half of 2021, there was little engagement on taking the PCB funding discussions forward. However, following various working groups, including Cost Assessment WGs for ED2, PCBs were raised again. This led to the ask from Ofgem that DNOs were to work towards a proposal for incremental funding in ED1 that all DNOs would support and Ofgem could implement sufficiently early enough in 2021, to allow DNOs to begin to replace transformers no later than January 2022. The ENA PCB – ED1 Funding Mechanism group engaged from **July 2021**.

From **July 2021 to December 2021**, work continued within the WG to progress the funding options. With some engagement with Ofgem. In l**ate December 2021** – it was noted that Ofgem would be engaging in January 2022 on the detail of the proposed mechanism.

Submissions

January 2022 – Ofgem allowed for requests to PCB-related funding to be submitted under the Green Recovery mechanism. However, changed their position on **13th May 2022** and decided to not extend the GRM to include costs associated with PCB related activities,

We have remained optimistic that a mechanism would be confirmed in ED1 and forecasted delivery under that assumption. Unfortunately, a suitable mechanism has yet to materialise, resulting in us not having made progress in line with original ED1 forecasts. This naturally pushes further work into ED2 for delivery. We asked Ofgem again through the reverse SQ process (SQ SSEN0019) to confirm how DNOs should recover efficient RIIO-ED1 costs accrued associated with PCB activities through the reverse SQ process and received the following response:

> *As noted in our letter entitled "RIIO-ED1 Green Recovery Scheme – Decision on potential extension for accelerated removal of polychlorinated biphenyls" published on 13 May 2022, we may, subject to further consultation on the methodologies that apply, use the process to close out the RIIO-ED1 price control to consider any revisions to the RIIO-1 Legacy Financial Model to account for necessary expenditure on PCB removal not covered through existing RIIO-ED1 allowances where this can be demonstrated to be in consumers' interest.*

In addition, delays have been incurred as a result of Operational Restriction OR-NET-ENG-068 being applied to Kyte PMTs that were a significant part of the replacement programme. Due to failure events on energisation, we temporarily halted orders from Kyte whilst detailed investigations into root causes of failures were conducted, and corrective actions were identified and implemented.

Manufacture has been paused for over four months and is due to resume following the factory's scheduled summer shutdown. In the interim we have had to procure from alternative equipment manufacturers with lead times ranging from 5 to 10 months.

As a result of these issues that are primarily out of our control, we have been delayed in delivery and part of our ED1 forecasts are pushed out into ED2. **Our revised baseline and UM volumes reflect this change.**

Question ID	Core-Q91.
Question	Do you agree with our proposed assessment approach for Property?
Associated Evidence	
Title	**Link to Evidence**
Annex 10 – North of Scotland	n/a
Response	

We disagree with the cost assessment approach for Property:

1 We do not agree that assessing Property Management BSC and Non-Operational Property together is appropriate.

2 As presented to Ofgem at the April 2022 CAWG, the impact of UG cable having an 8x higher weighting than OHL within MEAV distorts the benchmarking areas relating to Indirect spend including Property. The costs associated with Property are not materially different for the installation of Overhead Line compared to Underground Cable and as such, MEAV should be recalculated with a 1.5x activity weighting at each voltage level for UG vs OHL to represent Indirect activity. (see CORE-Q102.)

3 SHEPD incurs a material level of costs due to our Company Specific Factors (CSFs) for Islands (inc. Subsea) and Sparsity. At RIIO-ED1, Ofgem accepted SHEPD's claim for these factors and partially accepted the quantified additional costs. At DDs Ofgem have rejected all SHEPDs Property related Company Specific Factor claim. Property cannot be fairly assessed for efficiency without pre-modelling adjustments for these.

4 **Approach to assessing Property Opex and Capex together:**

Combining Non-Operational Property and Property BSC costs together is an unjustified departure from the RIIO-ED1 cost assessment methodology. Capex property spend is lumpy and atypical in nature. Consequently, this is an area where it should not be expected that each DNOs spend profile over a price control would align. Assessing Capex spend with Property Management Business Support costs looking at a relatively short time period, when considering property asset life (and including COVID impact of periods where construction was limited) does not make operational sense as the two spends are not well linked. Our view is that these two cost areas should be separately assessed. As noted in RIIO-ED1 draft determinations *"For property, we no longer include non-operational capex property costs in the BSCs assessment. We sought greater transparency of these costs and concluded that capex expenditure should not be captured within the opex assessment of business support."* We do not see that sufficient evidence has been provided by Ofgem to justify a departure from the approach set at RIIO-ED1.

MEAV as a driver

While we consider the use of MEAV appropriate in other areas, the calculation of MEAV is inappropriate for Indirect areas of spend (CAI/BSC/ V&T and Property). OHL and UG cables have a similar indirect resource requirement and property use implication, and thus should have equal weighting in MEAV. However, in the MEAV calculation, UG cables are eight times more expensive than OHL

Our own assessment using SEPD data shows that only Core CAIs would require additional effort associated with UG vs OHL. All other categories are like for like when comparing UG Cable vs OHL including Property and the impact is 1.5x more activity not 8x. As such, MEAV should be recalculated with an activity-based weighting at each voltage level for UG vs OHL as described in CORE-Q102 (Cost Assessment Annex E - Review of the cost assessment in Ofgem's RIIO-ED2 Draft Determinations)

Company Specific Factors

North of Scotland (Submarine Cables) Response to Property (C5)
SSEN is the only DNO that has a requirement to hold a strategic stock of multiple spare submarine cables to support reactive fault replacement projects. We do this to reduce replacement lead-times and minimise disruption to customers and reduce our environmental impact from the use of Remote Embedded Generation. This prevents having to wait for manufacturing slots when a fault occurs. The strategic cable stock allows a timely and efficient fault replacement lead-time once engineering is complete and offshore installation vessel secured.

Holding a strategic stock of standard cable specifications was an efficiency introduced during RIIO-ED1 to not only reduce fault replacement times, but also offer beneficial cable procurement unit rates through optimal economies of scale. Furthermore, it removes the risk of not being able to source replacement cables (of standard specification) under fault conditions.

It is therefore not appropriate for Ofgem to assess the requested cable storage and preservation costs Ofgem proposes to do in Draft Determinations and apply a 22% reduction. As explained elsewhere in the consultation responses, all unique costs associated with delivering submarine cable replacement projects should not be assessed in a broad-brush approach as per other non-operational property costs. They should be assessed as a company specific factor. Further information is provided with the North of Scotland Annex 10.

SSEN have submitted an allowance request for cable storage and preservation at both Nigg and Burntisland quayside storage facilities (C5 = [redacted]). The costs proposed are actual Frame Agreement costs for the duration of the Price Control. They are not comparable in any way given the number of storage carousels being used and volume of cables / ancillaries currently in storage.

We have provided further information to support our Company Specific Factors for Property (OPEX and CAPEX) in Annex 10 – North of Scotland.

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q92.
Question	Do you agree with our proposed assessment approach for STEPM?
Associated Evidence	
Title	**Link to Evidence**
Annex 10 – North of Scotland	n/a
Response	

We agree in principle with Ofgem's proposed approach of cost assessment for STEPM using which uses ratio benchmarking to assess STEPM. However, for SHEPD, our regional factors associated with Sparsity, Islands and Submarine Cable have only been partially accepted at DDs.

North of Scotland (Submarine Cables) Response to STEPM – Non-Op (C7)

SSEN own and operate more than 110 submarine cables connecting over 59 remote communities from the islands around Scotland. No other DNO has a comparable fleet of submarine cables. As stated in the response to Consultation Question ref. CORE-Q54 (NARMS), there is a robust and industry acknowledged process in place for the proactive replacement of our submarine assets. SSEN are also keen to embrace innovative technology to further build data on the real time condition of our submarine cable assets.

One method SSEN use to obtain health data of our cables is through regular offshore General Visual Inspections (GVIs). However, SSEN are also keen to adopt innovative real time submarine cable condition monitoring technology, leveraging the benefits of the Network Innovation Allowance (NIA) funding. SSEN included [redacted] under C7 STEPM – Non-Op for retro-fitting SUBsense cable condition monitoring systems on x10 (ten) of our existing submarine cables during RIIO-ED2.
SUBsense is the SSEN project name for Distributed Acoustic Sensing (DAS) which is a technology that can be installed on submarine cables with an embedded fibre optic bundle. SUBsense was an NIA project in RIIO-ED1 identified as being a solution to assist with fault finding and extending the usable life of submarine cables. The technology provides information and alerts if cables are subjected to excessive cable movement on the seabed which can lead to premature wear or environmental damage. Alerts will also be generated in the event of any third-party interaction from anchor snags, etc.

As a default, SSEN will install SUBsense technology on all proactive cable replacement projects in RIIO-ED2. The specific request under C7 STEPM – non-Op is to cover the cost of retrospectively installing SUBsense on x10 existing cables previously installed within RIIO-ED1 which include fibre cores.
It is therefore not appropriate for Ofgem to assess the requested allowance as per Draft Determinations by applying a 22% cut. As explained elsewhere in the Consultation Responses, assessing all unique costs associated with owning and operating submarine cable assets in the same way as other costs that all DNOs face is wrong.

SSEN have submitted an allowance request for x10 systems to be retrospectively installed with unit costs based on a competitively tendered procurement process. They are not comparable in any way to other DNOs given the innovative technology and number of units proposed.

We have provided further information to support our Company Specific Factors for Property (opex and capex) in Annex 10 – North of Scotland.

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q93.
Question	Do you agree with our proposed assessment approach for Vehicles and Transport?
Associated Evidence	
Title	**Link to Evidence**
Annex 10 – North of Scotland	n/a
Response	

We disagree with the approach taken for Vehicles and Transport, which we believe is fundamentally flawed:

- We do not believe that using RIIO-ED1 + RIIO-ED2 data is appropriate for the new and significant step up required to be delivered in this price control to enable Net Zero, noting in particular the transition to electric vehicle fleets required to meet our 1.5° SBT target. Only RIIO-ED2 data should be used for cost assessment purposes.

- As presented to Ofgem at the April 2022 CAWG, the impact of UG cable having an 8x higher weighting than OHL within MEAV distorts the benchmarking areas relating to Indirect spend including Vehicles and Transport. The costs associated with Vehicles and Transport are not materially different for the installation of Overhead Line compared to Underground Cable and as such, MEAV should be recalculated for CAI and BSC, Property and Transport weighted by activity levels for Underground cable and Overhead Line. From our operational insight we assess this as 1.5x (rather than 8x) for UG cable vs OH line at each voltage level.

- SHEPD incurs a material level of costs due to our Company Specific Factors (CSFs) for Islands (inc. Subsea) and Sparsity. At RIIO-ED1, Ofgem accepted SHEPD's claim for these factors and partially accepted the quantified additional costs. At DDs Ofgem have rejected all SHEPDs Vehicle and Transport related Company Specific Factor claim. Vehicles and Transport cannot be fairly assessed for efficiency without pre-modelling adjustments for these.

- We agree with the approach of assessing Vehicles and Transport (CAI) and Non-Operational Vehicles together per RIIO-ED1

<u>Cost Assessment Time Period:</u>

RIIO-ED2 marks a step change to our fleet due to Net Zero deliverables and we are committed to decarbonising 100% of its vehicle fleet under 3.5tn and 50% of fleet over 3.5tn by 2030 as part of our EAP, in line with our 1.5 degree SBT. This is a significant change from our RIIO-ED1 cost base.

Additionally, as highlighted in our workforce resilience strategy the increase in volumes of work in RIIO-ED2 will impact our operational workforce, which is forecast to grow by 290 Working Time Equivalent (WTE) over the RIIO ED2 period along with an significant increase in trainees leading to an increase in our fleet. This will therefore mean a larger operational fleet for our workforce in parallel to the requirement to decarbonize our fleet

Volumes of work and EV Environmental targets mark a fundamental change from RIIO-ED1. Whilst MEAV is representative of network scale, it is not an intuitive driver for the changes in Vehicle and Transport costs relating to decarbonization. Furthermore, unlike previous price controls, there is a disproportionate weighting of RIIO-ED1 costs included in the benchmarking ratio due to the 8-year period of ED1. To remedy these issues, it is our view that Vehicles and Transport should be assessed using the RIIO-ED2 time period only.

MEAV Cost Driver:

While we consider the use of MEAV appropriate in other areas, the calculation of MEAV is inappropriate for Indirect areas of spend (CAI/BSC/ V&T and Property). OH line and UG cables have a similar indirect resource requirement and vehicle use implication, and this should be reflected in MEAV. However, in the MEAV calculation, UG cables are eight times more expensive than OHL.
Our own assessment using SEPD data to represent an average share of underground cable / overhead line, shows that only Core CAIs would require additional effort associated with UG cable vs OHL but not 8x the level which the use of MEAV implies. All other categories are like for like when comparing UG Cable vs OHL including Business Support Costs. Our analysis shows a ratio of 1:1.5 OHL vs UG cable is required for Indirects. As such, we propose that MEAV should be recalculated for this category using our weighting for OH line and UG cable at each voltage to reflect activity.

Company Specific Factors:

For SHEPD we disagree with the Draft Determination for our Company Specific Factors (Sparsity and Islands) along with the assessment of Regional Wages – please refer to our North of Scotland Annex 10 and resubmitted M25 which demonstrates the actual spend in RIIO-ED1 on our Company Specific Factors is in line with our RIIO-ED2 assessment.

Net after Price Control Allocation:

The Non Price Control allocation for Net after Allocation is required to be adjusted to reflect the ratio of in / out of price control CAIs post cost assessment. We disagree with the current adjustment within the PCFM interface file which removes the full pre cost assessment value from the indicative allowances and this should be based on the Net before Allocation to Net After Allocation ratio.

Question ID	Core-Q94.
Question	Do you agree with our proposed assessment approach for HVPs?
Associated Evidence	
Title	Link to Evidence
Annex 10 – North of Scotland	n/a
Response	

We agree with Ofgem's approach to assess HVPs qualitatively due to the Atypical and lumpy nature of spend.

We recognise that Ofgem intended to assess HVP through a Company Specific Factor approach and have made our comments regarding this assessment within Supplementary Question SSEN 030 and Annex 10 – North of Scotland. SSEN believe all CV7 and CV25 proactive investments should be accepted as CSF, and therefore excluded from pre-modelling. In Ofgem's response to SSEN 030 they state other DNOs also have submarine cables. No other DNO has a fraction of the portfolio held by SSEN, and therefore disagree with how the CV7 and CV25 proactive investment costs have been allocated. SSEN strongly recommend that all subsea cable costs are excluding in full for separate assessment.

While we appreciate the reasons why Ofgem has left determination on these matters for further discussion, we would stress the urgency on opening dialogue to discuss any further information that Ofgem may require to make a determination on our HVP proposals. Supplementary information to further support the justification of the Skye to South Uist subsea cable HVP has been provided within Annex 10 – North of Scotland. We note the allowances were accepted for Fleet/Bramley, our load related EJP, though Ofgem raised concerns with the EJP. We have addressed these in a submitted EJP addenda and believe this project is now fully justified and should continue to have associated allowances fully accepted.

All subsea cables should be removed from the standard modelling suite and assessed independently. Further subsea cable cost modelling observations have been highlighted in CORE-Q63 (Normalisation).

Similarly, in HVPs (CV25), a single project (Skye to South Uist) was proposed with a given volume and cost. The Ofgem Engineer Hub assessed the EJP as 'Unjustified' and therefore no volume was awarded, yet a cost of £14.03m awarded. Ofgem's proposal does not allow us to practically replace or upgrade cables to continue to ensure security of supply and enable the connection of LCTs on the islands. It is unclear what Ofgem expect us to deliver here, and the costs awarded if spent on the cable would only amount to delivering half the cable.

It should also be noted that SSEN de-linked the two cables proposed from Skye to South Uist (South and North route) as per our April '22 re-submission. The importance of proactively replacing the Skye to South Uist cable (South Route) is critical with further justification provided within the North of Scotland Annex 10. The second cable (North Route) will be further assessed as part of the Hebrides & Orkney Whole System assessment.

We require Ofgem to provide us with a full explanation at the Final Determination of the allowed baseline costs in CV7 and CV25 for subsea cables split between HV and EHV and to show clearly how the engineering assessment links to the cost modelling process. This should consider all our feedback

and additional evidence on company specific factor modelling adjustments and engineering justification papers contained with Annex 10 – North of Scotland. We believe with this Ofgem will be able to approve in full our CV7 and CV25 costs for asset replacement, as per the April'22 re-submission. We are happy to support Ofgem with assessing these costs ahead of the final Determination.

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q95.
Question	Do you see any merit in setting a HVP threshold for RIIO-ED2, and if so should it be based on the RIIO-ED1 threshold?
Response	
We see merit in setting a HVP threshold at the same level as the RIIO-ED1 threshold value, £25m (in 12/13 prices). In preparing our business plan we used the RIIO-ED1 value as a proxy value to guide our classification of HVPs in the Business Plan Data Tables (CV25). There is no obvious reason to change the RIIO-ED1 threshold for RIIO-ED2 and removing the threshold would create unnecessary ambiguity.	

Question ID	Core-Q96.
Question	Do you agree with our proposed assessment approach for faults and ONIs?
Associated Evidence	
Title	Link to Evidence
Annex 10 – North of Scotland	n/a
Response	

We broadly agree with the approach that Ofgem has taken for the assessment of Faults and ONIs; however, more work is needed on the treatment of submarine cables in the SHEPD licence area.

Our forecast of submarine cable faults within CV26 was for three EHV and three HV faults over the period. This was based on an assessment of the number of faults that we would plan to repair during the period; however, the total number of faults was intrinsically linked to the submarine cable uncertainty mechanism being agreed which would be for replacement (N.B. CV26 baseline funding for fault repair and the UM for replacement given the high-cost difference and associated variability of replacement).

As noted during the North of Scotland cost modelling bilateral on 12th August 2022 (see Annex 4 Interactions with Ofgem), Subsea Cable faults were not marked as a Regional Factor in our submitted M25 table. We are resubmitting our M25 table as part of our response to the Draft Determination and consider that Ofgem should now remove Subsea Cable Faults from the regression analysis due to the unique and material nature of the activity. Further clarification of Regional Factors and specifics of M25 in the BPDT are included within Annex 10 – North of Scotland.

In a related area, we have proposed a subsea cable UM for replacing cables in response to faults, due to the highly uncertain nature and large consequence of failure cost associated with subsea cable. It is prudent to deal with any additional subsea cable fault risks beyond those included in our baseline within a UM, as there is a great degree of uncertainty around the probability of failures. It is not good value to existing or future consumers to have the risk fully built into baseline. Further clarity on the specifics of the proposed UM is included within SSEN-Q8 and Annex 10 – North of Scotland.

If Ofgem ultimately rejects our balanced funding approach which utilises a combination of baseline and UMs, then we would expect our allowances for faults costs (CV26) to be increased in the Final Determination by between £109m and £199m. This would be necessary to account for the additional risk we would be taking through our baseline plan, which was not in our original business plan submission, and that no other DNOs face for the reasons we outline above. We provide further details of our calculation in our response to SSEN-Q8.

Ofgem's approach fails to recognise the impact on existing and future customers, including in terms of security of supply for some of our most remote communities and reducing carbon emissions. In the event of Ofgem continuing to adopt the position set out in the DD and failing to recognise the need for a UM in this area, and given the need to ensure security of supply, we may be required to reroute funding from other stakeholder-led outputs. This further underlines the requirement for a UM.

Question ID	Core-Q97.
Question	**Do you agree with our proposed assessment approach for Tree Cutting?**
Associated Evidence	
Title	**Link to Evidence**
Annex 4 - Ofgem Engagement	n/a
Annex 15 - Non-load EJP Addendums	n/a
Response	

We fundamentally disagree with the methodology that Ofgem has used to assess the CV29 tree cutting allowances. Ofgem should revisit its position in this area: (1) to reflect the LiDAR data SSEN has used to justify our volumes; (2) to adjust the benchmarking methodology used within the Disaggregated Modelling; and finally (3) to take account for the potential cost implications associated with Ash Dieback. Ofgem must fund safety critical work required to deliver compliance with Health & Safety Executive (HSE) legislation such as ESQCR. If it does not, DNOs will have to spend anyway which in effect makes cutting this area a general cut to the plan. We would also note the reductions in Tree Cutting funding will affect our ability to hit baseline targets; but this is compounded by the fact that the incentives that can be gained through IIS are not sufficient to enable us to meet our stakeholder led output. See our responses to CORE-Q46 to CORE-Q49 for further detail on this point. Please also see the Tree Cutting Section of Annex 15 Non-load EJPs addendums.

1) **Analysis of volumes informed by LiDAR:**

In our CV29 Tree Cutting EJP feedback, Ofgem has indicated that the CV29 volumes we have proposed are not fully justified as our existing LiDAR data cannot be relied upon as an accurate quantification of the number of spans that are affected by trees and vegetation and must therefore be managed to meet ESQCR compliance. Ofgem has said that this is due to future LiDAR surveys will be carried out and may provide a different view on the required volumes:

> "We consider that the next LiDAR surveys due to be undertaken in 2025 and 2026 will better inform future volumes. There is therefore a potential risk in the proposed volumes until the next LiDAR flights are complete. Future volumes will then be more accurate. SHEPD volumes could change following LiDAR data that maybe available prior to Final Determinations"

SSEN strongly disagrees with the feedback Ofgem has provided above. The suggestion that current LiDAR inspection data cannot be used to justify our RIIO-ED2 volumes as there is a future LiDAR inspection, which may provide a different answer, is not credible. This is a circular argument given that in 2025 and 2026, the same point can be made again about the next set of LiDAR surveys that would be scheduled for 2029 and 2030. This position would effectively mean that we could never justify our CV29 volumes since there will always be a future LiDAR survey scheduled 4-years after the previous one. This is clearly unreasonable.

Ofgem has also contradicted its own position on the use of existing LiDAR data to justify RIIO-ED2 volumes. For its assessment of Overhead Line Clearances, Ofgem has stated the following:

> *"We propose to accept the other DNOs' submitted volumes, based on the submitted supporting documents which detailed their volume forecast methodology. In this respect, we*

note that most DNOs have based their forecasts on previous volumes or have introduced the use of LiDAR into their inspection regimes which ensures greater data accuracy."

This is a clear contradiction and demonstrates that our existing LiDAR data should be used to justify the CV29 tree cutting volumes we have proposed. There is nothing materially different in the accuracy of LiDAR data when predicting CV29 volumes as compared to predicting overhead line clearances, and therefore no reasonable justification for Ofgem's inconsistent approach in this respect.

During the Cost & Engineering Bilateral held with Ofgem on the 28th July 2022 (as detailed in Annex 4) we discussed the value of our current and latest LiDAR data. We described how these surveys have provided us with a detailed 3D model of our entire overhead line network which shows the exact location of every single tree that sits alongside our overhead line network and the distance of these trees from our overhead line assets. As a result, we can directly demonstrate the need to intervene upon every single span we have included in our forecasted RIIO-ED2 volumes.

Ofgem also responded to our reverse SQ (SSEN020) on this topic when asked why our LiDAR informed "spans cut" volumes have not been selected. Ofgem responded with:

"This EJP has not been treated as a disallowed cost exclusion in the Tree Cutting disaggregated model. Our position for Draft Determinations is to propose that SSE's submitted tree cutting costs and volumes should be used and benchmarked with other DNOs, given we propose to use spans affected as the cost driver for Tree cutting."

However, this is not the case. As described in more detail below, the disaggregated modelling uses the lowest reported "spans affected" volume from DPCR5 through to the end of RIIO-ED2. It is therefore not true that our LiDAR volumes have been used within the benchmarking.

Furthermore, given the response to this question it is unclear why our Tree Cutting EJP has been classified as 'Partially Justified' given that the EJP feedback does not correspond to the SQ response quoted above.

As such, we would request that Ofgem revisits its position on our CV29 tree cutting volumes and awards the full 'spans cut' volumes that have been proven by our most recent LiDAR surveys.

2) Disaggregated Modelling

Within its core methodology document for CV29 Tree Cutting, Ofgem has indicated that it proposes to use 'physical cuts' and 'inspections' as drivers for ENATS 43-8. However, upon review it appears that Ofgem has in fact used 'Spans Affected' as the driver for ENATS 43-8 which is not actually a measure of physical activity, instead it is a measure of how many trees there happens to be alongside each DNO's overhead line network.

'Spans Affected' does not directly correlate to the actual activity undertaken by each DNO (i.e. 'Spans Cut' or 'Spans Inspected') given that each DNO has its own cut and inspection frequencies that reflect the rate at which trees grow in their licence area and the frequency needed to meet ESQCR compliance mandated by the Health & Safety Executive (HSE). In fact, some DNOs (such as SSEN) have not submitted any volumes for 'spans inspected' for RIIO-ED2 given that LiDAR will now replace the need for manual inspections to determine the number of affected spans. SSEN's own 'spans inspected' volumes instead correspond to our targeted Ash Dieback inspection which has been proposed to complement the Ash Dieback UM.

We note that within the cost assessment Ofgem has added up total spend across 'spans cut', LiDAR, and 'spans inspected' and benchmarked this against the lowest number of 'spans affected' recorded across DPCR5, RIIO-ED1 and RIIO-ED2. This assessment is carried out by voltage level and results in a unit cost per 'span affected'. Given that 'spans affected' is not actually a direct measure of tree cutting activity, a unit cost per 'span affected' is not a useful measure of cost efficiency. A DNO with the same number of spans affected may for legitimate reasons be undertaking a higher volume of 'spans cut' when compared with another. Furthermore, some DNOs may be underdelivering their 'spans cut' volumes and will then consequently benchmark favourably if a unit cost per 'span affected' is used. As such, this is clearly not a useful measure of efficiency or a good way to compare DNO tree cutting performance.

Furthermore, the LiDAR data we have recently acquired has allowed us to better demonstrate the density of trees alongside our overhead line network and the percentage of spans that are considered either Red, Amber or Green. This is a direct indication of the amount of physical tree cutting that is required on each span, and the justification of our higher unit cost in SEPD, as per our final plan BPDTs. We can also then use this data to compare with other DNOs that have undertaken a LiDAR survey.

When comparing our SHEPD and SEPD distribution networks we can see that SEPD has a much greater proportion of spans that are classified as 'Red'. This reflects the must faster growth rate that our southern network experiences when compared to Scotland and other parts of the country. Historically we have managed the volume of affected spans in SEPD over a 4-year tree cutting cycle.

However, as a result of the faster growth rates we have learned that a 4-year tree cutting cycle drives a higher unit cost per span given that more physical cutting is required when we revisit each span. Please see a table below which shows the percentages of Red, Amber and Green spans in SHEPD compared to SEPD.

As shown below, our SEPD area has a much greater proportion of 'Red' spans that are more costly to intervene upon. A 'Red' span will require more physical cutting at greater cost per span than an 'Amber' or 'Green' span. Therefore, a DNO with a greater proportion of 'Red' spans will require a greater unit cost to ensure the spans are cut to meet ESQCR and ENATS 43-8 compliance.

Voltage Level	SHEPD Split of Affected Spans			SEPD Split of Affected Spans		
	Red	Amber	Green	Red	Amber	Green
LV	15.6%	42.4%	42.0%	56.8%	13.0%	30.2%
HV	12.3%	25.5%	62.1%	27.0%	26.7%	46.3%
EHV	11.8%	10.0%	78.3%	29.1%	13.2%	57.6%
132kV	-	-	-	30.9%	30.2%	39.0%

It is for this reason that we intend to move to a 1-in-3-year tree cutting cycle for SEPD from the start of RIIO-ED2. However, until the first cycle is complete, we will still experience a higher unit cost due to the faster growth rate in the South of England and the additional cutting that this necessitates.

As such, **the industry median unit cost is not appropriate for SEPD** due to the additional tree cutting that is required on each span when compared to other parts of the country. This regional difference should be reflected directly within the unit cost we are awarded for RIIO-ED2.

The LiDAR data shown in the table above also supports the independent data provided with the ADAS report that complements our Tree Cutting EJP as quoted below:

> *"Overall, the burden of managing the potential risk to the OHL network from trees in the SSE (Southern) region can be expected to become more complex, time consuming and costly as climate change continues to cause the region to experience warmer and drier conditions. The relatively high number of trees across the region, particularly of those species which are already being affected by known pests and pathogens, represents a larger responsibility for the DNO in terms of monitoring and cutting of trees when compared with the other DNOs in the UK."*
>
> *"The SSE (Southern) region experiences the highest average USD (growth rate) at baseline. This will likely also continue to be the case into the next decade according to UKCP18 climate projections."*

As such, we propose that Ofgem make the following amendments to their cost assessment for CV29 Tree Cutting:

- Remove the volume adjustment against spans affected. Rather than using the lowest 'spans affected' volume reported across DPCR5, RIIO-ED1 and RIIO-ED2, accept the 'spans cut' volumes we have proposed given that it is justified by our latest LiDAR data (as described above) and reflects the fact that tree grow faster in SEPD than any other license area in Great Britain. We have a 3D model of our entire overhead line network and can demonstrate the need to intervene upon every single one of the hundreds of thousands of 'spans affected' included within proposed volumes.
- Split up the subsequent unit cost assessment by both activity and voltage to ensure a fair comparison is made and to ensure that outliers like the LiDAR cost and our Ash Dieback network survey are not included within the assessment.
- Award a higher unit cost to our Southern distribution network (SEPD) given the higher proportion of 'Red' spans on our network that required additional tree cutting and hence cost.

3) Ash Dieback Treatment:

Within the 'RIIO-ED2 Draft Determination SSEN Annex' and in response to our reverse SQs, Ofgem has stated that it expects DNOs to manage the risk associated with "new or emerging challenges such as Ash Dieback" within the existing CV29 allowances. We provided a response to Ofgem's rejection of our UM proposal within RIIO-ED2 Draft Determination SSEN Annex, SSEN Q-8.

We acknowledge Ofgem's response to our SQ SSEN013 that: "*As we set out in the RIIO-ED2 SSMD Annex 1 paragraphs 8.109 to 8.112 "DNOs will be required to manage the risks associated with new or emerging challenges such as Ash dieback*".

However, our approach is in existing and future consumers' better interests to managing the uncertainty. Undertaking a detailed survey will allow us to determine proximity of trees to our network and determine the cost 'scenario' each tree fits within. We can then use that as clear evidence through a re-opener application to ensure consumers are only exposed to reasonable risks and costs. The principle of the approach proposed is similar to the one set out by Ofgem for PCB replacement, which also uses an inspection programme to determine intervention need.

Moreover, our CEG have signalled their support for a mechanism: "*The CEG is supportive of the baseline survey costs and at this stage a UM would seem appropriate.*"

Should Ofgem not accept our UM, we would expect our baseline tree cutting costs in CV29 to be increased to accommodate the ongoing risk we would be expected to manage. We have set out in the table below the additional cost range we would use as a starting point for a further conversation with Ofgem if our UM is rejected. Our range is reflective of the increased survey work we have undertaken since the submission of the final business plan.

£m	Current M13 value	Very low	Low-mid	Mid-high	High	Very high
SEPD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SHEPD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SSEN	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Diseased trees present a real safety and resilience threat to the network. We must deal with this threat in a timely manner to avoid catastrophic impacts to our network, people, and the public. Should Ofgem continue to reject additional costs then we be forced to re-examine the delivery of funded baseline outputs in other areas of our plan so that we can continue to meet our safety and resilience obligations.

In addition, within section 7.78 of the core methodology document Ofgem have explained that they have reclassified the M13 costs associated with ENWL's Ash Dieback into the baseline ask:

"ENWL: [redacted] of forecast cost for LRE uncertainty mechanisms and [redacted] of forecast costs for diversions, tree cutting (ash dieback) and environmental reporting (PCBs)"

It is unclear why these costs have been reclassified for ENWL, but the same costs have not been reclassified for SSEN given that our own forecasted cost have also been split between a baseline ask and the proposed uncertainty mechanisms. **For the avoidance of doubt**, our baseline costs are those we have certainty on, whereas the UM costs are those we cannot guarantee given the uncertain natures of these activities. However, both the baseline and UM together make up our forecasted cost (in the case of Ash Dieback the uncertainty is associated with the ENATS 43-8 unit cost rather than volumes). As with ENWL, if Ofgem continue to reject the proposed UMs we would require the costs associated with these to be reallocated to the baseline. However, before doing so we would ask for further engagement with Ofgem to agree what costs are appropriate to add into the baseline given the risks associated with these uncertain forecasts.

Question ID	Core-Q98.
Question	Do you agree with our proposed assessment approach for Severe Weather 1-in-20 Events?
Response	
We accept the proposed change to the treatment of severe weather 1 in 20 costs as a variant totex allowance. We agree with Ofgem's statement that these events are infrequent and outside a DNO's control which makes it difficult for an accurate forecast of anticipated events and associated costs. We also agree that the proposed change will protect customers and enable DNOs to act accordingly to restore supplies promptly and efficiently. Ofgem should engage further regarding the defined activities that a DNO can recover (as per Core Methodology Section 6.172 and discussed at the SRRWG). As a minimum, and on reflection of Storm Arwen, we would expect that as a minimum DNOs should be able to rightly claim for fault repairs, increased staffing levels (beyond normal operation), mobile generation (beyond normal operation) and welfare costs. This is reflective of the agreement for recovering the costs of Storm Arwen, bar the inclusion of compensation payments. We would also like to see a clear statement on the proposed timeframe for when claims are issued to when they are approved to ensure that claims are managed in a timely manner.	

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q99.
Question	Do you agree with our proposed approach to assessing Inspections and Repair & Maintenance costs?
Associated Evidence	
Title	**Link to Evidence**
Annex 4 - Ofgem Engagement	n/a
Annex 5 - Material Issues	n/a
Annex 10 - North of Scotland	n/a
Response	

We disagree with the approach taken by Ofgem to assess the (CV30) Inspection and (CV31) Repair & Maintenance Costs submitted by each DNO. Our position on this was presented to Ofgem during the Cost & Engineering bilateral held on 28th July 2022 (full details of Ofgem engagement are captured in Annex 4).

Ofgem have used a Modern Equivalent Asset Valuation (MEAV) ratio to benchmark and assess each DNO's proposed costs and volumes. We disagree with this approach for the following reasons:

1) Each DNO is responsible for setting its own policies that determine the inspection and maintenance frequencies of their network assets. These policy driven inspection and maintenance cycles are each DNO's responsibility to determine and reflect the unique mix of asset types that make up their network, each of which have their own I&M requirements. It also reflects the unique age profile of the assets that make each DNOs network which will lead to legitimate differences between the I&M volumes of one DNO when compared to another.

2) Ofgem's MEAV approach only works if each DNO has the exact same inspection and maintenance cycle for each of the asset categories. However, this is not the case and as such the MEAV approach does not account for the variance in policy from one DNO to another and the legitimate reasons each DNO has to vary this policy (such as a different suite of equipment or a different age profile of equipment).

3) Using MEAV to benchmark CV30 and CV31 prevents DNOs from attempting to optimise their totex across the plan given that the opex investment associated with inspections and maintenance have a direct impact of the amount capex intervention that is subsequently required (CV7, CV8, CV9). The MEAV approach pulls DNO back to the lowest inspection and maintenance frequencies without any assessment on the subsequent impact of the capex CV tables (CV7, CV8, CV9 etc.). Furthermore, the relationship between these tables is not suitably covered within the individual disaggregated models, due to the differing techniques used of MEAV in CV30 and CV31 and UR assessment in the other tables.

4) Each DNO has a unique mix of asset models/types on their network, each with their own inspection and maintenance requirements as recommended by the manufacturers. For example, an oil filled circuit breaker has a very different maintenance cycle and cost when compared to a SF6 insulated circuit breaker. However, these are captured in the same CV30/CV31 asset category. It is perfectly legitimate for one DNO to have higher CV30 and

CV31 costs if they have a higher proportion of oil filled circuit breakers on their network than others.

5) CV31 covers both **Repair** & Maintenance cost and volumes. The Repair aspect of CV31 is specific to each DNO and depends upon the number of defects recorded on the network that need to be rectified. Each DNO has its own specific number of defects that require Repair which depends upon the specific mix of asset types they happen to have on their network. As such, the Repair aspect of CV31 is more similar to CV7 given that the volumes depend upon the condition of the assets. This is reactive repair work rather than proactive maintenance.

6) SSEN has a uniquely high proportion of subsea cables on their network compared with other DNOs in the UK. It is not appropriate to compare any other DNO to SSEN in relation to subsea cables volumes or costs under CV30 and CV31. The quantity, average length, age, and the unique marine environment SSEN operates in the North of Scotland significantly influences costs and volumes. Please refer to Annex 5 Material DD Issues and Impact on SSEN for further information.

As such, and with the exception of subsea cables, we propose that Ofgem accepts our proposed CV30 and CV31 volumes and benchmarks each DNO by unit cost only. As described above, our proposed volumes are informed directly by the policy driven inspection and maintenance cycles required for each of our assets and as recorded and tracked via Maximo, our asset management system. For subsea cables specifically, unit costs have been driven by RIIO-ED1 actual costs for CV30 and CV31 related activities and clearly presented in Annex 10 – North of Scotland.

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q100.
Question	Do you agree with our proposed assessment approach for NOCs other?

Response

We agree with Ofgem's approach for Remote Island Generation whereby under section 7.374 Ofgem have stated *"RIIO-ED2 costs are considerably lower for Remote Generation Opex. We consider costs justified so propose to allow submitted costs."* This conclusion is fair, and the approach reflects DNOs specific expertise of running these critical assets that provide necessary network security for islanded customers. However, we note Table 62 of the Core Methodology Document shows a 22% reduction in submitted cost which is counter to the process carried out. We believe this to be a presentational issue aligned with our response in CORE-Q111

We agree with the proposal for Dismantlement for SHEPD; however, since there was no expenditure for dismantlement in SEPD during RIIO-ED1 this has meant that a significant cost adjustment has been proposed for SEPD based on the methodology put forward. Our proposed spend for dismantlement in SEPD is to target redundant sites that pose a significant safety risk due to increased likelihood of trespassing, vandalism, metal theft and unauthorised interference on sites that are not always practical or efficient to inspect (as stated in our A7.1 Safe and Resilient Annex of our final business plan). Due to the safety risk we, the dismantlement costs proposed for RIIO-ED2 should not be impacted by the nominal investment in this category as this is an emerging issue that needs to be addressed.

We do not agree with the approach taken for Substation Electricity as recent world events have triggered significant increases in electricity costs. As such, the costs submitted as part of the final submission are no longer applicable and the proposed methodology is not reflective of this, nor does it enable DNO to adjust costs in line with RPE. The median methodology does not account for the electricity prices in the early part of RIIO-ED1 being significantly lower than the prices seen in the last year; and these prices are anticipated to continue to increase. SSEN has tried to mitigate the uncertainty of electricity price increases by agreeing to a fixed price contract for 3 years from March 2021; however, this means that from March 2024, one year into the new price control, the cost difference is likely to be significant. This has impacted SEPD in particular, as the costs driven by the median methodology are lower than our current fixed priced contract. Ofgem needs to consider the current electricity increases within the assessment of costs as these are not within DNOs' control.

Question ID	Core-Q101.
Question	Do you agree with our proposed assessment approach for Smart Metering Rollout?
Response	
Yes, we agree with Ofgem's approach to benchmarking for Smart Metering Rollout in baseline costs.	

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q102.
Question	Do you agree with our approach to assessing CAI costs?
Associated Evidence	
Title	**Link to Evidence**
Annex 7 – Deliverability	n/a
Cost Assessment Annex F – Scottish Wages	n/a
Annex 10 – North of Scotland	n/a
BPDT update - M25	n/a
Response	

We fundamentally disagree with the approach taken by Ofgem to assess the total CAI costs. The Draft Determination for total CAI reduced spend levels for all DNO groups back to below RIIO-ED1 average spend (figure 1) – **this is insufficient to deliver our RIIO-ED2 plan outputs and meet our legal and regulatory obligations and is clearly not in line with step-change required to deliver net zero.** We consider that the following changes to the cost assessment process for CAIs are required:

1. The use of MEAV as the only cost driver to assess efficient spend for CAI (exc. V&T) costs is unsuitable as it does not explain all costs. RIIO-ED2 has mandated (either via regulatory or legal obligations) that we must undertake new or material increases to activities in ED2 vs ED1 for example, spend in DSO, Environmental (including Flood Mitigation, Losses and Reporting) increases by >350%, RLM increases 950% in ED2 compared to ED1. These require additional Indirect costs to support delivery as described in our Business Plan Annex 12 – Workforce Resilience Strategy. These are not part of the RIIO-ED1 historic cost base and are not explained by MEAV. MEAV, which is calculated using the Total Asset Register, represents only net volume increases (Load) and using a single driver is also a departure from the RIIO-ED1 cost assessment method which used MEAV and Asset Additions as the explanatory variables. It is not clear why a decision to remove Asset Additions from CAI RIIO-ED2 cost modelling has been made given the increase of activity that is not Load related. We will continue to investigate suitable drivers such as Asset Additions in the period up to Final Determinations. This is a key issue with the modelling that needs to be resolved to ensure fair and suitable assessment.

2. As presented to Ofgem at the April 2022 CAWG and during the Cost & Engineering bilateral held on 28th July 2022, the impact of UG cable having an 8x higher weighting than OHL within MEAV distorts the regression analysis for CAI and BSC areas. Indirects are not materially different for the installation of OHL compared to UG cable which we assess as 1.5x UG cable (not 8x) to OHL based on our operational insight. This is significantly lower than the weighting currently given in the modelling. As such, MEAV should be recalculated to reflect the true activity weighting for OH line and UG cable at each voltage level.

3. SHEPD incurs a material level of costs due to our Company Specific Factors for Islands (inc. Subsea) and Sparsity. At RIIO-ED1, Ofgem accepted SHEPD's claim for these factors and substantially accepted the quantified additional costs. At DD Ofgem has rejected all SHEPD's CAI/BSC related Company Specific Factors claim. CAIs and BSCs cannot be fairly assessed for efficiency without pre-modelling adjustments for Company Specific Factors.

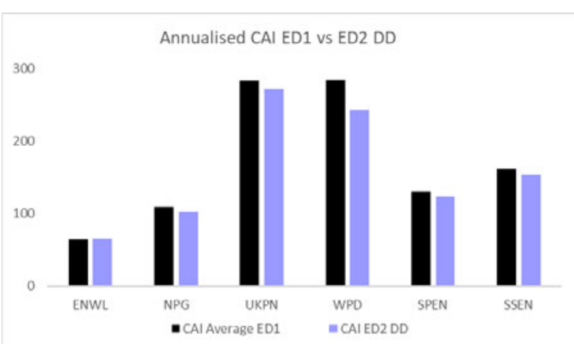
4. Our CAI and BSC submission included Indirect costs to support baseline activities only. CAI costs to deliver our volume driver uncertainty mechanisms are not included in either the cost base or the cost driver (MEAV). These remain essential for UM delivery but are currently unfunded in the DD. We would welcome the opportunity to work with Ofgem and Industry to agree a method (we propose Opex Adjustor per CORE-Q5 and CORE-Q16) to ensure adequate and efficient CAI funding is available for UMs.

5. SSEN is the only company with material costs for Out of Area networks. These costs are not explained by MEAV so should not be treated in the same manner as costs within, for example, "connections out of price control". This has been further impacted by the Net After Non Price Control allocation being applied without using the company specific ratio. As such, Out of Area costs should be fully excluded from cost assessment and for costs that are Non Price Control but included in modelled costs, these should have the company specific ratio applied.

6. For Vehicles and Transport (CAI), using ratio benchmarking with MEAV as a driver over two price controls weights the spend (and activity levels) of efficient spend towards RIIO-ED1. RIIO-ED2 and our Net Zero Obligations bring a step change in requirements for V&T (CAI). We must decarbonise our fleet where it is economical to do so and we must provide vehicles and plant for our increased levels of direct workforce (including trainees) to carry out the increased deliverables. We ask therefore that this is assessed using the Industry Median V&T Cost / MEAV Ratio for the RIIO-ED2 period only.

Reduction to current levels of CAI spend across all DNO groups despite a step change in activity due to Net Zero targets provides an inadequate level of funding for RIIO-ED2.

The DD provides an overall 26% increase (23% SSEN) to capex allowance level across all DNOs compared to average RIIO-ED1 spend. However, the total CAI DD indicative allowances **have decreased by 7%** (5% SSEN) when comparing average RIIO ED1 spend vs RIIO ED2 DD, net before allocation. This brings the Total CAI RIIO-ED2 DDs to below 19/20 average spend levels. This clearly puts at risk key policy outcomes including security of supply, but also the delivery of net zero and reduction in carbon emissions.



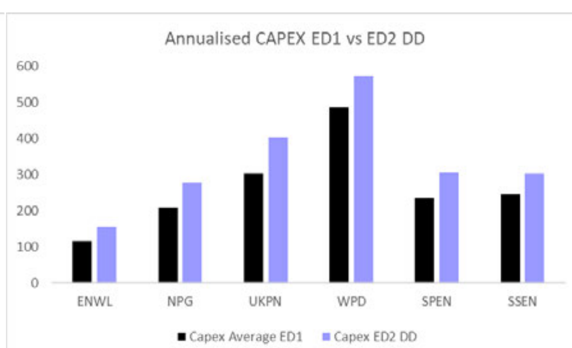


Figure 1: Average Annual CAI Spend in RIIO-ED1 vs RIIO-ED2 annualised DD vs to the increase in Capex RIIO-ED1 vs RIIO-ED2 DD ((7%) reduction in CAI vs 26% increase in Capex).

Our CAI growth table shown in Figure 16.4, section 4.2 of our Business Plan has been aligned with our detailed assessment of new skills required to develop the network in order complete the transition to Net Zero and meet the new baseline expectations for DSO. It is supported by our Business Plan Annex 16.3 Workforce Resilience Strategy, which gives a detailed breakdown of where the skills are required and how we propose to create the capabilities. This is referenced in Annex 7 - Deliverability Annex.

The table at Figure 16.4 in our Business Plan shows that our growth plan was not solely linked to volume. These capabilities and workforce requirements are incremental to our ED1 staffing levels. Growth has been calculated on the basis that system and process efficiencies have been applied and appropriate cost-cutting and skills re-deployment has taken place. We have also assumed a fully productive workforce in operational roles and therefore developed a CAI model to ensure that work flows through to the operational teams to ensure their full productivity. Not fulfilling our CAI model for ED2 will directly affect frontline productivity, and customer and vulnerability service delivery, impacting the activities which support the front-line work, such as flexibility analysis, control room support and system and outage planning. It will also impact on our network protection and inspection and maintenance activities which are vital to ensuring the health of the network. We note that our volumes of work have largely been held at our submitted levels, meaning that the level of indirects to support our direct activities within RIIO-ED2, based on our Regional Operating Models, remains as per our submitted plan.

Our stakeholder engagement activity showed that having sufficient skills to enable the technology and flexibility of options for low carbon future energy scenarios was a key concern for our stakeholders. They also saw it as an opportunity for us to support social mobility and a Just Transition by providing new career routes into the organisation. In preparing our growth model for CAIs we were mindful not only of our stakeholder expectations but also skill development for the electricity network of RIIO-ED3. Our pipelines and new skills training will deliver the next generation of skills as well as those required to meet RIIO-ED2. Growth of our workforce helps us to contribute to the United Nations Sustainable Development Goal of providing decent work and fuelling economic growth.

Vitally, the growth model gives us an opportunity for a real step change in the diversity of our organisation, as all our pipelines and recruitment for growth are actively resourcing for less well-represented groups and better reflection of our diverse customer base. In our most recent pipeline resourcing activity commenced in July 2022 for system planning engineering skills of the future we have achieved 75% diversity.

A reduction to our workforce means that we would risk the following:

a) Developing the new skills and capabilities which are incremental to our delivery in ED1 and must come from a new base, as our work levels in ED1 will not cease or reduce in ED2, and all meaningful skills reassignment and efficiency has already been taken into consideration.
b) Delivering the baseline expectations for DSO; our DSO growth was delineated across the whole SSEN Distribution organisation, not just in our DSO strategy.
c) Delivering our work volumes and outputs as submitted in our business plan.
d) Meeting our stakeholder expectations on skills and career opportunities.
e) Playing our role in accelerating the diversity of the industry as a whole.
f) Supporting the government and the industry in providing long term career pipelines for ED3.

g) Contributing to the growth of the economy in the UK, and the future of the UK as a key source of the energy skills of the next price control.

We also note that the Opex Adjuster UM request was rejected and Ofgem in response to the reverse SQ querying how CAIs for Volume driver UMs will be funded (SSEN011) noted:
“We consider that SSEN is already adequately funded for its indirect costs that may result from the LRE uncertainty mechanisms.”

We strongly disagree with this view – our submitted costs were modelled on baseline deliverables only and MEAV does not include any of the UM volumes and therefore cannot be correctly assessed to include the efficient level of indirects to support uncertainty volume drivers.

There is a clear rational for an OpEx adjustment on volume drivers and we provide further details in our response to SSEN-Q8. The OpEx adjustor method we propose builds on the established precedent from transmission and through re-opener approvals for Green Recovery Mechanism and subsea cables in RIIO-ED1.

The OpEx Adjuster method we propose will ensure DNOs are funded through an automatic mechanism for varying operational costs associated with specific capital investments delivered through volume drivers. It will provide DNOs with OpEx allowances when CapEx allowances are funded through the relevant volume driver and ensures that those OpEx allowances are consistent with those set for baseline allowances.

Our proposed OpEx Adjustor method is a calculated co-efficient that enables Closely Associated Indirect (CAI) spend per £1 of volume driver CapEx to be calculated and applied to specified volume drivers.

This straightforward method enables indirect to be funded for specific volume driver UMs at a level in line with the assessed baseline cost level. This method will ensure DNOs have allowances particularly for volume drivers to enable design, planning and other indirect activities associated with capital delivery which are not part of the unit rate.

We consider the DD cost assessment outcome for CAI is inadequate, particularly when considering that a large percentage of total CAI spend comprises permanent workforce (part of which are in place) and because we have conducted a robust and detailed skills and capabilities assessment which shows that, after efficiencies and re-skilling, we need growth in our people resource to deliver our RIIO-ED2 plan.

For re-openers, the precedent established through the RIIO-ED1 Green Recovery Mechanism and the subsea cable re-opener establishes a clear case to continue to include indirect costs within future re-opener allowance submissions.

This level of funding will result in the same issues occurring in RIIO-ED1 as noted in the 20/21 Network Performance Summary report where Ofgem has commented: *“Five DNO groups have overspent on* *allowances for operational support to date; one of those by 31% […]* ***combined with the tight price control settlement, has made it difficult to achieve cost efficiencies in this category."***

As described in Points 1 to 6 above, we propose the following to address the issues we find in the current CAI modelling:

MEAV as a single cost driver does not explain a material element of RIIO-ED2 CAI or BSC costs:

As part of RIIO-ED2, new activities, which drive growth in our CAIs, are required to be delivered which are either not accounted for by MEAV or only partially accounted for.
For example, our Environment CAPEX spend has increased >300% in RIIO-ED2 vs RIIO-ED1 due to Net Zero obligations including for example an ambitious 1.5° Science Based Target (including losses) requiring at least a 35% reduction in our carbon footprint by 2028 and reducing SF_6 emissions from our assets by a minimum of 35%, report on and begin to reduce our holdings.
This will result in increased operational activity to deliver which will require both CAI and BSC support but has no impact in MEAV as our Asset Register total will remain unchanged. Other areas that see a material increase in work with no reflected change in MEAV, are OHL Clearance, RLM, Tree Cutting, DSO and Vulnerability. The key issue here is throughout the DNOs plans there are differences in spends due to legitimate reasons, yet no explanatory driver to account for them within the regression modelling.

Additionally, particularly for DSO, the levels of spend in RIIO-ED2 will be variable across DNOs due to implementation maturity and strategy.
For example, in the Business Plan Guidance for RIIO-ED2 for DSO, Ofgem have set a number of baseline expectations for DNOs in terms of the DSO capabilities they need to deliver. We welcome this clarity which has enabled us to form clear and cost-effective delivery plans informed by ED1 innovation (e.g. Project LEO) and collaboration (e.g. Open Networks, RDPs). Nevertheless, although ED1 has seen great progress in many of these areas it would not be appropriate to benchmark our ED2 approach against ED1 requirements and outcomes. Many of the DSO baseline expectations are new or a step-change to ED1 requirements and will need funding to ensure they deliver both for consumers and the wider net zero goal. The Draft Determination states:

> *"We propose to accept the majority of the DNOs' DSO strategy proposals without amendment. Broadly speaking, DNOs have articulated the DSO transition issues prevalent in the DNO's region and have put forward coherent proposals to address them in RIIO-ED2."*

The overall cut to CAIs, where the majority of DSO spend sits, would seem to counter that. The cost assessment approach of using RIIO-ED1+ED2 with MEAV will not enable this significant new spend in RIIO-ED2 to be properly assessed particularly given these activities are not represented in the MEAV driver as DSO should enable the avoidance of reinforcement spend.

In RIIO-ED1 this issue was partially resolved by using two cost drivers, MEAV and Asset Additions. This second cost driver explained costs that were required but would not result in an increase to the asset register. It is not clear why a decision to remove Asset Additions from CAI RIIO-ED2 cost modelling has been made given the increase of activity that is not Load related. We will continue to investigate suitable drivers such as Asset Additions in the period up to Final Determinations. This is a key issue with the modelling that needs to be resolved to ensure fair and suitable assessment.

MEAV cost driver weighting errors:

While we consider the use of MEAV appropriate in other areas, the calculation of MEAV is inappropriate for CAI and BSC, Property and Vehicles and Transport. OHL and UG cables have a similar indirect resource implication in terms of 'back office' functions and thus should have equal weighting in MEAV. However, in the MEAV calculation, UG cables can be over eight times more expensive than OHL.

Our own assessment using SEPD operational data shows that only two areas of Core CAIs / BSC would require higher costs when delivering UG Cable works vs OHL:

1. Using our Cost, Time, and Resource (CTR) Catalogue, the design time for 10km of UG Cable compared to design of up to 5km OHL when compared per km is equal for both UG cable and OHL.
2. We assessed the Indirect Resource required to carry out 1km of LV Cable Overlay vs LV OHL ABC Mainline Construction. Our analysis shows that for this category, 4x the resource is required, and this ratio is applicable for all voltage levels. This relates to aspects of costs in CAI Project Management and CAI EMCS only.
3. All other categories are like for like when comparing UG cable vs OHL including Network Policy, Control Room, System Mapping, Call Centre, Stores, Operational Training, Wayleaves, Vehicles and Transport and all BSC categories.

No category incurs an 8 x increase in effort in indirects to deliver UG cable vs OHL works and most Indirect categories are like for like effort irrespective of UG cable / OHL delivery. Furthermore, some of the increased costs associated with delivery of UG cable are due to clerical aspects of street works which are treated as a company specific factor for DNOs that are heavily weighted towards underground cable.
When assessing the total impact of Design and Asset replacement work for OHL vs UG cable for CAI and BSC cost total, the activity ratio is 1: 1.5 and as such, MEAV should be recalculated for to reflect the true activity weighting for OHL and UG cable which we assess as 1.5x UG cable vs OHL (significantly below the 8x). Other suitable cost drivers that reflect operational implications may also be available and should be tested. See Cost Assessment Annex E - Review of the cost assessment in Ofgem's RIIO-ED2 Draft Determinations.

Company Specific Factors for SHEPD must be accounted for:

For SHEPD, we disagree with the Draft Determination for our Company Specific Factors (Sparsity and Islands) along with the assessment of Regional Wages – please refer to our Annex 10 North Of Scotland and resubmitted M25 which demonstrates the actual spend in RIIO-ED1 on our Company Specific Factors is in line with our RIIO-ED2 assessment.

Net after Price Control Allocation must be based on company ratio:

The Non Price Control allocation for Net after Allocation is required to be adjusted to reflect the ratio of in / out of price control CAIs post cost assessment. We disagree with the current adjustment within the PCFM interface file which removes the full pre cost assessment value from the indicative allowances and this should be based on the Net before Allocation to Net After Allocation ratio.

Out of Area CAI costs should be excluded from cost assessment:

SSEN has included Out of Area CAI costs within CAI (C9) table and so are included in the cost assessment as these are an adjustment after the Net Before Allocation value (which is used for cost assessment) per the BPDT guidance. SSEN is unique in terms of scale to any other DNO with around £22m of costs with no corresponding MEAV. As these costs do not form part of SSEN MEAV, it is an error to include them as part of our Net Before Allocation cost base; these should be excluded from cost assessment.

Vehicles and Transport as part of delivering Net Zero cannot be accurately assessed using RIIO-ED1 data:

SSEN is committed to decarbonising 100% of fleet under 3.5tn and 50% of fleet over 3.5tn by 2030 as part of our EAP contributing towards Net Zero. Additionally, in line with our deliverability and workforce strategies, the increase in volumes of work in RIIO-ED2 impacts the direct workforce which is forecast to grow by 290 Whole Time Equivalent (WTE) over the RIIO ED2 period along with an increase in trainees. This will therefore mean a larger operational fleet for our workforce with the additional requirement of decarbonising our fleet where this is economical to do so. Moving to EVs as our leases expire means that whilst we have embedded efficiencies within our request due to our operational regional model, this does not enable us to fully mitigate the increased vehicle cost requirements of RIIO-ED2.
Linked to Point 1, MEAV does not represent the increased level of activity for areas other than Load and therefore combining MEAV and heavier weighted 8 years of ED1 data, decreases the operational fit of this model.
The approach of using RIIO-ED2 data only for ratio benchmarking has been applied to other tables (e.g. secondary reinforcement, diversions, smart metering) and we believe it is appropriate here.

Volumes of work and EV Environmental targets mark a fundamental change from RIIO-ED1 and therefore it is our view that Vehicles and Transport should be assessed using RIIO-ED2 time period only.

Question ID	Core-Q103.
Question	Do you agree with the proposed assessment approach for Business Support costs?
Associated Evidence	
Title	**Link to Evidence**
Cost Assessment Annex E	n/a
Annex 10 - North of Scotland	n/a
Cost Assessment F	n/a
Response	

We disagree with the approach taken by Ofgem to assess the total business support costs (BSC). Linked to our response to CORE-Q102, the regression modelling approach for both CAI (exc. V&T) and BSC has produced a modelled efficiency that is not aligned with the operational requirements of indirect costs needed to properly deliver the step change in our RIIO-ED2 plan.

1 Ofgem has departed from its previous RIIO-ED1 approach without additional justification: both Core Business Support and IT&T have been assessed at licensee level in ED2 as opposed to company-level which was the RIIO-ED1 methodology. A licensee-level assessment is not reasonable in the context of either of these categories, as it is not representative of how we operate our IT systems or corporate support from a cost perspective. Therefore, these costs must be assessed at company level in line with the approach taken in RIIO-ED1.

2 As presented to Ofgem at the April 2022 CAWG and during the Cost & Engineering bilateral held on 28th July 2022, the impact of underground (UG) cable having an 8x higher weighting than overhead line (OHL) within MEAV distorts the regression analysis for CAI and BSC areas. Indirects are not materially different for the installation of OHL compared to UG cable, which we assess as 1.5x UG cable vs OHL (vs the current 8x) based on our operational insight. This is significantly lower than the weighting currently given in the modelling. As such, MEAV should be recalculated to reflect the true activity weighting for OHL and UG cable at each voltage level.

3 SHEPD incurs a material level of costs due to our Company Specific Factors for Islands (including subsea) and sparsity. At RIIO-ED1, Ofgem accepted SHEPD's claim for these factors and substantially accepted the quantified additional costs. At DD Ofgem has rejected all SHEPD's CAI/BSC related Company Specific Factor claim. CAIs and BSCs cannot be fairly assessed for efficiency without pre-modelling adjustments for Company Specific Factors (see our North of Scotland Annex).

4 IT&T has been assessed for RIIO-ED1 & ED2 period combined despite ED2 having extra unique challenges that are not accounted for via any pre-modelling adjustments. We do not agree with the use of RIIO-ED1 & ED2 due to the significant step change in investment that we are required to make to deliver our Digital and Data strategies. Therefore, these costs must be assessed at company level and the period of assessment for IT&T should only be RIIO-ED2 to reflect the scale of change in requirements.

5 Combining Non-Operational Property and Property BSC costs together is an unexplained and unjustified departure from the RIIO-ED1 cost assessment methodology. Capex property spend is lumpy and atypical in nature and is an area where it should not be expected that DNOs spend profile over a price control would align. We request that Property Management (BSC) and Non-Operational Property costs are assessed separately.

6 SSEN is the only company with material costs for Out of Area networks. These costs are not explained by MEAV so should not be treated in the same manner as costs within for example “connections out of price control”. This has been further impacted by the Net After Non Price Control allocation being applied without using the company specific ratio. As such, Out of Area costs should be fully excluded from cost assessment and for costs that are Non Price Control but included in modelled costs, these should have the company specific ratio applied.

Core Business Support Costs

The Draft Determination provide a 26% increase (23% SSEN) to capex allowance level across all DNOs compared to average RIIO-ED1 spend. Counterintuitively, the Total CAI DD indicative allowance **has decreased by 9%** (3% SSEN) as shown in figure 1 below (comparing average annual RIIO ED1 spend vs RIIO ED2 DD net before allocation).

This reduces our indicative RIIO-ED2 allowance to below 19/20 spend levels **– this is insufficient to deliver our RIIO-ED2 plan outputs and meet our legal and regulatory obligations.**

Figure 1: Core BSC annualised average ED1 spend vs ED2 DD by DNO group.

MEAV as a cost driver does not account for all RIIO-ED2 activities:

As part of RIIO-ED2, new activities which drive growth in our BSCs are required to be delivered which are either not accounted for by MEAV or only partially accounted for, e.g. BSC costs for DSO, enhanced Customer & Vulnerability, increase in Procurement function for Supply Chain management). For example, in 5.36 of the DD Core Methodology document, Ofgem notes that *“Ensuring energy companies support and protect consumers in vulnerable situations is a priority for Ofgem. Our RIIO-ED2 methodology supports network companies to deliver the key vulnerability priorities associated with the DNOs’ activities to protect those whose wellbeing is most at risk during a loss of supply and to help those in, or at risk of, fuel poverty.”*

However, the cost assessment of Core Business Supports for RIIO-ED2 reduces spend levels to areas which include key elements of this plan, such as fuel poverty, partnership funding and training.
For example, for DSO, in the final iteration of the Business Plan guidance Ofgem requested specific measures to mitigate against perceived conflicts of interest. SSEN has included costs in core business support to include business separation with staff training and new business procedures. This is a completely new approach and cannot be benchmarked against ED1. Neither of these new/ increased activity levels are explained by MEAV as a driver.

MEAV cost driver weighting errors:

As per our response in CORE-Q102, while we consider the use of MEAV appropriate in other areas, the calculation of MEAV is inappropriate for Indirect areas of spend (CAI/BSC/ V&T and Property). OHL and UG cables have a similar BSC cost requirement, and thus should have equal weighting in MEAV.

Our own assessment using SEPD data to represent an average profile of UG cable / OHL, shows that only Core CAIs would require additional effort associated with UG cable vs OHL but not 8x the level which the use of MEAV implies. All other categories are like for like when comparing UG Cable vs OHL including Business Support Costs. Our analysis shows that a ratio of 1: 1.5 OHL vs UG cable is required for Indirect support. As such, we propose that MEAV should be recalculated for this category using a 1.5x weighting (rather than 8x) for Underground cable vs OHL at each voltage to reflect activity. See Cost Assessment Annex E - Review of the cost assessment in Ofgem's RIIO-ED2 Draft Determinations for further detail.

IT & Telecoms:

In line with our response to CORE-Q79, whilst we agree that assessing IT & Telecoms BSC together with Operational and Non Operational IT Capex is appropriate, we disagree with the cost assessment methodology for the reasons outlined below.

Ofgem has departed from its previously signalled approach without additional justification: IT&T BSC has been assessed at licensee level in ED2 as opposed to company-level in ED1. A licensee-level assessment is not reasonable in the context of IT&T, as it is not representative of how we operate our IT systems from a cost perspective. In addition, IT&T has been assessed for ED1 & ED2 period combined despite ED2 having extra unique challenges that are not accounted for via any pre-modelling adjustments. As noted in the Core Methodology Document: *Compared to the other categories, IT & Telecoms costs entail a high level of fixed costs. Moreover, these costs are expected to increase substantially over RIIO-ED2 due to investments in data and digitalisation." – P345.*

Therefore, these costs must be assessed at company level and the period of assessment for IT&T should only be ED2 to reflect the scale of change in requirements as noted in the Core Methodology Document: *Compared to the other categories, IT & Telecoms costs entail a high level of fixed costs. Moreover, these costs are expected to increase substantially over RIIO-ED2 due to investments in data and digitalisation." – P345.*

Property Management:

We do not agree that assessing Property Management BSC and Non-Operational Property together is appropriate and we have concerns as raised in BSC with using MEAV as a driver for this area in its current form.

Combining Non-Operational Property and Property BSC costs together is a departure from the RIIO-ED1 cost assessment methodology. Capex property spend is lumpy and atypical in nature and is an area where it should not be expected that DNOs spend profile over a price control would align. Assessing Capex spend with Property Management Business Support cost looking at a relatively short time period when considering property spend profile (and including COVID impact of periods where construction was closed) does not make intuitive or operational sense as the two spends are not well linked. We request that Property Management (BSC) and Non-Operational Property costs are assessed separately

As described above in Core BSC and CORE-Q102 and presented to Ofgem at the April 2022 CAWG and during the Cost & Engineering Bilateral held on 28th July 2022, the impact of UG cable having an 8x higher weighting than OHL within MEAV distorts the regression analysis for CAI and BSC areas. Indirects are not materially different for the installation of Overhead Line compared to Underground Cable which we assess as 1:1.5 OHL / UG Cable based on our operational insight. This is significantly lower than the weighting currently given in the modelling. As such, MEAV should be recalculated to reflect the true activity weighting for OH line and UG cable at each voltage level. See Cost Assessment Annex E - Review of the cost assessment in Ofgem's RIIO-ED2 Draft Determinations for further detail.

Company Specific Factors:

For SHEPD, across all BSC categories we disagree with the Draft Determination for our Company Specific Factors (Sparsity and Islands) along with the assessment of Regional Wages – please refer to our North of Scotland Annex and resubmitted M25 which demonstrates the actual spend in RIIO-ED1 on our Company Specific Factors is in line with our RIIO-ED2 assessment. See Annex 10 – North of Scotland Draft Determination Response and Cost Assessment F.

Net after Price Control Allocation

The Non Price Control allocation for Net after Allocation is required to be adjusted to reflect the ratio of in / out of price control CAIs post cost assessment. We disagree with the current adjustment within the PCFM interface file which removes the full pre cost assessment value from the indicative allowances and this should be based on the Net before Allocation to Net After Allocation ratio.

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q104.
Question	Do you agree with our approach to assessing street works costs?
Associated Evidence	
Title	**Link to Evidence**
Annex 5 – Material Issues	n/a
Response	

We accept the general approach to assess Street works in RIIO-ED2 using a growth driver based on volumes of work and historic costs.

As noted in the Core Methodology document: *"Street works costs have historically impacted DNOs differently due to local authorities having introduced permit and lane rental schemes at different rates, leading to some DNOs operating in regions that are more heavily permitted than others."* As this is a risk outside DNOs' control and will continue to be one in RIIO-ED2, we support the continuation of a re-opener mechanism as per the response provided by Ofgem to our reverse SQ SSEN012:

"Our position in SSMD to retain the ED1 Street works reopener (Annex 2, Table 4 p65) is unchanged, and the licence condition for this re-opener is still under development, having been briefly discussed at the Cost Assessment Working Group (CAWG) Uncertainty Mechanisms workshop on 19 May 2022 and brought to the Licence Drafting Working Group (LDWG) on 8 June 2022 for discussion."

Within the re-opener we ask that Ofgem takes account of the management of costs associated with implementing Environment Agency Guidance RPS 211 (Excavated waste form utilities installation and repair). In Annex 17.1 of our final business plan submission, pages 93-94 we set out a proposal for adapting the scope of the Street works re-opener to accommodate. We welcome Ofgem's response to our reverse SQ SSEN012 on this and look forward to working with Ofgem on implementation:

"LDWG, we propose to retain the existing condition and add a provision to the definition of street works costs (similar to the provision within RIIO-GD2) so that street works costs for RIIO-ED2 will include "costs arising from changes to the requirements imposed on the licensee in respect of the disposal of street works excavation waste material", to manage those relevant costs related to RPS211."

We note that Permit Conditions is an area that is increasingly disparate between DNOs (ranging from £0m to £26m per DNO (making up a third of the gross total cost submitted for Street works in RIIO-ED2. As this comprises of *"incremental costs of undertaking works resulting from permit conditions, e.g. a requirement to work at non-peak time"* per the BPDT Glossary, we have reservations in the precedent to assessing these types of incremental costs based on growth driver and historic costs. This may not be appropriate due to the risk of this exclusion impacting industry averages for disaggregated modelling in certain tables such as faults, given that there is likely to be different cost capture methodologies for incremental costs across DNOs rather than this being solely the result of different levels of activity.

Lastly, as noted in our Annex 5, there is an error in this model where the share of out of price control costs is included erroneously in Connections (in price control) rather than being excluded as an out of price control costs

Question ID	Core-Q105.
Question	Do you agree with our proposal to carry out a demand driven post modelling adjustment?
Associated Evidence	
Title	**Link**
BPDT update: M20 Table	n/a
Annex 2 – Outputs Summary	n/a
Annex 11 - Load UM	n/a
Response	

We agree in principle with the need for a demand driven adjustment, particularly given the lack of consistency across DNO approaches to forecasting load in the context of the business planning guidance for RIIO-ED2. However, we have two issues with how it is applied: one serious issue relating to the numbers used in calculating how it applies to SSEN; and the other being a matter of principle regarding the areas of totex to which the adjustment is applied.

The first issue is concerned with the LCT numbers used by Ofgem in the demand-driven adjustment. This issue is significant, with a variance in the order of £100m.

As part of our consideration of the detail of the Draft Determination, it has become clear that the LCT numbers in neither the original M20 table, nor the subsequent SQ response, correctly reflect the LCT numbers which underpin our LRE proposal. This has led to a material variance in the calculation of the 'demand driver adjustment'. The overstatement of EV and HP numbers for SSEN has led to a large (£144m) reduction in DD totex, which is incorrect.

Memo table M20 set out EV and Heat Pump volumes for the ED2 period. A subsequent Ofgem SQ (SSEN083) sought clarification on the forecast LCT numbers and requested the provision of additional information to improve the consistency of reported items across DNOs. SSEN provided a response to this SQ on 16th February 2022.

Ofgem should recalculate the demand-driver adjustment based on the revised LCT numbers provided below. These align with our baseline LRE proposal (£350m*).

An updated version of M20 (as per the previous Ofgem SQ) with the correct LCT numbers is attached.

Detail

Our LRE plan is based on the DFES ST scenario (2020), with a comparatively small, additional, amount (£23m) of strategic investment (Cat.2 expenditure in Years 1 and 2) to ensure that future net zero pathways are not foreclosed. This enabled us to be prepared – both in terms of organisational and delivery capability and network capability – to meet the requirements of more demanding net zero scenarios (such as CT) eventuating and the uptake in EVs and HPs being higher than is provided for in our ex-ante baseline ask.

The strategic spend (£23m) mostly (93%) provides for secondary (HV and LV) works). Not having this allowance would mean that if CT transpires in Year 1, customers would experience delays in getting LCT connected due to the lead time for secondary works (typically 1-2 years). By having this funded upfront, we would be able to do this work in advance (in Year 1), and then continue to do it in Year 3 through UM funding. Not enabling this will lead to a 1-2 year delay for some customers wanting to connect EV chargers and HP – leading directly to avoidable consumer cost and unnecessary delays to achieving Net Zero. This also puts the delivery of our stakeholder led outputs at risk as detailed in Annex 2.

The practical application of this approach means that peak demand is assessed and compared under CT at the end of ED2 Year 2 (CT2) and under ST at the end of Year 5 (ST5). Our plan is based on identifying and relieving capacity constraints based on the highest of CT2 and ST5 at each point in the network. The corresponding LCT numbers, therefore, are the highest of CT2 or ST5. This does not align with the numbers previously submitted in the M20 SQ and subsequently used by Ofgem in the demand-driver adjustment.

We have now undertaken a revised assessment for both the SHEPD and SEPD licensed areas, for EVs and heat pumps, and used these numbers to provide a further update to the M20 table.

These revised LCT numbers (and associated MW), are much closer to those used by Ofgem as the basis for the demand-driver adjustment. It was the significant £144m reduction applied in DD to align LCT figures to the ST view that raised the question of why our plan has been subject to a comparatively large demand-driven adjustment – given (almost) the same scenario choice (save for £23m – see above).

We provide examples below to illustrate the issue described above. Figure 1 shows the total EV (MW) under each scenario in the SHEPD licence area. Under the methodology we have used to determine LRE, as described above, the number of EV (MW) is the higher of 298 (CT2) and 356 (ST5), 356 is the correct number to be used in the demand-driven adjustment to align with our baseline LRE ask. This is shown in the green box in Figure 1.

The red box shows the Year 5 figure of 505 previously advised in the M20 update SQ. This was determined by taking CT2 number of 298 and making annual additions. This does not align with the baseline LRE plan and should not, therefore, be used in the demand-driven adjuster as this significantly overstates the number of EVs when considering what the baseline plan assumes by way of EV uptake.

	Y1 2024	Y2 2025	Y3 2026	Y4 2027	Y5 2028
SSEH EV ST	116	149	217	283	356
SSEH EV CT	215	298	449	606	761
SSEH EV Submitted	215	298	365	432	505
SSEH EV LRE Proposal	116	149	217	283	356

CT (Y2) plus ST (Y3-5) additions

Worst case of CT (Y2) or ST (Y5)

Figure 1 – EV chargers SHEPD (MW)

Figure 2 shows the case of heat pumps in the SEPD licence area. This time the 'correct' number to use is 222,453 (CT2), as this is higher than the ST5 number of 154,653. The number of 287,342 was the M20 SQ submitted number and again overstates the number of heat pumps and does not align with the baseline LRE plan.

	Y1 2024	Y2 2025	Y3 2026	Y4 2027	Y5 2028
SSES HP ST	75,046	89,764	104,630	129,476	154,653
SSES HP CT	174,578	222,453	287,447	382,686	477,645
SSES HP Submitted	174,578	222,453	237,319	262,165	287,342
SSES HP LRE Proposal	146,359	165,383	184,406	203,430	222,453

CT (Y2) plus ST (Y3-5) additions

Worst case of CT (Y2) or ST (Y5)

Figure 2 – heat pump numbers in SEPD

Figure 3 compares total (SHEPD and SEPD) EV charger MW and heat-pump numbers between previously submitted LCT numbers ('M20 as submitted by SSEN in SQ (Feb 22)' and those which correctly align with our LRE baseline plan ('LCT# as per SSEN LRE baseline'). The charts also include Ofgem ST reference numbers used as the basis for adjustment in the demand driver adjuster ('Ofgem ST (SSEN) as per Demand-Driver adj.'), and also the numbers according to the most recent DFES ('Ofgem ST (SSEN) estimated FES 22 impact').

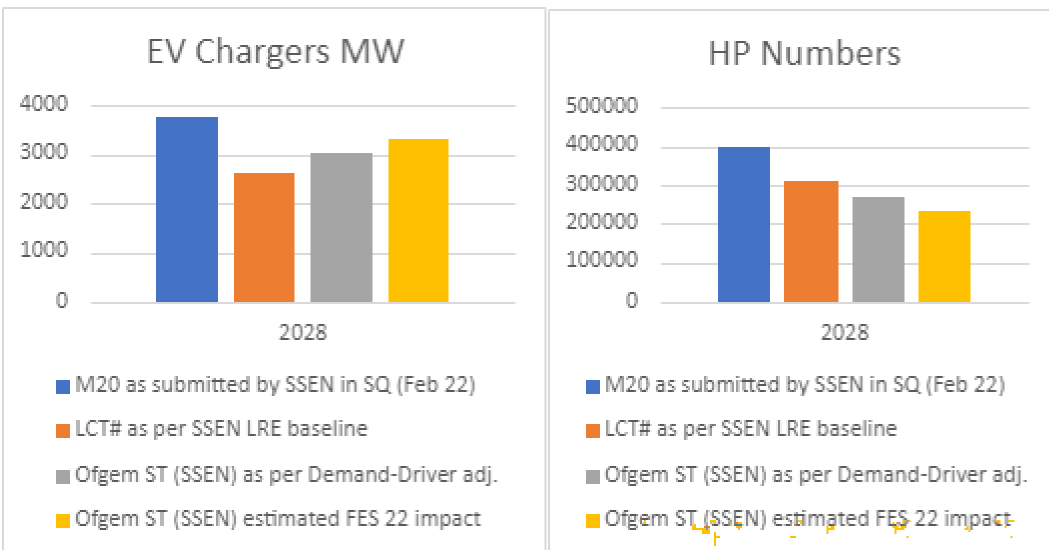


Figure 3 – Comparison of 'submitted' and 'updated' total (SSEN) EV charger and heat pump numbers

For the avoidance of any doubt, neither the numbers submitted in the original M20 table, nor those provided in the subsequent SQ update, have been used in preparation of the business plan load-related expenditure proposal. The exercise to complete these tables was separate to the load modelling. Had we known that M20/SQ LCT numbers were to be used as the basis for large adjustments to our overall totex proposal, then we would have sought further Ofgem guidance on completing the tables.

Ofgem should recalculate the demand-driver adjustment based on the revised LCT numbers provided in the associated spreadsheet. These align with our baseline LRE proposal (£350m*).

Our second issue – which is separate from the first one, concerns the 'presentational' issue and challenge associated with the demand-driver adjustment appearing to have been applied to the entire totex portfolio, when the underlying driver for the adjustment is LCT numbers. For the majority of our totex proposal cost items, there is no direct correlation with LCT uptake. Given that the remaining totex is broadly invariant to load, we suggest that Ofgem allocates this adjustment to LRE only to ensure a more accurate and appropriate representation of modelled costs.

Ofgem's approach in making this large top-down adjustment – which is previously untested – results in significant additional cuts which further put net zero at risk and take the level of investment below what is required to ensure our plan is net zero compliant, in line with Ofgem's own guidance and our stakeholders' feedback.

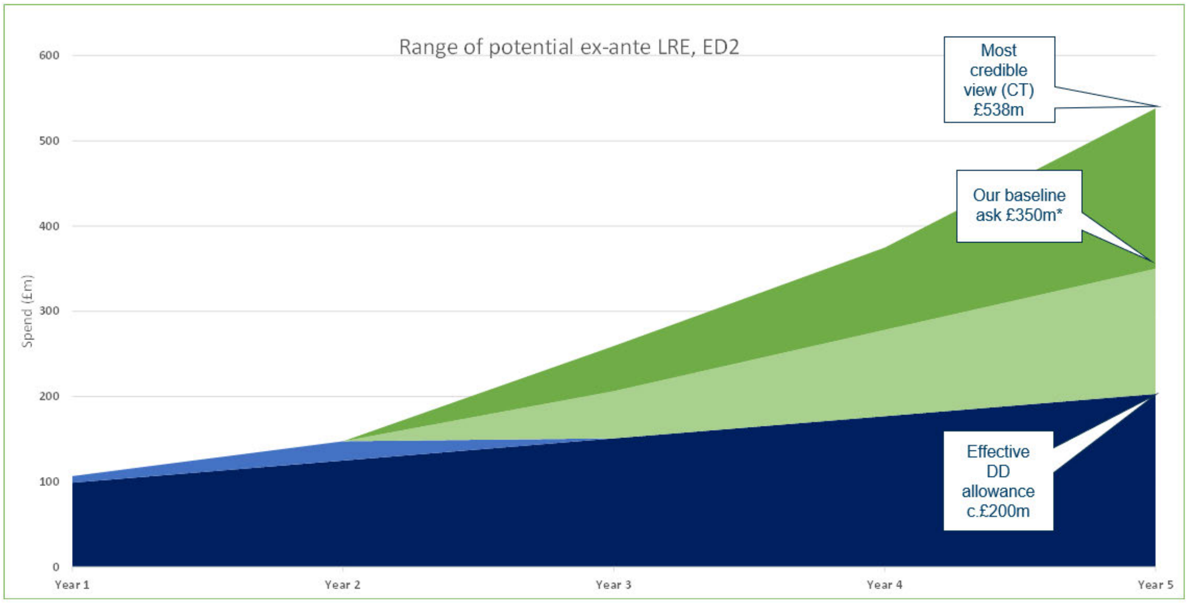


Figure 1 - A large additional cut to LRE moves our baseline plan to net zero non-compliant

** includes £52m of highly likely UM expenditure – as per Ofgem normalisation adjustment*

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q106.
Question	Do you agree with our proposal to not carry out any Quality of Service based adjustments?
Associated Evidence	
Title	**Link**
Annex 2 – Outputs Summary	n/a
Response	

As a starting point, we consider that DNOs should be funded to deliver baseline levels of target. We consider this position to be in line with Ofgem's own policy as stated in its Design Principle 3 for RIIO-ED2: "*As a general rule, the delivery of a target level of outputs should be funded through baseline allowances, rather than through incentives. Target levels should be set so that the benefit to consumers of achieving target levels is broadly balanced by the cost in higher network charges.*"

We note Ofgem's view that it "*does not set specific ex ante allowances for Quality of Service (QoS). Instead DNOs receive financial incentive if they perform well against their Customer interruptions (CI) and Customer Minutes Lost (CML) targets set under the IIS.*" We set out our position on the IIS in response to CORE Qs 44-49.

There is a clear trend towards increasing customer expectations, as set out in the extensive stakeholder engagement we carried out in our plan and reflected in the stretching targets we set in our plan.

This forms part of the wider debate regarding the extent to which companies in regulated sectors should be funded to deliver against more challenging performance targets supported by customer and stakeholder evidence.

In the PR19 water appeals, the four appellants argued that there was a cost–service disconnect in Ofwat's PR19 framework whereby service improvements were being set without consideration of the costs required to achieve those improvements.

Whilst the CMA did not attempt to model this cost/quality relationship or update its base cost models in its Final Determination, it did strongly support the operational principal that efficient companies will require more expenditure to improve some outcomes. For example, the CMA concluded that, "*there is a link between maintaining higher performance on leakage and costs such that the base cost model we used will not adequately compensate all companies that are maintaining performance above the upper quartile [...].*" And ... "*that further enhancement allowances were needed to meet the ambitious leakage performance commitments.*"

As a result of this view, the CMA increased the base allowances for one appellant to reflect the cost associated with maintaining high leakage performance. The CMA also made an enhancement allowance for three of the appellants to reflect the costs associated with improving their leakage performance.

Given the important precedent set by the CMA demonstrating there is a clear operational cost / quality relationship, Ofgem must ensure that it adequately funds more stretching service quality targets for companies through a clear and identified increment to allowances.

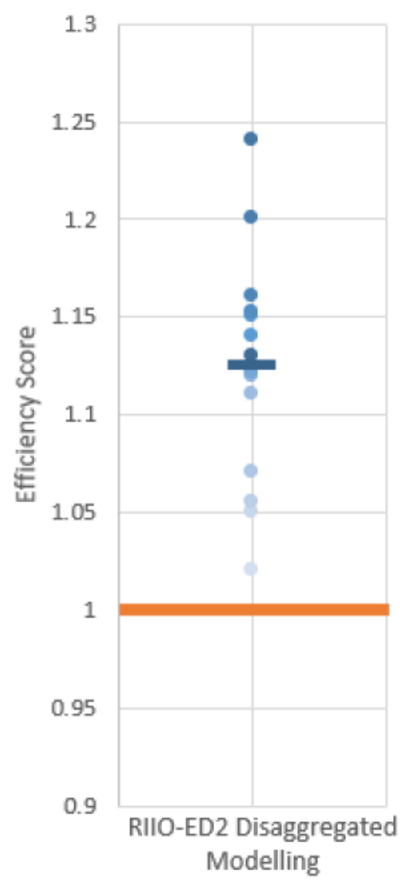
This is of particular importance given the significant cuts that Ofgem has applied across our plan, including in critical areas such as enabling digitalisation spend. We have clearly outlined the impact that Ofgem’s cuts will have on our stakeholder-led outputs in Annex 2. We note that Ofgem is also looking to review standards in a number of areas including resilience and connections. In this context Ofgem must consider the impact of any future changes to standards and outputs on costs.

Question ID	Core-Q107.
Question	Do you agree with our approach to combining our totex and disaggregated benchmarking models?
Associated Evidence	
Title	**Link to Evidence**
Cost Assessment Annex E	n/a
Response	

We disagree with Ofgem's approach to combining the totex and disaggregated benchmarking models. There is a fundamental error in the efficiency applied from the disaggregated model in that the inconsistency between totex and disaggregated model application results in artificially lower final allowances.

Disaggregated efficiency benchmark

The disaggregated modelling output shows efficiency scores that exceed 1 for all DNOs, implying that no DNO is deemed as efficient per the Ofgem derived models. This is illogical as for a fair and relevant modelling suite you would expect frontier DNOs to exceed the model efficiency. The models are not appropriately calibrated, and do not consider the trade-offs between cost tables, which is incorrectly classified as inefficiency as referenced by Ofgem in para 7.438. Below is the range of disaggregated efficiency scores as calculated by Ofgem in the Draft Determination with the median of all scores shown as a bar:



The approach Ofgem utilised within Draft Determination assumes that the output of the model is reflective of an efficient DNO, by using the calculated efficiency score as the adjustor to submitted costs, before combination with the separately calculated totex efficient view. Therefore, it assumes that the output of the disaggregated modelling when individually added up is reflective of an efficient company.

As noted with regard to the choice of disaggregated benchmarking "*All companies are currently facing an efficiency challenge under disaggregated modelling [..] That is, the catch-up benchmark is being set beyond current best practice to a hypothetical position that no DNO currently achieves.* ***This runs counter to regulatory precedent and the purpose of comparative efficiency analysis*** *(whereby inefficiency relative to current best practice is identified).*" Cost Assessment Annex E - Review of the cost assessment in Ofgem's RIIO-ED2 Draft Determinations:

Ofgem should use the median of the disaggregated efficiency scores to determine the appropriate benchmark to be applied. This would ensure that the modelling is reflective of the actual performance of DNOs, and not based upon a notional DNO that over assumes trade-offs and efficiencies. As per Ofgem's comments the use of median would be appropriate as by the design of disaggregated assessment there is already an implied challenge built in. For clarity, as the median efficiency challenge of the Draft Determination is c.1.126, this should be the benchmark. The worst performing DNO at Draft Determination had a disaggregated efficiency challenge of 1.24, therefore the appropriate challenge should be 1.114 which brings the DNO back to the median level of disaggregated assessment.

Model Weighting

Whilst we agree with Ofgem's approach to applying equal weight between the totex and disaggregated modelling – we disagree with the equal weighting applied across the three totex models.

The reason for our disagreement is that totex model 1 is different in its specification from models 2 and 3. Model 1 has a bottom-up CSV (and relies only on a CSV). By contrast models 2 and 3 are top-down CSVs extended to include capacity released and a composite LCT uptake variable.

As such models 2 and 3 should be seen as alternative top-down totex models and model 1 as a bottom up totex model.

Consequently, we believe a more robust weighting of these models would be to place an equal weighting on bottom-up /top-down modelling – this would be achieved a by placing 50% weighting on model 1 and a 25% weighting on both models 2 and 3.

Question ID	Core-Q108.
Question	Do you agree with our approach to setting and applying the efficiency challenge using a glide path between the 75th and 85th percentile over a 3-year period?
Associated Evidence	
Title	**Link to Evidence**
Cost Assessment Annex E	n/a
Response	

We fundamentally disagree with both the setting and application of the efficiency challenge. Ofgem has chosen to take a very aggressive stance in setting the ED2 efficiency frontier without the necessary evidence to support such a position.

Ofgem's decision to apply a glide-path from the 75th to the 85th percentile lacks coherent justification. The justifications brought forward by Ofgem are both misleading and fail to fully take in to account the differences between the GD2 and ED2 price controls. In summary our disagreements with this approach are:

- The glide-path to the 85th percentile is introduced to ensure consistency with the methodology used in RIIO-GD2. However, we do not think this is sufficient justification in this context. This is because the model quality in ED2 is markedly lower compared to GD2 (the average adjusted R-squared is 0.84, as opposed to 0.93 in GD2). Moreover, uncertainty and issues related to the collection of new data in new areas, potentially affecting data quality, also point clearly towards the need for a more cautious approach.
- The impact of this change appears to be markedly more material than what was estimated in RIIO-GD2, having risen on average to 0.7% of baseline allowance.
- Lastly, Ofgem argues that after two price reviews under totex-based models, differences in cost performance revealed through benchmarking can be attributed to genuine differences in efficiency. However, the opposite could also be argued, as the catch-up dynamic could be argued to become less relevant (and thus less stringent) over time, as efficiency gains progressively shift to ongoing efficiency.

Further detail and supporting evidence are set out in section 5 of Cost Assessment Annex E, Oxera - Review of the cost assessment in Ofgem's RIIO-ED2 Draft Determinations.

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q109.
Question	Do you agree with our proposed RPEs allowances? Please specifically consider our proposed notional cost structure, assessment of materiality, and choice of indices in your answer.
Associated Evidence	
Title	**Link to Evidence**
Cost Assessment Annex A	n/a
Response	

We disagree with the proposed RPE allowances and Ofgem's approach includes material errors. Commissioned by the ENA, a third-party consultant, NERA, has reviewed the documents released by Ofgem as well as supporting analysis prepared by Ofgem's consultants, CEPA.

The full NERA report has been submitted alongside our DD Response (Cost Assessment Annex A). Key highlights of the report have been included below:

For the Draft Determination, Ofgem has put forward its selection of benchmark indices and the resulting RPE allowance. Ofgem's decision wholesale adopts the recommendations put forward by its consultants. NERA considers there are flaws in CEPA's recommendation that may lead the RPE allowance to differ from the input cost growth that would be experienced by an efficient DNO, such that an RPE allowance based on CEPA's recommendation risks undercompensating DNOs for their efficient costs. This outcome would represent a failure of Ofgem's statutory duty to ensure that licence holders can recover efficient costs.

The specific errors in CEPA's analysis are as follows:

- CEPA unjustifiably applies an RPE allowance of zero to cost categories that it deems to be low materiality and to the Other cost category.
- CEPA's process for selecting benchmark indices fails to discriminate effectively between benchmark indices and therefore is excessively reliant on regulatory precedent.
- CEPA combines the specialist and general labour cost categories into a single category that represents 63%of totex for the notional efficient DNO.
- NERA could not reproduce CEPA's RPE forecasts using its method as described, which means that the initial allowance Ofgem provides for RPEs may be inaccurate.

As a result of these errors, Ofgem's Draft Determination may understate efficient costs by millions of pounds across the sector over RIIO-ED2. NERA constructed a series of different forecasts of RPE allowances in which they made a number of different adjustments to correct various combinations of the flaws identified above. The difference between the minimum and the maximum forecast was 8 basis points, with each basis point worth between £2.1m - £2.5m.

Proposed Notional Cost Structure

<u>Labour</u>

For labour, CEPA uses the original cost categories of general labour and specialist labour for index selection. It then takes an unweighted average of the selected indices across both general and specialist labour and uses this average to set the RPE for all labour costs.

This approach is inconsistent with regulatory precedent for electricity distribution. At RIIO-ED1, Ofgem set separate RPE allowances for general and specialist labour. Although Ofgem combined general and specialist labour into a single cost category at RIIO-GD2/T2, it provides no clear justification for doing so.

This approach also means that 63% of DNOs' total costs are being treated as a single, homogenous cost category that can be expected to face common external price pressures. It is implausible that all of these costs grow at the same rate. By failing to separately account for the different labour cost categories, Ofgem increases the risk that it may fail in its statutory duty to allow DNOs to fully recover their efficient costs.

CEPA explains its choice to combine the labour cost categories by pointing out that there is "significant variation across the industry with respect to the split between general and specialist labour costs", citing the difference between ENWL's allocation and WPD's allocation as an example. CEPA suggests that this variation may be driven by DNOs not allocating costs across labour cost categories in a consistent way.

CEPA exaggerates the degree of variation across industry. While it is true that ENWL and WPD have quite different allocations between general and specialist labour, these two DNO groups are the two extremes. NPg, UKPN, SSEN Distribution, and SPEN all have broadly consistent allocations with 40-45% of total labour costs allocated to general labour. The notional cost structure allocates 39% of total labour costs to general labour.

<u>Material</u>
For labour, CEPA does not use the original cost categories of materials (capex) and materials (opex) for index selection. Instead, it uses three groups of materials costs: cables, transformers, and other materials. It then takes an unweighted average of the selected indices across all three groups and uses this average to set the RPE for all materials costs.

The choice to combine materials (opex) with materials (capex) likely reflects the low materiality of the materials (opex) cost category. Materials (opex) constitutes 2.7% of the notional cost structure calculated by CEPA. It can therefore be effectively subsumed into the "other" group of materials costs that CEPA considers when conducting index selection.

The approach CEPA adopts for materials (opex), of subsuming it into a large cost category, is a logically consistent approach to dealing with low materiality cost categories. It does not have the logical flaw of CEPA's proposed approach of setting a zero RPE for low materiality cost categories that one could in principle divide totex into sufficiently few cost categories that there would be a zero RPE for totex. It maintains a reasonable balance between Ofgem's statutory duty to allow DNOs to recover efficient cost growth for materials (opex) that is above growth in CPIH and the practical need to avoid an unduly complex RPE mechanism.

NERA recommend that CEPA adopt the approach it has taken for materials (opex) as a model for how to deal with other low materiality cost categories, such as P&E and Transport.

Assessment of Materiality

CEPA's proposed approach to assessing materiality is based on arbitrarily selected rules and thresholds that are not reflective of Ofgem's stated rationale for introducing a materiality threshold. Ofgem's rationale for introducing a materiality threshold is to set "an RPE indexation mechanism that balances accuracy in reflecting DNO cost pressures with simplicity of application". This suggests that any materiality assessment should explicitly consider whether the benefit of including a cost category (in terms of accurate reflection of DNO cost pressures) exceeds the cost (in terms of resource required to account for any additional complexity).

In setting out its approach to materiality, CEPA fails to consider the balance between accuracy and simplicity, assessing only simplicity. CEPA suggests that "applying RPE indexation to each cost category…would result in a more complex indexation mechanism that would substantially increase the resource required when compared to the indexation approaches Ofgem adopted for RIIO-GD2 and T2".

Our analysis shows that the benefit of setting RPEs for the low materiality cost categories (P&E and transport) exceeds the costs.

The benefit to setting an RPE for these cost categories is that Ofgem accurately reflects the cost pressures DNOs face by allowing them to fully recover efficient costs. If Ofgem does not set an RPE for P&E and transport, DNOs are forecast to under-recover between £6.88 million and £8.30 million of efficient costs over the course of RIIO-ED2.

The cost to setting an RPE is trivial, as is evident from an examination of the RIIO-2 RPE workbook that Ofgem released as part of the 2021 Annual Iteration Process. That workbook contains pre-set formulae linking the raw index data to pre-set weights for each index, based on a notional cost structure that is held constant across the regulatory period. In order to apply the indexation in each year, Ofgem simply has to input the updated raw index data as described on the tab "Sources". The additional cost of setting this workbook up to include a slightly larger number of pre-set weights is trivial, as is the cost of downloading a few extra indices from the ONS, BCIS, and BEAMA once a year.

CEPA's approach to assessing materiality is also inconsistent with regulatory precedent. At RIIO-ED1, Ofgem did apply an RPE to the P&E cost category and used two indices to set the RPE. P&E was 6 per cent of totex in Ofgem's notional cost structure. Ofgem also set an RPE for cost categories with a smaller share of totex: materials (opex) were 4 per cent of totex in Ofgem's notional cost structure, and Ofgem set an RPE based on a single index for that cost category.

Choice of Indices

Overall, NERA found that the impact of varying our assumptions on each of these factors is relatively small. Looking at the forecast annual totex RPE, NERA found that the lowest forecast totex RPE allowance is 0.91%per year, while the highest forecast totex RPE allowance is 0.99%per year – i.e. a range of 8 basis points. It is also not the case that any one combination consistently outperforms the others, looking at the historical data.

SSEN Distribution Response to RIIO ED2 - Draft Determination – Core Methodology

Question ID	Core-Q110.
Question	Do you agree with our proposed approach to setting the ongoing efficiency challenge and the level of challenge applied?
Associated Evidence	
Title	**Link to Evidence**
Cost Assessment Annex B	n/a
Cost Assessment Annex C	n/a
Cost Assessment Annex D	n/a
Response	

We fundamentally disagree with the proposed Ongoing Efficiency (OE) challenge as this is not rooted in evidence and based on a number of material errors.

As part of the ENA, two third-party consultants, NERA and Frontier, were commissioned to review the documents released by Ofgem as well as supporting analysis prepared by Ofgem's consultants, CEPA. In addition, we also independently commissioned Oxera to undertake a detailed assessment of the approach and application that Ofgem and their consultants, CEPA, have used to set the OE challenge.

All three reports have been submitted alongside our DD Response **(Frontier – Cost Assessment Annex B; NERA – Cost Assessment Annex C; Oxera – Cost Assessment Annex D).** All three consultants have individually reviewed the challenge; however, they reached very similar conclusions. We include the key summarised points below.

Ofgem has proposed an ongoing efficiency (OE) challenge of 1.2% per annum. The proposal was informed by a consultancy report by CEPA, commissioned to provide quantitative evidence on the potential savings due to technological progress. CEPA's quantitative evidence on OE ranges from 0.2% to 1.2%, with its estimates clearly centring around 0.6%. Only one of CEPA's estimates—value-added total factor productivity (VA TFP) for the extended comparator set over the full period—produces an OE challenge of 1.2% per annum.

The three independent reports provide clear analytical evidence to show that CEPA's 1.2% estimate of OE is based on errors; and Ofgem's selection of this level of OE challenge for the RIIO-ED2 Draft Determinations is similarly the result of clear errors.

Errors in CEPA's 1.2% estimate of OE highlighted below:

- Value-added total factor productivity (VA TFP) must be estimated over a full business cycle, as also recognised by the CMA. On that basis the 1.2% estimate is invalid. All estimates relying on complete business cycles yield considerably lower results (on average 0.5%). Estimates are not very sensitive to the exact chosen start or end point of the business cycle and results are in a relatively narrow range of 0.1 percentage points. In addition, VA TFP is not applicable to totex.

- In applying an expanded comparator set, CEPA argues that the digital evolution might allow the DNOs to realise higher rates of productivity growth "somewhat closer" to that achieved in more digitally enabled industries. However, its expanded comparator set already considered the digital transformation in the electricity distribution network sector. In addition, CEPA's analysis fails to recognise that (i) spend on IT is in many cases driven by obsolescence and/ or new regulatory requirements; and (ii) where benefit have been accrued as a result of past spend, these have already embedded in our business plan. Therefore, any ongoing efficiency challenge for electricity distribution should not be more stretching beyond the one supported by empirical evidence, which has not been provided by CEPA. Results from a narrow comparator set or the market economy are more appropriate.

- Ofgem argues that past innovation funding provided in previous price controls could lead to further efficiencies beyond those in competitive sectors in RIIO-ED2. On this basis, for GD2, the CMA rejected an uplift from 1% to 1.2%, as they deemed Ofgem had erred when they (i) assumed the innovation funding received by the companies was entirely incremental to the comparator sectors in EU KLEMS; (ii) double-counted innovation cost already embedded in the business plans; and (iii) failed to consider potential distortive effects on companies' incentives to innovate. Ofgem is in danger of repeating previous errors by using past innovation funding as a qualitative argument, without addressing any of the CMA's concerns, to stretch the OE challenge beyond 1% p.a.
- Gross Output (GO) TFP is considerably lower than VA TFP, as the latter provides an estimate for productivity change for a subset of inputs. It is wrong to apply the higher VA TFP to totex without adjusting these figures beforehand. Alternatively, VA TFP should be applied only to the relevant cost base.
    - The use of VA TFP is not a matter of analytical discretion: VA and GO use the same data on Gross Output, Capital (K), Labour (L) and Intermediate Inputs (X) and therefore concerns about measurement error of any of the components apply to both. The ratio between VA and GO measures is not a matter of sampling or volatility over time but is systematic and a function of the relative share of intermediate inputs, capital, and labour in production. VA measures are consistently higher because, in effect, they are expressed in different units
- CEPA and Ofgem downplay the impact of actual productivity trends arguing that regulation provides protection. The operational reality is different. For example, DNOs' workforce was confronted with COVID-19 like in any other industry. Additionally, while focused on keeping the networks running in the current energy crisis and delivering net zero, it will be particularly difficult to embed incremental OE improvements.

Our overall assessment, therefore, is that **Ofgem's ongoing efficiency target is materially wrong. It is not supported by the available evidence, and it is significantly above a valid range**. Using EU KLEMS data with range of 0.1-0.6% based on sensitivity analysis and other sources of evidence consistent with evidence provided by CEPA, our proposed OE challenge of 0.7% p.a. (assumed to start in 2021/22) is already challenging. With the evidence presented, Ofgem cannot legitimately stretch a DNO OE target beyond 0.7-1% per annum. Any additional uplift beyond a 1% target is the result of Ofgem's errors.

Use of Compound Annual Growth Rate (CAGR) as comparator

CEPA argues that company proposals for OE range between 0.5% and 1.0%, with no single DNO proposing a challenge above 1%. They also argue that, due to an earlier starting point, UKPN's OE efficiency assumption of 1.0% per annum and SSE's assumption of 0.7% per annum translate into an efficiency assumption of 1.4% for the former and 0.97% for the latter, calculated on a like-for-like

CAGR basis for five years. This statement is a clear error and misinterpretation of the UKPN and SSEN submissions.

These DNOs applied the OE assumption on the base year 2020/21 and rolled that base cost forward, meaning that some of OE is assumed to be delivered in RIIO-ED1 in order to derive the efficient cost base for RIIO-ED2, while other DNOs applied the OE assumption from on the base year 2022/23.

Both UKPN's and our assumption of efficiencies being delivered in RIIO-ED1 reflects Ofgem's position and their workings, and data tables. It is therefore inappropriate and inaccurate to compare our CAGR (0.97%; and UKPN 1.4%) with Ofgem's proposed 1.2% per annum, with the like for like comparative being to Ofgem's CAGR, which would be well over 1.7%.

Question ID	Core-Q111.
Question	Do you agree with our proposed disaggregation methodology?
Associated Evidence	
Title	**Link to Evidence**
Annex 5 – Material Issues	n/a
Response	

We disagree with the disaggregation methodology proposed by Ofgem.

We agree with Ofgem on the importance of calculating a suitable breakdown of costs at activity level so they can be accurately input into formalised commitments, such as Volume Drivers, PCDs and UIOLI mechanisms. If the incorrect costs are allocated to these areas, then issues can arise in the future with the balance between ex-ante and variant funding.

Furthermore, the presentational aspect of the breakdown of costs at activity level is paramount to ensure transparent and fair critique of Ofgem's modelling approach. For example, within the Core Methodology document for SSEN activities, most modelled costs over submitted costs are presented with a similar % change, a product of the disaggregation methodology utilised by Ofgem. But in some cases, such as IT related expenditure, the reduction in funding is understated, potentially suggesting the modelling approaches utilised did not have such a significant impact. Conversely, other areas such as ONIs are presented with a reduction in funding but the specific disaggregated model and totex assessment suggest increased funding per the RIIO-ED2 cost assessment methodology.

The methodology chosen by Ofgem to combine results has caused a lack of transparency in the presentation of the results and impacted the ability of stakeholders to suitably challenge and critique the cost assessment process.

The accurate way to present the results at activity level is to follow the modelling technique used for assessment:

- The output of the disaggregated modelling performance is applied to 50% of the total allowance.
- The output of the totex modelling overarching efficiency score is applied to the remaining 50% of the total allowance.
- This will calculate the true modelled performance considering both the disaggregated assessment and the totex assessment process. It is then possible to calculate Ongoing Efficiency and other assessments to these modelled figures.

We have utilised this approach to accurately split the assessed totex into the truly modelled activity levels, and all responses in this document will be in reference to this modelled performance as opposed to the Core Methodology figures unless otherwise stated. We have shown our methodology in more detail with a table of updated modelled figures within Annex 5.

We note and welcome Ofgem's and the industry's concerns about this matter and offer support to develop a transparent and fair approach to the disaggregation of the allowances.