Review of the cost assessment in Ofgem's RIIO-ED2 Draft Determinations

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Executive summary

On 29 June 2022 Ofgem published its Draft Determinations (DDs) for the RIIO-ED2 (ED2) price controls for the GB electricity distribution sector.[1] In this report, we review the cost assessment that Ofgem conducted to arrive at what it deems to be efficient costs.

We find that there are a number of clear errors and areas for improvement in the approach proposed by Ofgem, which should be amended at final determination (FD) in order to provide an appropriate estimate of SSEN's efficient cost base. We summarise the core errors and issues below.

Pre-modelling adjustments

- **Sparsity and islands**: Ofgem rejects sparsity and most of SSEN's islands claims as a regional factor. However, top-down econometric modelling shows that a sparsity variable has a positive and significant impact on distribution network operators' (DNOs) costs and demonstrates higher costs for SSEH. The estimated incremental efficient cost impact relative to other DNOs from this top-down modelling is consistent with the bottom-up quantification provided by SSEN in its business plan submission. SSEN has also provided further bottom-up evidence to support its claim.[2] Ofgem should allow SSEN's regional factor claim in full at the FD.

- **Regional wages**: Ofgem recognises higher wages in London and the South East compared to other regions, but not in Scotland. Its reasoning for not applying a higher wage adjustment in Scotland is wrong—there is minimal labour mobility in Great Britain, which has reduced further in recent years with the tightening of the labour market. As a result, wage differentials between Scotland and other regions—that are clear based on Ofgem's own numbers—are persistent and result in significant additional costs for Scottish networks. To correct this and take into account the evidence on higher wages in Scotland, a regional wage adjustment for DNOs operating in Scotland should be made at FD.

Disaggregated models

- **Cost adjustment reversal for high-value projects (HVP)**: in its DDs Ofgem has not undertaken this reversal in the disaggregated modelling—this is incorrect and inconsistent with Ofgem's TOTEX approach. Ofgem should correct the cost adjustment reversal for HVP at the FD.

- **Normalised adjusted costs**: the cost adjustments are inconsistently applied to the normalised ('aggregated') adjusted costs from the normalisation file and not to the normalised ('disaggregated') adjusted costs they were computed on within the individual disaggregated files. This should be corrected.

- **Closely associated indirects (CAIs)/business support costs (BSCs) regression models**: Ofgem uses modern equivalent asset value (MEAV) as a cost driver for these areas. However, the calculation of MEAV is inappropriate for these two areas—OH line and UG cables have similar resource implications, but UG cables receive a weighting that is eight times higher in Ofgem's construction of MEAV. This is inconsistent and incorrect

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[1] Ofgem (2022), 'RIIO-ED2 Draft Determinations', 29 June, https://www.ofgem.gov.uk/publications/riio-ed2-draft-determinations (last accessed 2 August 2022).

[2] SSEN (2022), 'SSEN Response to RIIO-ED2 Draft Determinations, Annex 10, North of Scotland', August.

according to operational insight. Ofgem should use a cost driver that appropriately captures the underlying costs in these areas. We suggest a 'smoothed' MEAV where OH line and UG cables are given equal weight. Other suitable cost drivers that reflect operational implications may also be available and should be tested.

- **Tree-cutting regression:** Ofgem relies on a unit cost model based on spans affected, whereas a model using spans cut as the cost driver (as was used in ED1) is more aligned with how trees are cut in practice. In addition, Ofgem's argument for applying a volume adjustment is not appropriate. Ofgem should correct this by using a model without a volume adjustment.

TOTEX models

- **TOTEX 3**: Ofgem's TOTEX model 3 uses a low-carbon technology (LCT) cost driver where electric vehicles (EVs) and heat pumps (HPs) are weighted equally. This is questionable from an operational perspective, especially at the low voltage level where EVs cause more of an issue than HPs. As the results are sensitive to the weighting used, these weightings should be investigated further.

Post-modelling adjustments

- Demand-based cost adjustment:

  - SSEN's submitted LCT volumes were incorrect and should be corrected at FD;[3]

  - Ofgem's demand-driver adjustment applies the elasticity of cost to LCT from TOTEX model 3 to all TOTEX models. This overstates the impact of LCT on TOTEX models 1 and 2, leading to very high demand-driven adjustments, which should be corrected. An alternative approach would be to extend TOTEX models 1 and 2 to include LCT and/or request cost information from DNOs under different LCT scenarios and benchmark these.

Overall approach to setting efficiency

- **Catch-up benchmark choice**: Ofgem sets the benchmark at the 85th percentile (with a glidepath from the upper quartile). This is not consistent with the level of model uncertainty and lack of robustness. The models used in ED1 had a higher R^2 than the current models and Ofgem used a 75th percentile benchmark. Ofgem's choice of benchmark therefore risks overstating DNOs' level of inefficiency, resulting in material underfunding. Instead, Ofgem should use a 75th percentile benchmark.

- The **disaggregated modelling 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). A similar approach to that used in ED1 should be used instead—namely, aggregating the results from both the TOTEX modelling and the disaggregated modelling and then applying a 75th percentile benchmark.

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[3] Details can be found in SSEN's submission.

- Ofgem weighs all three TOTEX models equally. A different **weighting between TOTEX models** would account for modelling differences more accurately.

Ongoing efficiency

- A proposed **ongoing efficiency (OE) challenge** of 1.2% is not consistent with the vast majority of the evidence and the only productivity figure consistent with this is incorrect, not least because it is not estimated over a business cycle, based on value added total factor productivity (VA TFP) and overestimates the impact of digital spending. Ofgem does not robustly justify its chosen OE challenge nor why it has rejected all of the other evidence. Based on the evidence it has presented, Ofgem cannot legitimately stretch the OE target beyond 0.7–1% p.a. At FD, Ofgem should reduce the OE challenge accordingly.

Overall achievability

- Ofgem's DDs propose significant cuts to SSEN's forecast costs. The OE target of 1.2% is above precedent and not justified by the evidence base, the catch-up target has been pushed to the 85th percentile, the interpolation of costs (between Ofgem's view and the DNOs' view) that was used in ED1 has been removed and significant volumes have either been cut and/or placed in uncertainty mechanisms. At the same time, the quality targets have not been reduced compared to previous price controls—if anything, they have increased.

- These cuts come at a time when increased spend is required to deliver net zero targets. The regulatory focus should be on encouraging and ensuring delivery of net zero and not pushing the efficiency challenge to a level which could discourage investment and/or risk delivery.

1   Introduction

On 29 June 2022 Ofgem published its Draft Determinations (DDs) for the RIIO-ED2 (ED2) price controls for the GB electricity distribution sector.[4] These set out the proposed allowed revenues for all distribution network operators (DNOs) for the five-year period starting 1 April 2023.

SSEN has asked Oxera to review the cost assessment that Ofgem conducted to arrive at its view of efficient costs. We focus on the parts of the assessment that require econometric analysis (i.e. the three TOTEX models and the disaggregated regression models), economic analysis (e.g. some regional factors) and computational errors in the modelling suite. Modelling that mainly requires engineering or operational knowledge (e.g. most of the disaggregated non-regression models) is not covered as part of this report. Real price effects (RPEs) have not been analysed as part of this report.

The cost assessment relies on an extensive modelling suite consisting of 65 Excel spreadsheets, two Stata .do files and a master file that allows data to be passed between files via Excel macros. The modelling suite initially included a number of redactions, and instructions were not provided so it has not been possible to replicate Ofgem's modelling. The complete modelling suite and instructions were only provided on 8 July 2022, leaving insufficient time for a complete review.[5] In particular, several factors have prolonged the review period (described below), leaving less time for a detailed assessment.

- The redactions meant that the modelling suite provided could not replicate Ofgem's results.

- The lack of instructions also meant that it has not been possible to replicate Ofgem's results as it was unclear how the modelling suite should be run.

- The modelling files do not exactly replicate the results in the DDs. For instance, the coefficient of the constant in model 1 is 1.08 in Table 90 of the DDs but 1.11 when running the regression .do file on the original data.

- The overview tables in the DDs do not directly correspond to any tables in the Excel files provided by Ofgem. It therefore took a significant amount of work to reconciliate the results in the DDs (e.g. Table 21).

- Data errors meant that Oxera had to re-run the entire analysis. This was partly due to Ofgem using outdated peak demand data[6] and partly due to a submission error by SSEN. There may be similar data errors for other DNOs. It would have been helpful for Ofgem to share the models and data used in advance so DNOs could have spotted these issues.

Given this context, the time to review Ofgem's modelling suite has been limited, and given the highly complex nature of the models and departure from ED1 in a number of areas, it is critical that Ofgem continues to engage with the DNOs and other stakeholders in the run-up to the FD to ensure that a robust approach to cost modelling is undertaken. Nevertheless, we have reviewed several areas of Ofgem's ED2 cost assessment and conclude that there are a series of errors and areas for improvement. These have resulted in an under-estimation of SSEN's efficiency. Our assessment is summarised in the

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[4] Ofgem (2022), 'RIIO-ED2 Draft Determinations', 29 June, https://www.ofgem.gov.uk/publications/riio-ed2-draft-determinations (last accessed 2 August 2022).
[5] We note that SSEN requested an extension to enable it to properly consider and respond to Ofgem's proposals, which will have a material impact on SSEN but an extension was refused.
[6] Despite the updated data having been provided to Ofgem as part of SQ SSEN084 in February 2022.

remainder of this report, ordered according to the flow of the modelling undertaken by Ofgem.

- Section 2 discusses Ofgem's pre-modelling adjustments, regional and company-specific factors.

- Section 3 covers Ofgem's benchmarking models, including disaggregated modelling and TOTEX models.

- Section 4 discusses Ofgem's post-modelling adjustment, the demand-driven adjustment.

- Section 5 addresses the overall proposed approach to setting the cost efficiency benchmark.

- Section 6 sets out why the proposed ongoing efficiency (OE) figure is incorrect.

- Section 7 looks at the overall package and its achievability.

Our analysis has been run on the data provided by Ofgem in its modelling suite, and hence does not take into account the data discrepancies on peak demand and low-carbon technology (LCT) volumes, unless otherwise stated. However, while the monetary impact differs when correcting for data discrepancies, it does not change the conclusions of our analysis.

The table below shows the allowance as calculated by Ofgem in the DDs,[7] as well as differences to the DD allowance if the proposed changes are to be implemented. The 'Combined' results column presents the impact in the case that all of the proposed changes, including using the updated peak demand and LCT data, are implemented simultaneously. The 'Total' column simply presents the sum of the calculated changes in allowance.

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[7] The allowance refers to efficient costs + bespoke outputs and technical assessments + uncertainty mechanism costs + pass-through items + BPI reward/penalty, including OE and RPEs.

Table 1.1 Impact of proposed adjutsments in Ofgem's modelling (£m)

	Ofgem DDs	Corrected data	HVP	OE	CAI/BSC cost driver	Upper quartile benchmark	Re-weighting TOTEX models	Catch-up efficiency challenge applied to the disaggregated model[1]	Sparsity[2]	Regional wages	Total	Combined[3]
ENWL	1,714	0.6	-	17.4	-7.2	13.0	-2.1	53.5	1.1	-12.1	64.2	73.0
NPGN	1,181	0.9	-	12.2	-2.1	8.5	-5.6	36.1	3.8	-10.7	43.1	48.5
NPGY	1,591	1.4	-	16.5	-5.9	11.5	-4.2	48.8	1.7	-11.1	58.7	66.1
WMID	1,659	1.4	-	16.8	1.5	11.5	2.6	50.1	1.0	-11.1	73.8	83.8
EMID	1,773	1.8	-	17.9	-2.2	12.7	4.7	54.3	0.0	-10.6	78.6	89.6
SWALES	996	1.0	-	10.1	9.0	7.0	7.7	30.2	4.3	-10.2	59.1	65.2
SWEST	1,404	0.8	-	14.2	14.6	9.5	9.7	41.8	2.5	-12.6	80.5	89.2
LPN	1,382	0.4	-	14.0	-25.5	11.0	-5.8	42.4	2.8	-8.8	30.5	38.9
SPN	1,457	0.7	-	14.8	-6.3	11.2	-4.4	46.0	2.3	-8.7	55.6	63.4
EPN	2,233	0.8	-	22.6	3.7	16.8	4.4	69.5	-3.5	-10.8	103.5	115.1
SPD	1,516	0.9	-	15.4	-1.6	10.9	-2.9	46.5	2.2	21.4	92.8	103.3
SPMW	1,543	1.4	-	15.6	4.1	10.4	0.0	45.9	3.5	-11.9	69.0	79.3
SSEH	**1,134**	**16.4**	**15.7**	**11.4**	**17.2**	**8.3**	**2.7**	**35.6**	**15.0**	**11.9**	**134.2**	132.0
SSES	**2,295**	**28.4**	**-**	**23.4**	**-0.7**	**16.0**	**3.9**	**69.3**	**3.2**	**-6.4**	**137.1**	150.2

Note: Ofgem's DD allowance refers to efficient costs + bespoke outputs and technical assessments + uncertainty mechanism costs + pass-through items + BPI reward/ penalty, including OE and RPEs. The impact of the proposed changes in the tree-cutting approach is not included in this table as the impact has only been derived for SSEN. However, as mentioned in section 3.1.4, those changes would lead to a further allowance increase of £7.5m and £9.4m, respectively, for SSEH and SSES. [1] Derived by keeping a glide path from the 75th to the 85th percentile. [2] The sparsity impact has been estimated for the TOTEX models only. Further pre-modelling adjustment would be needed for a number of the disaggregated models, which would increase the impact of this adjustment. [3] Combining a UQ benchmark with the application of a catch-up efficiency challenge to the disaggregated model implies a higher impact than summing both effects individually which is why the combined impact appears higher than the sum of the impact of each adjustment taken individually.

Source: Oxera analysis based on Ofgem's Allowance_File_ED.xlsx, tab 'Out_Allow', AO318-AO331.

2   Pre-modelling adjustments: regional factors and cost adjustments

To ensure that the cost benchmarking is carried out on a comparable basis and that the estimated efficiency is valid, Ofgem normalises costs prior to the modelling. As such, the modelled cost definition is a critical starting point for Ofgem's cost assessment. If costs are not consistent, these inconsistencies become conflated with inefficiency, leading to erroneous results.

We examine two pre-model adjustments in this section—sparsity/islands and regional wages.

2.1   Sparsity and islands

In its DDs, Ofgem rejects sparsity as a regional factor for SSEH[8] and only partially allows for company-specific cost adjustment due to islands.[9]

Ofgem accepts that SSEH is affected by sparsity and islands. Indeed, in its ED1 Business Plan expenditure assessment, Ofgem acknowledged that SSEN had 'provided evidence of additional costs associated with SSEH working in the Highlands and Islands of Scotland'.[10] On that basis, SSEN received allowances for sparsity in ED1.

However, for ED2, Ofgem has proposed not to accept fully SSEN's claim on the basis that:[11]

- Ofgem expects common performance between SSES and SSEH;

- Ofgem does not consider sparsity to be a unique issue.

We examine each of these points in turn.

2.1.1   Common ownership does not imply common performance

In relation to sparsity, Ofgem argues that, 'without controlling for sparsity […] we would expect any impact on SSEH's cost efficiency due to sparsity to lead to a material difference in benchmarking efficiency performance between SSEN's two networks, yet this is not the case even after adjusting for company-specific factors'.[12] However, **comparing the performance of networks' under common ownership is not informative of the need or otherwise for making a regional adjustment**. Networks under common ownership do not necessarily have to have the same relative efficiency. While they may be under common ownership, and therefore might have similar company-wide policies, local management and local factors that are not controlled for in the modelling, are highly likely to result in different estimated relative efficiency.

Indeed, **the evidence shows that networks from the same group do not necessarily have similar efficiency scores, even after accounting for regional and company-specific factors**. For instance:

- in ED2, Ofgem is proposing quite large differences in efficiency between some networks from the same group. The difference in submitted vs

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[8] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, para. 7.44.
[9] Ibid., Table 23.
[10] Ofgem (2013), 'RIIO-ED1 business plan expenditure assessment - methodology and results', 6 December, para. 4.9.
[11] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, para. 7.44.
[12] Ibid., para.7.44.

proposed TOTEX ranges from -16.8% to -23.8% for WPD's networks and from -8.5% to -13.3% for UKPN's networks;[13]

- in GD2, the cuts that Ofgem applied to Cadent's networks were widely dispersed between -5% (EoE) and -14% (Lon). Similarly, SGN's networks had very different cuts applied of -8% (Sc) and -13% (So).[14]

In GD2, Ofgem accepted sparsity as a regional factor and applied an adjustment for it (including for SGN). Given Ofgem's arguments for rejecting sparsity in the ED2 DDs, we would expect the two SGN networks, which are in similar areas to SSEN, to have similar efficiencies. The fact that this is not the case (they differ considerably, by five percentage points) provides clear evidence that other factors are determining network-specific efficiency than the group. **We therefore find that there is no evidence to support this basis of Ofgem's argument for rejecting SSEH's sparsity claim, and as such it is clearly invalid**.

2.1.2 Estimating the efficient cost impact of sparsity across DNOs

Ofgem also argues that it does 'not think sparsity is unique to SSEH and instead may impact other DNOs to some extent'.[15] To examine this issue, following on from Oxera's report on company-specific and regional factors for RIIO-ED2, in which we said that we would examine this when the data became available, we model the impact of sparsity on all DNOs using the data available from the DDs.[16]

In relation to islands, Ofgem accepted SSEH's claim for remote island generation costs, as well as some of the costs associated with submarine cables. These are excluded prior to the modelling. However, in the DDs Ofgem rejects other costs that SSEH incurs as a result of serving many islands, including relocation of staff prior to severe weather events, helicopters, islands flights, accommodation and ferries. Ofgem claims that SSEN did not sufficiently explain or justify the need for, or materiality of, these costs.[17] In addition, Ofgem notes that serving island communities is not entirely unique to SSEH and the incremental impact compared to other DNOs has not been shown.[18] While it is true that some other DNOs also serve islands, as set out previously, Scotland has seven times more islands than England as a whole,[19] which puts SSEH's network in a unique position that none of the cost drivers in Ofgem's DDs modelling suite capture.

In the remainder of this sub-section, **we investigate the sparsity and island claims from a top-down perspective, thereby taking into account the impact *relative* to other DNOs and providing an *efficient* cost impact**. In other words, we examine the impact of sparsity on SSEN and simultaneously the extent of the impact of sparsity on other DNOs, resulting in an estimated incremental efficient cost impact of sparsity on SSEN over and above that of other DNOs and what might be accounted for in Ofgem's model (perhaps through correlation with variables included in the model). This is achieved by including a sparsity variable in the TOTEX regression models.[20] Note, that we do not propose that Ofgem includes such a variable. Instead, we analyse the

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[13] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, Table 21.
[14] Ofgem (2021), 'RIIO-2 Final Determinations – GD Sector Annex (REVISED)', 3 February, Table 8.
[15] Ibid., para. 7.44.
[16] Oxera (2021), 'Company-specific and regional factors for RIIO-ED2', 29 November, p. 25.
[17] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, para. 7.64.
[18] Ibid.
[19] Oxera (2021), 'Company-specific and regional factors for RIIO-ED2', 29 November, Figure 3.1.
[20] This is the same as the RIIO-GD sparsity measure shown in Figure 3.6 of the Oxera company-specific and regional factors paper.

difference in efficient costs with and without the sparsity variable to assess the evidence for sparsity based on the data. This is done in four steps.

1. First, we reverse the adjustment for remote island generation OPEX that Ofgem has applied. This is because the presence of islands is highly correlated with sparsity—with SSEH serving by far the most islands and the sparsest region—so we would expect a sparsity variable to directly pick up this factor.

2. Next, we include a sparsity variable similar to the sparsity index used in GD1 and GD2 in the TOTEX regression models.[21]

3. We then examine model performance, as well as sign and significance of the sparsity variable.

4. Finally, we compare the implicit sparsity value obtained in the model by comparing efficient costs with and without the sparsity variable, and compare this to the regional and company-specific claims made by SSEH.

The regression results are summarised in the table below. While this analysis uses the corrected cost driver data for SSEN, our results are not materially affected by this data adjustment. Our conclusion, that sparsity has a material impact similar to SSEN's bottom-up quantification, remains robust to the data set used.

Table 2.1   Sparsity regression results

	TOTEX model 1	TOTEX model 2	TOTEX model 3
ln_bu_CSV	0.809***		
	(0)		
ln_td_CSV		0.748***	0.718***
		(2.25e-10)	(2.31e-08)
ln_capacity_released_PC		0.0628**	
		(0.0174)	
ln_CGV			0.0907***
			(1.47e-06)
t	0.00218	-0.000960	
	(0.744)	(0.886)	
t_forecast	0.0255**	0.0307***	
	(0.0142)	(0.00537)	
Sparsity	0.103	0.307*	0.435**
	(0.357)	(0.0664)	(0.0120)
Constant	0.917***	-6.107***	-6.165***
	(0.000631)	(5.87e-07)	(2.71e-05)
Adjusted R-squared	0.867	0.861	0.832
Difference in adjusted R-squared compared to model without sparsity	+0.001	+0.017	+0.037

Note: Robust p-values in parentheses; *** $p<0.01$, ** $p<0.05$, * $p<0.1$. We note that the time trend in model 2 becomes negative but it is very close to zero (which is the result reported in Ofgem's DDs) and insignificant.

Source: Oxera analysis based on Ofgem data.

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[21] This is the same as the GD sparsity measure shown in Figure 3.6 of the Oxera company-specific and regional factors paper. It is based on Ofgem's RIIO-GD1 sparsity variable but applied to the DNO regions. Other sparsity variables were tested but did not work so well in the models.

The sparsity variable is positive in all models, in line with operational insight. While it is insignificant in the first model, it is significant at the 10% and 5% levels, respectively, in models 2 and 3. The model fit (adjusted R^2) improves across all models. Overall, this suggests that the variable works well in the TOTEX regressions, apart perhaps from model 1.

In the following analysis, to establish a lower bound conservative estimate, we have set the implied sparsity value from model 1 to zero when calculating the overall impact of sparsity (using the estimated coefficient from model 1 would slightly increase the cost impact of sparsity in the calculations below). The modelling confirms the operational insights of how these factors affect SSEH's costs, as set out in the regional and company-specific factors submission.[22] We apply Ofgem's proposed efficiency challenge to modelled costs to demonstrate that SSEH's sparsity/island costs are material and efficient.

The impact on efficient costs is shown in the table below. The results show that including a measure for sparsity, a variable highly correlated with the presence of islands, results in £93m additional predicted efficient costs for SSEH over and above the £29m adjustment for remote island generation OPEX that Ofgem has applied.

Table 2.2   Impact of sparsity on efficient costs for SSEH (£m)

	Model 1*	Model 2	Model 3	Average taking sparsity in model 1 to be 0
Change in efficient cost due to sparsity variable	-	108	170	93

Note: * The impact has been set to zero because the coefficient is not significant. Efficient costs were derived by carrying out the following calculations for the models with and without a cost driver capturing the impact of sparsity: calculating modelled (predicted) costs, calculating efficiency scores for each of the three TOTEX models, calculating the benchmark efficiency score and finally calculating efficient costs as benchmark efficiency score times modelled (predicted) costs. We show the difference in efficient costs between the scenario in which a sparsity variable is added to the model and the scenario in which no sparsity variable is added.

Source: Oxera analysis.

Table 2.3 below shows how the estimated sparsity/islands figure compares to the regional and company-specific factor claims that SSEN submitted in its business plan.

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[22] Oxera (2021), 'Company-specific and regional factors for RIIO-ED2', 29 November.

Table 2.3   Impact of sparsity based on modelling compared to regional and company-specific claims (£m)

	p.a.	RIIO-2
Efficient sparsity cost based on modelling	18.5	**92.6**
Sparsity and island factors not considered in Ofgem's modelling		
Sparsity (excl. North of Scotland resilience)*	10.5	52.6
Island flights, accommodation and ferries	0.4	2.2
Helicopters	0.1	0.5
Deployed staff prior to forecast severe weather	0.3	1.3
Submarine cables team	1.5	7.5
Total	12.8	**64.0**

Note: * Ofgem proposes to treat SSEH's NoSR costs through a reopener in ED2 rather than ex ante funding, and so it has removed historical and forecast costs prior to cost modelling. We therefore exclude NoSR here as well.

Source: Oxera (2021), 'Company-specific and regional factors for RIIO-ED2', 29 November, Table 2 and 3; Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, para. 7.63.

The estimated efficient cost impact resulting from sparsity/islands as predicted by the regression models (£92.6m) is higher than the submitted claims that were not accepted (£64.0m and £85.9m including North of Scotland resilience).[23] **The modelling therefore confirms the regional and company-specific factors that SSEN submitted and quantified in a bottom-up way, and suggests that these values were conservative and efficient** (as the modelling above is undertaken on a relative basis and estimates the impact on SSEH's efficient cost).

We do not suggest that Ofgem necessarily needs to account for sparsity by using a variable directly in the regression models. Instead, the analysis above provides additional evidence of SSEH's original sparsity claim, clearly demonstrating the impact over and above other DNOs. **Ofgem should therefore adjust SSEH's costs prior to the modelling by accounting for these factors.**

2.1.3   Further bottom-up evidence

In addition, we note that SSEN has provided further bottom-up evidence.[24] With regard to Ofgem's point about the increase in costs since ED1 as a reason for rejecting the full amount of the regional factor claim,[25] SSEN notes that:[26]

- ED1 regional factor allowances underestimated the additional costs that SSEN had been exposed to;

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[24] SSEN (2022), 'SSEN Response to RIIO-ED2 Draft Determinations, Annex 10, North of Scotland', August.
[25] For example Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June paras 7.63 and 7.65.
[26] SSEN (2022), 'SSEN Response to RIIO-ED2 Draft Determinations, Annex 10, North of Scotland', August.

- SSEN's estimate for ED2 is broadly aligned with SSEN's average spend over ED1 and lower than the costs that SSEN incurred in the most recent year.

With regard to Ofgem's rejection of SSEN's cost proposal on subsea cables, SSEN states that the costs are due to its proposed proactive approach. SSEN shows that, without a proactive approach, the overall costs are likely to increase due to the risk of reactive interventions instead of proactive ones or if the intervention were postponed to ED3 with less control over the supply chain costs.[27]

2.1.4 Overall impact of sparsity and islands

The impact of an additional £12.8m p.a. pre-modelling adjustment for these factors has been quantified in the TOTEX regression models. Table 2.4 shows the impact on efficiency scores with an additional sparsity adjustment compared to the case without. In both cases, data errors on LCT and peak demand have been corrected.

Table 2.4   Efficiency scores with additional pre-modelling sparsity/islands adjustment

DNO	Without additional sparsity adjustment		With additional sparsity adjustment	
	Efficiency score	Gap to benchmark	Efficiency score	Gap to benchmark
Combined models				
ENWL	1.06	8%	1.06	8%
NPGN	1.02	4%	1.03	4%
NPGY	1.00	2%	1.01	2%
WMID	1.03	5%	1.03	5%
EMID	0.98	0%	0.98	0%
SWALES	1.00	1%	1.01	2%
SWEST	1.18	20%	1.19	21%
LPN	0.88	-11%	0.88	-10%
SPN	0.91	-8%	0.91	-8%
EPN	0.99	0%	0.99	0%
SPD	0.96	-2%	0.97	-2%
SPMW	1.02	3%	1.02	4%
SSEH	**1.04**	**6%**	**1.00**	**1%**
SSES	1.12	13%	1.12	13%
Benchmark	0.99		0.99	

Source: Oxera analysis.

As expected, SSEH's gap to the benchmark decreases when the additional pre-modelling adjustment is introduced. Other companies are sometimes also affected, but to a much lesser extent.

2.2 Regional wages

In its DDs, Ofgem has proposed not to make a pre-modelling adjustment to account for higher labour costs in Scotland. Ofgem argues that:

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[27] SSEN (2022), 'SSEN Response to RIIO-ED2 Draft Determinations, Annex 10, North of Scotland', August.

- London remains a clear outlier in terms of regional labour costs, with the effect extending to the South East;[28]

- there is not sufficient and compelling new evidence to indicate that this has changed compared to ED1 and GD2;[29]

- there is sufficient mobility of labour to mitigate wage differentials throughout GB (apart from London).[30]

2.2.1   Evidence clearly shows that the regional wage effect extends to Scotland and has been persistent

We first provide evidence on wage data across regions in Great Britain, demonstrating that wages in Scotland are persistently higher than in other regions. Ofgem's own approach shows that Scotland has the third highest wage rate in Great Britain, with a wage rate similar to that in the South East especially in recent years. This is followed by wage levels in the East, with wages in the rest of the country clearly below these levels. The regional wage comparison based on Ofgem's analysis is provided below.

Figure 2.1   Regional wage indices in Ofgem's analysis
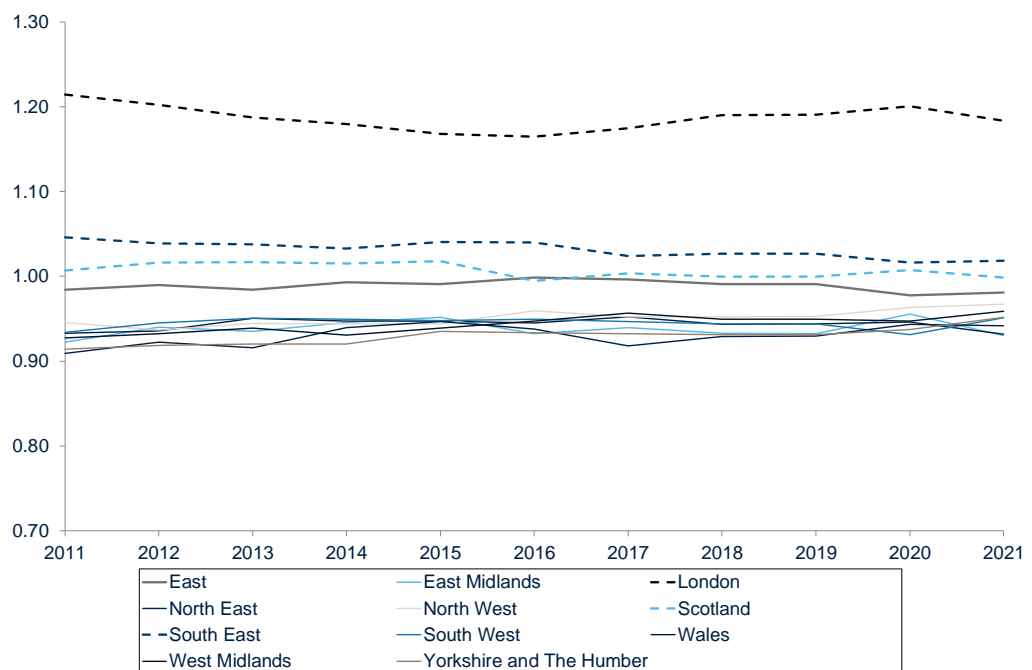
Source: Ofgem (2022), 'ED2_RegionalCostIndices.xlsx'.

The regional wage comparison based on Oxera's (2021) analysis is very similar and provided below.[31] There are slight differences as our analysis relied on ED1 precedent, whereas Ofgem has now made small adjustments to how it calculates regional wages indices.[32] Nevertheless, the conclusions drawn in our regional and company-specific factors report remain valid.[33]

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[28] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, para. 7.38.
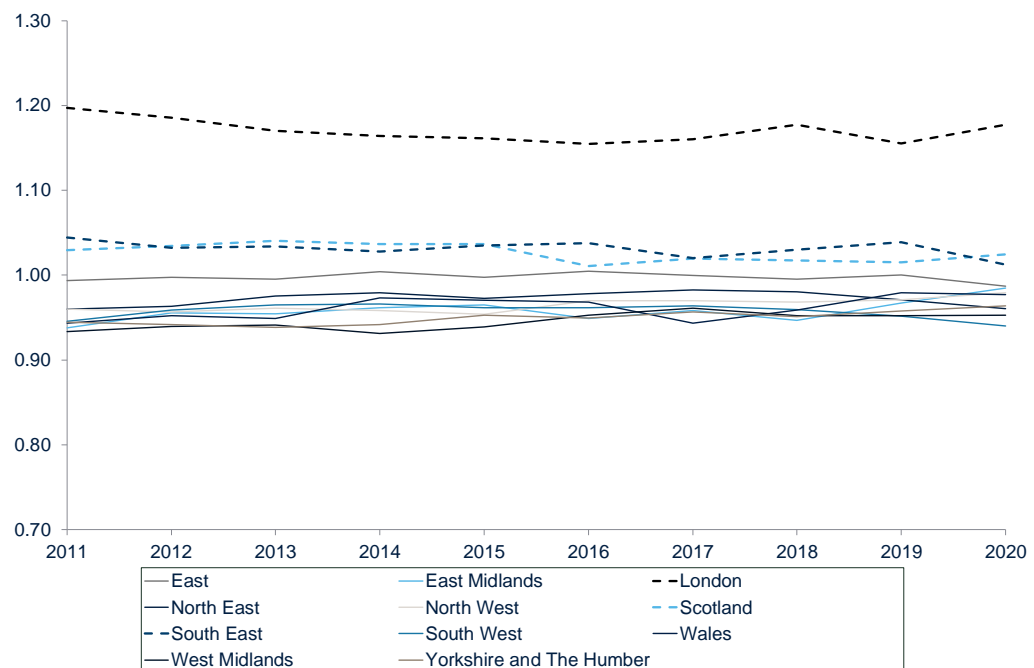[29] Ibid.
[30] Ibid, para. 7.39.
[31] Oxera (2021), 'Company-specific and regional factors for RIIO-ED2', 29 November, Section 3.31.
[32] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, Table 87.
[33] Oxera (2021), 'Company-specific and regional factors for RIIO-ED2', 29 November, Section 3.3.

Figure 2.2   Regional wage indices in Oxera (2021)

Source: Oxera (2021), 'Company-specific and regional factors for RIIO-ED2', 29 November, section 3.31.

The evidence on regional wages shows **labour costs in some regions, including Scotland, to be persistently above the rest of Great Britain**. This fact in itself shows Ofgem's labour mobility argument to be flawed and contrary to the available evidence. If there was sufficient labour mobility then we would expect wages to converge over time, as workers would move from lower-wage to higher-wage areas until the labour supply in formerly higher-wage areas meant that the cost of labour in such areas dropped.

2.2.2   There is a clear lack of regional labour mobility in Great Britain, which has further reduced in recent years

In addition, we have provided new evidence to show that regional labour mobility is actually very limited—as generally agreed among economists.[34] As Professor Ken Mayhew states in his expert report,[35] 'In my expert opinion, **I consider that Ofgem's argument is flawed and there is a significant amount of evidence to demonstrate this**.' Widespread shortages of labour across the regions of the UK are likely to have reduced inter-regional mobility in the foreseeable future. If there are plenty of jobs available locally, people have no incentive to relocate for work. As Professor Mayhew states:[36] '**recent labour market developments are highly likely to have reduced internal migration still further**'.

This further exasperates the issues highlighted in SSEN's Workforce Annex, where skills shortages and competition are increasing costs for skilled workers.[37] For instance, the proportion of the workforce aged 60 years or older

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[34] See for instance McCann, P. (2013), *Modern Urban and Regional Economics*, second edition, Oxford: Oxford University Press.
[35] 'An expert submission for SSEN by Professor Ken Mayhew'.
[36] Ibid.
[37] SSEN Distribution (2021), 'STRATEGY FOR BUILDING A DIVERSE, SKILLED AND RESILIENT WORKFORCE FIT FOR THE FUTURE-RIIO- ED2 Business Plan Annex 16.3'.

has increased by 7% between 2013 and 2021.[38] SSEN's business plan also mentions the issue of an ageing employee base,[39] as well as a general shortage of skills.[40]

Overall, this evidence demonstrates that **there should be a Scotland-specific regional wage adjustment or, alternatively, a wage adjustment for every region**. The former approach would rely on the following wage indices. Table 2.5 shows wages to be 5% higher for SSEH than under Ofgem's DD approach, which groups it with the rest of the country. While this might seem like a small proportion, it makes a material difference to SSEH's costs, which should be reflected in its allowances.

Table 2.5   Alternative regional wage indices

	Original wage index (average over RIIO-2)	Alternative wage index (average over RIIO-2)
ENWL	1.00	1.00
NPGN	1.00	1.00
NPGY	1.00	1.00
WMID	1.00	1.00
EMID	1.00	1.00
SWales	1.00	1.00
SWest	1.00	1.00
LPN	1.24	1.25
SPN	1.10	1.11
EPN	1.06	1.06
SPD	1.00	1.05
SPMW	1.00	1.00
SSEH	1.00	1.05
SSES	1.07	1.08

Source: Oxera based on Ofgem's DD files.

Applying these wage indices would result in higher allowances for the two Scottish networks, SSEH and SPD, of £11.9m and £21.4m respectively. The allowances for other DNOs decrease, with SSES's allowances reducing by £6.4m.[41]

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[38] EUSkills, 'External influences on the skills and workforce of the power sector', p. 1.
[39] SSEN Distribution (2021), 'STRATEGY FOR BUILDING A DIVERSE, SKILLED AND RESILIENT WORKFORCE FIT FOR THE FUTURE-RIIO- ED2 Business Plan Annex 16.3', p. 7.
[40] Ibid., p. 52.
[41] Even though the wage index increases slightly, SSES's allowance decreases as other networks' indices increase by more.

3   Benchmarking models

Ofgem's modelling suite consists of a range of disaggregated models for each individual activity, which mostly rely on unit cost analysis as well as three disaggregated regression models.

3.1   Disaggregated modelling

Having review Ofgem's disaggregated modelling, we find four areas where Ofgem's modelling is incorrect and should be amended to provide an appropriate estimate of SSEN's efficiency.

3.1.1   SSEH's missing high-value projects reverse regional adjustment

In order to be able to compare DNOs' costs effectively, when relevant Ofgem applies pre-modelling regional adjustments to the different cost areas. They are then reintroduced ex post. However, having reviewed Ofgem's DD adjustments, we have identified that **the post-modelling reverse adjustments have not been undertaken on high-value projects (HVP) in the disaggregated model.**

While SSEH's HVP reverse regional adjustment is correctly made after the TOTEX modelling, it is missing in the disaggregated model due to a clear error in how Ofgem has reintroduced those regional adjustments.

In total, SSEH has submitted HVP costs of up to £40m, of which £8m is considered by Ofgem to be bespoke outputs and is then separately assessed. As a result, only £32m flows into the individual Excel model assessing HVP costs and is eligible for a benchmark assessment.[42]

In the individual Excel model assessing HVP costs, the totality of SSEH's remaining HVP costs (£32m) concerns submarine cables, which are then logically considered as company-specific. Consequently, the normalised adjusted costs of SSEH are zero and, by definition, its modelled costs as well. As per the other costs areas, regional adjustments are supposed to be reintroduced in the PostAnalysis_File_SSEH based on the ratio between modelled costs and normalised adjusted costs. However, no adjustment is made due to a formula error.

Indeed, although the regional adjustment is *correctly* pasted in row 1121 of tab 'Cal_Disagg_CapexAdj', the formula in the following row (#1122) computing the ratio and the scope of the regional adjustment reversal is *incorrect*. This formula is currently set to:

$$Regional\ adjustment\ reversal's\ ratio = IFERROR(\frac{Modelled\ costs}{Normalised\ adjusted\ costs}, 0)$$

This formula is not appropriate for cost areas where 100% of companies' submitted costs[43] are seen as regional specificities and are taken out from the comparative assessment. This unfairly penalises concerned companies as the final ratio used to derive the global allowance in the disaggregated model is artificially reduced.[44] This is the case for SSEH for HVP and may also be the case for other DNOs in the event of such a pre-modelling adjustment.

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[42] Those costs are assessed qualitatively and no unit cost analysis is carried out. However, none of the companies have seen their normalised adjusted costs being reduced.

[43] Excluding any bespoke outputs that are assessed separately.

[44] This ratio is simply derived by dividing modelled costs by the modelled component of submitted costs. As SSEH's modelled component of submitted costs comprises HVP costs of £32m but its modelled costs do not

Instead of the formula specified above, the corrected version should be:

$$Regional\ adjustment\ reversal's\ ratio = IFERROR(\frac{Modelled\ costs}{Normalised\ adjusted\ costs}, 1)$$

There is no justification for penalising DNOs for having costs that are specific to their operating area. **Indeed this is inconsistent with the same post-modelling adjustment that Ofgem makes for its TOTEX models in the post analysis file** (row 45 of tab 'Inp_RegAdj' which then flows back into the three different TOTEX models in rows 21-23 of tabs 'Cal_TOTEX1Adj', 'Cal_TOTEX2Adj' and 'Cal_TOTEX3Adj').

Correcting the error in Ofgem's formula would mean an overall disaggregated ratio of 0.8383 instead of the actual one applied in the DDs of 0.8263. **For SSEH, the impact is significant with the final allowance wrongly reduced by £15.68m. The current final allowance is £1,134.02m while it should be £1,149.70m.**[45]

3.1.2 Normalised adjusted costs

While costs are normalised at a whole cost area level in the normalisation files, they are disaggregated further in the individual disaggregated files as costs are normalised per sub-category in order to be able to compare costs more effectively and to run a more tailored unit cost analysis.

This is the correct approach, as running a unit cost analysis at a whole cost area level without distinguishing the potential heterogeneity in costs and efficiency within the different sub-categories would not be appropriate and would undermine the relevance of the models.

However, the further disaggregation of normalised adjusted costs into different sub-categories creates slight differences with the normalised ('aggregated') adjusted costs derived in the normalisation files. For example, SSES's primary reinforcement normalised adjusted costs are set to £108.98m in the normalisation file, whereas they are indicated as being £109.29m in the individual disaggregated file related to primary reinforcement. This is also the case on some other cost areas and concerns both SSES and SSEH, as well as other DNOs. While this divergence is not an issue per se, it becomes one in the non-regression file when all the disaggregated files are combined together since costs adjustments are not applied to the costs they were computed on but to others, which represents a model inconsistency.

The further disaggregation of normalised adjusted costs to differentiate between sub-categories implies slightly higher costs on average for SSEN. The benchmark assessment is based on those slightly higher costs, which means than the cost adjustments are computed based on those costs as well.

In the non-regression file, however, the cost adjustments are inconsistently applied to the normalised ('aggregated') adjusted costs coming from the normalisation file and not to the normalised ('disaggregated') adjusted costs they were computed on within the individual disaggregated files.

If cost adjustments are computed on higher normalised adjusted costs it means that they are, in absolute terms, automatically higher at the end. As

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comprise any HVP costs due to missing reverse regional adjustments, the ratio is mechanically artificially reduced and the final allowance as well.

[45] This number comprises efficient costs + bespoke outputs and technical Assessments + uncertainty mechanism costs + pass-through items + BPI penalty, post OE and RPEs (cell AO330 of tab 'Out_Allow' in the Allowance file).

SSEN is globally found to be inefficient in the disaggregated models, **SSEN is unduly penalised further at the time of applying those cost adjustments because it artificially reduced its modelled costs**. Going back to the primary reinforcement example mentioned above, as SSES's cost reduction of £3.44m has been computed based on costs of up to £109.29m, it is not appropriate to apply a cost reduction of £3.44m to its costs of £108.98m but rather to the £109.29m they were computed on. Consequently, SSES's modelled costs should be 105.85m and not 105.54m.[46]

When the normalised ('aggregated') adjusted costs coming from the normalisation file are higher than the normalised ('disaggregated') adjusted costs, it means that modelled costs of efficient companies are artificially inflated while inefficient companies are penalised further. **As a result, both SSES's and SSEH's final disaggregated ratios have been wrongly reduced given the inconsistency in normalised adjusted costs.**

Correcting this inconsistency would result in an allowance prediction increase of c. £2m–£4m for SSEN.

3.1.3   Closely associated indirects and business support costs

Modern equivalent asset value (MEAV) plays a significant role as a cost driver in this cost assessment. In the majority of cases, we agree in principle with the calculation of MEAV. However, in the case of indirect related expenditure, such as closely associated indirects (CAIs) and business support costs (BSCs), MEAV in its current form is not an appropriate cost driver.[47]

Ofgem proposes to model CAIs and BSCs using regression models with MEAV (and time trends) as the only cost driver. MEAV is a measure of a DNO's assets, weighted by an asset-specific unit cost. However, for back-office functions, this type of weighting is likely to be inappropriate. This is because all types of cables have similar resource implications and therefore should have similar weighting in the cost driver used. However, cables currently have materially different weightings in MEAV, with underground cables receiving a unit cost that is over eight times higher than overhead lines. This is inconsistent with operational insights. In fact, SSEN's own analysis shows that underground cables could lead to costs in this area that are about 1.5 times those for overhead lines,[48] significantly less than the ratio of eight implied by the original MEAV calculation.

For simplicity, we examined the impact of setting equal weights on underground and overhead cables for each category of voltage in MEAV—we refer to this as smoothed MEAV below.[49] We did this by applying an average unit cost to all cable and line assets per voltage level to remove the distortion from the different value of assets on back-office costs.[50]

If MEAV were to be amended this way, in the disaggregated modelling both CAIs (regression component) and core BS modelled costs would improve markedly for SSEH (by £28.4m and £7.6m, respectively) but worsen slightly for

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[46] Before the demand-driven adjustment, reverse regional adjustment and reintroduction of costs eligible to separate assessment.
[47] This might also apply to other costs, such as property and STEPM, which are not covered as part of this report.
[48] Analysis provided by SSEN.
[49] Applying a weighting of 1.5 would have a slightly lower, but still material, impact.
[50] We also applied this adjustment to subsea cables. We calculated the average unit cost for each voltage category by weighting each category's unit cost by its length.

SSES (BS modelled costs decrease by £1.6m and increase for CAIs by £1.4m, respectively), as we can see in Table 3.1.

Table 3.1   Change in cost prediction from equalising the weighting on cables and lines in MEAV on CAI and BSC regressions (£m)

	BS predicted costs	CAI predicted costs	Total
SSEH	7.6	28.4	36.0
SSES	-1.6	1.4	-0.1

Note: Sums may not add up to the total due to rounding differences.

Source: Oxera analysis.

The overall impact on TOTEX allowance is an increase in £17.2m for SSEH and a decrease of £0.7m for SSES. This is likely to be a conservative estimate as we have not applied the MEAV adjustment to the disaggregated component for CAIs or BSCs, nor for the TOTEX models as a cost driver for these back-office categories.

While the operational evidence is clear, in terms of statistical evidence, the adjusted R^2 falls slightly. The results are summarised in Table 3.2.

Table 3.2   Variations in R^2

	R^2	Adjusted R^2
Original BS regression	0.66	0.65
BS regression with smoothed MEAV	0.57	0.56
Original CAI regression	0.75	0.75
CAI regression with smoothed MEAV	0.69	0.69

Source: Oxera analysis.

Overall, it is clear from the operational insight that a change to the cost driver used in these regressions is required. Given the size of the data set, such operational insight should outweigh the minor impact on the statistical results. Other more suitable cost drivers that reflect operational implications may also be available and should be tested.

3.1.4 Tree cutting

At ED1, the assessment of tree-cutting costs was made through two separate analyses: a regression analysis of ENATS 43-8 activity with spans cut and spans inspected as cost drivers, and a unit cost analysis for ETR 132 activity[51] using industry median as benchmark. On ENATS 43-8 activity, Ofgem did not apply any workload adjustment but applied a scaling adjustment. Both activities were then combined to form the total tree cutting predicted costs.

Although Ofgem initially proposed to run the regression from 2010–11 to 2012–13, after having considered DNOs' concerns, it changed the time period to ED1 only.[52]

For ED2, Ofgem has proposed a change in approach compared to ED1. It now proposes a unit cost analysis on ED1 and ED2 data, for both ENATS 43-8 and ETR 132 activities, retaining the median unit cost as the reference benchmark.

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[51] Excluding NPg from the assessment, given its different approach to reporting costs and volumes in this area.
[52] Ofgem (2014), 'RIIO-ED1: Draft determinations for the slow-track electricity distribution companies. Business plan expenditure assessment', July, https://www.ofgem.gov.uk/sites/default/files/docs/2014/07/riio-ed1_draft_determination_expenditure_assessment.pdf, paras. 9.18 and 9.19 (last accessed 2 August 2022).

Ofgem states 'in the preliminary phase of our assessment we considered using regression analysis, but we discarded the option as results were not statistically robust'.[53]

However, when examining a regression on ENATS 43-8 activity using spans cut as a cost driver we found the coefficients to be significant at a 1% level as well as a satisfactory R^2. The regression analysis estimated a spans cut coefficient of 0.76, which is in line with operational insight. Spans cut activities represent the most significant part of ENATS 43-8 costs for the DNOs, accounting for an average of 89% of the total spend within the industry.

The R^2 is comparable to other disaggregated regression models used by Ofgem—it is higher than the R^2 in the BSC model (0.69 versus 0.66) and close to the R^2 in the CAI model (0.75). Moreover, moving from a regression model to a unit cost model does not remove any possible model robustness issues as a unit cost model is simply a restricted version of the regression model.

As such, it is clearly inconsistent for Ofgem to dismiss this model, but to use a regression model to assess BS and CAI costs.

In addition, Ofgem's benchmark analysis for tree cutting relies on spans affected as the denominator. This is not the best measure to assess the efficiency of tree cutting as it is not directly related to the actual activity undertaken by each DNO. Ofgem's approach could favour DNOs that are underdelivering their volumes of spans cut as they would appear more efficient in a unit cost analysis undertaken on spans affected. While acknowledging that spans cut is somewhat endogenous, we note that Ofgem includes endogenous cost drivers in its regression analysis of faults and ONIs, by relying on activity drivers such as faults and ONIs volumes. Moreover, capacity released is a key driver in TOTEX model 2 while being under management control. The latest set of LiDAR surveys is a way for Ofgem to ensure that DNOs are not exaggerating the need and the scope of spans cut over ED2, considerably alleviating the endogeneity issue.

Implementing a regression analysis using spans cut improves the R^2 compared to a model using spans affected, 0.69 versus 0.61. This cost driver could also be used in a unit cost base model, rather than a regression model.

A model based on spans cut is more aligned with operational insight than a model based on spans affected and thus a superior approach.

Relying on a regression analysis for the main driver of ENATS 43-8 costs, spans cut, does not prevent Ofgem from running a separate unit cost analysis on the other minor driver of the costs, spans inspected, if needed. However we note that some DNOs, including SSEH and SSES, have not submitted any volumes for spans inspected for the last three years of ED2, given that LiDAR is now replacing the need for manual inspections to determine the number of affected spans. As such, it is more appropriate to rely on spans cut as the main cost driver.

Regarding the ETR 132 activity, as in ED1, a unit cost analysis appears to be the most suitable way to assess related costs. They can then be combined with ENATS 43-8 predicted costs to form Ofgem's view of tree-cutting predicted costs.

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[53] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', June, para. 7.359.

SSEN also has concerns surrounding the volume adjustment and the way it has been estimated. Ofgem argues that, given that the next set of LiDAR surveys (due to be undertaken in 2025 and 2026) would represent a better estimate than the current LiDAR inspection, the current LiDAR inspection cannot be used as the basis for the ED2 volumes and a downward volume adjustment is needed. This argument is invalid as it would imply that none of the future submitted volumes could be justified, given that the next set of LiDAR surveys will still represent a better estimate than the one available at the time of Ofgem's assessment.

A regression analysis with spans cut as a cost driver would lead to higher ENATS 43-8 predicted costs for SSEN, c. £86m for SSES and c. £54m for SSEH, versus £68m and £39m, respectively, as predicted by Ofgem.[54]

After combining ENATS 43-8 predicted costs with ETR 132 predicted costs and relying on the latest set of LiDAR surveys available,[55] the final tree-cutting predicted costs are: £56.6m and £92.9mfor SSEH and SSES —respectively so £15.2m and £19.1m higher than Ofgem's predicted costs.

Applying a regression on ENATS 43-8 costs without any volume adjustment, as set out above, would result in an allowance increase of £7.5m for SSEH and £9.4m for SSES.

While the above analysis shows that a regression model is feasible, Ofgem could also improve its model by using spans cut in a unit rate model, as set out in SSEN's own submission on tree cutting.

3.2   TOTEX models

Ofgem's proposed TOTEX modelling is generally a positive improvement: the composite scale variable (CSV), especially in TOTEX model 1, is now broader and the variable customer numbers no longer has a counter-intuitive weight (see Oxera (2021))[56]. However, there are certain points in the proposed approach that require further consideration (see below and section 5).

3.2.1   The low-carbon technology driver in TOTEX model 3—heat pumps/electric vehicles

Ofgem has extended its ED1 modelling approach by including a cost driver that captures the effect of LCTs. This is included in TOTEX model 3 as an activity driver (in addition to the CSV cost driver). This driver is particularly important because the coefficients and predicted costs from this model are used in the demand-driven adjustment, which has a very significant impact on modelled costs overall (see section 4).

Ofgem currently calculates the activity driver as the sum of half the logarithm of cumulative number of heat pumps (HPs) and half the logarithm of cumulative size of electric vehicle (EV) chargers in MW. Ofgem has arbitrarily chosen this weighting of 0.5 and 0.5. However, further analysis is required to determine the relative impact of EVs and HPs on the network (and therefore on costs). In particular, the equal weighting is questionable from an operational perspective, especially at the low voltage level where EVs cause more of an issue than HPs.[57]

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[54] The regression analysis does not include any volume adjustments.
[55] Using the LiDAR data does not materially affect the results for SSEH—predicted tree-cutting costs are £55.9m for SSEH and £67.0m for SSES.
[56] Oxera (2021), 'Estimating an appropriate efficiency challenge', 29 November.
[57] Information provided by SSEN.

Instead of a 50/50 weighting, in line with operational insights from SSEN's load team, we suggest weighting EVs and HPs according to their volume for each year to more accurately reflect the relative importance of EVs and HPs in the uptake of LCTs. Doing so leads to the expected increase in weighting for EVs in the activity driver.

As Ofgem's view of the number of EVs is unavailable, we have been unable to calculate the demand-driven adjustment in our proposed adjustment, and so cannot provide comprehensive results for this adjustment. However, re-estimating the baseline regressions, we find that the adjusted R^2 for TOTEX model 3 increases by 0.03.

Table 3.3   TOTEX Model 3 statistics

	Original	**Weighting by volume**
R^2	0.810	0.813
Adjusted R^2	0.806	0.809

Source: Oxera analysis.

We also examine the impact on allowances under a different weighting. For illustrative purposes and because SSEN highlighted a potential greater impact of EVs, we run a model with a weighting of 0.75 and 0.25 on EVs and HPs, respectively. This change results in a very significant change in the cost predictions—for example, an increase in TOTEX allowance of £20.1m and £25.9m for SSEH and SSES, respectively. Given the significant sensitivity of the cost prediction *and* the resultant impact on the demand based cost adjustment (see section 4) from changes in the model, it is inappropriate for Ofgem to base this large demand-driven adjustment on this one model.

4   Post-modelling adjustment: demand-driven adjustments

Ofgem's benchmarking relies on DNOs' business plan forecasts of costs and cost drivers. As Ofgem did not mandate a consistent LCT scenario for DNOs to use, the LCT scenarios used by DNOs in their business plans are inconsistent. As a result, Ofgem is concerned that this may inflate some DNOs' forecast costs if they have assumed higher LCT numbers than what Ofgem deems reasonable. Ofgem therefore applies a demand-driven adjustment to scale down modelled costs depending on how different a DNO's forecast of LCT was compared to Ofgem's view (which is based on National Grid's system transformation scenario). This is done in the following way.

- Ofgem runs the TOTEX model 3 regression, which explicitly uses LCT as a cost driver.

- It then uses the coefficients obtained in the regression and creates predicted costs based on Ofgem's view of LCT. That is, it multiplies the coefficient obtained in the regression by the LCT variable based on National Grid's system transformation scenario.

- Ofgem then compares the predicted costs obtained from the above exercise to the predicted costs obtained by using DNOs' own forecast LCT volumes.

- The percentage difference of the above is then applied across the TOTEX models and load-related cost areas (Connections, NTCC and reinforcement).

This results in very large downward adjustments to SSEN's allowance of £54m (SSEH) and £90m (SSES).[58]

There are two issues with Ofgem's demand-driven adjustment. First, SSEN's submitted LCT volumes were incorrect. Second, Ofgem's approach to estimating the demand-driven adjustment is likely to overestimate the adjustment. We explain these two points in more detail below. Additionally, we note an inconsistency in the starting point when constructing the variables for HPs and EVs, with one starting in 2020 and the other in 2022.

4.1   LCT volumes

SSEN identified that it submitted incorrect LCT volumes, which should be corrected for.[59]

Re-running the analysis with the correct LCT volumes (and the updated Ofgem peak demand data) reduces the demand-driven adjustment for SSEN across the TOTEX models from -£96m to -£45m (SSEH) and from -£161m to -£64m (SSES). As the impact on the disaggregated models is smaller,[60] the overall effect of this change for SSEN is a higher allowance of £16.4m for SSEH and £28.4m for SSES.

4.2   Ofgem's approach to the demand-based cost adjustment

Another issue with Ofgem's approach is that it relies on the elasticity of costs to LCT volumes obtained from TOTEX model 3 and applies this across the other models. However, it is neither clear nor is any evidence provided by Ofgem for

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[58] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, Table 22.
[59] See SSEN's response to CQ 105.
[60] For the disaggregated models, the adjustment is only applied to the load-related cost categories.

why the same elasticity should apply across the three models. For instance, it is possible that TOTEX models 1 and 2 are less sensitive to LCT. That is, a change in LCT volumes would not lead to as large a change in predicted costs under models 1 and 2. If this were the case then applying the elasticity from model 3 would overestimate the impact of LCT on the other models and therefore overestimate the demand-driven adjustment.[61]

As an alternative, Ofgem could directly include an LCT variable in TOTEX models 1 and 2 to estimate the elasticity. Such an approach shows the elasticity in these models to be lower than that in model 3 (with coefficients of 0.07 and 0.08, respectively, compared to 0.09 in model 3). While significant in TOTEX model 1, the coefficient in model 2 is not significant.

This alternative approach suggests that Ofgem's current approach overstates the impact of LCT on costs. The demand-driven adjustment is therefore too high.

Furthermore, there is uncertainty on the demand-driven adjustment and it is very sensitive to various changes. As noted above in section 4.1, SSEN submitted incorrect LCT data, which significantly changed the demand driver adjustment. Also, when implementing the 75/25 weighting on EVs and HPs, as discussed in section 3.2.1, the demand-based cost adjustment changes significantly. Given the significant sensitivity of the resultant impact from changes in the model, it is inappropriate for Ofgem to base this large demand-driven adjustment on this one model.

The significant sensitivity of the outcome to how the adjustment is derived, suggests that a valid approach would be to ask DNOs to provide cost estimates under different LCT assumptions. These revised cost estimates could then be used in the benchmarking to ensure that they are efficient.

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[61] We also note that assumptions around LCTs can affect cost drivers, such as peak demand or MEAV, not just costs. This needs careful investigation.

5 Ofgem's overall proposed approach to setting DNOs' efficiency challenge

In the DDs, Ofgem has proposed moving the catch-up efficiency challenge from a 75th percentile benchmark, as used at ED1, to an 85th percentile benchmark (with glidepath from the 75th percentile). This efficiency challenge is only applied to the three TOTEX models, which have an equally shared combined weight of 50% (i.e. 16.67% each), while the remaining 50% is assigned to the disaggregated models. Each disaggregated model uses comparisons to the average or median and each result is then summed.

5.1 Choice of benchmark, model and data inaccuracy

5.1.1 Choice of benchmark for the TOTEX models

Ofgem attempts to justify the move away from the ED1 upper quartile efficiency benchmark in several ways. However, these justifications are not valid and do not take into account the differences between price controls.[62]

Ofgem's main argument calls for consistency with the approach it adopted for the efficiency challenge in GD2. However, there are several issues with this comparison, as described below.

- Consistency in choice of percentile for the benchmark between two different sectors may be indicative but is not a robust basis on which to rely solely or primarily for the choice of the benchmark. The two sectors are very different, with different cost bases, and completely different issues and challenges over the next regulatory period. Indeed, in the appeal of PR19, the CMA stated that the regulators 'are regulating different sectors with different companies, so there is limited read across'—the same is true here.[63]

- Deciding on the appropriate benchmark should be based on the context of the cost assessment undertaken and primarily on the quality of the data and models. Indeed, in the PR19 appeal, when deciding on the issue of the appropriate benchmark, the CMA stated, 'we considered the overall model effectiveness and whether there had been substantial improvements in the econometric modelling',[64] while 'we placed little or no weight' on various other factors[65] and 'we found it was more appropriate to set the efficiency challenge based on our assessment of the quality of the econometric modelling, rather than to seek specific outcomes'.[66]

- Consistency in methodology does not result in consistency in the resultant implied challenge. The absolute level of challenge is very different between ED2 and GD2. Indeed, it was not disputed in GD2 that 'the effect of the choice of efficiency benchmark was small for the GDNs in RIIO-2'.[67]

[62] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, para. 7.441.
[63] CMA (2021), 'Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations', 17 March, para. 4.493.
[64] CMA (2021), 'Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations', 17 March, para. 4.492.
[65] as the factors include: regulatory precedent, the absolute level of efficiency challenge, past outperformance, comparisons of the companies' business plans with the modelled allowances, and the argument that monopolies may be less efficient than companies operating in competitive sectors.
[66] CMA (2021), 'Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations', 17 March, para. 4.493.
[67] CMA (2012), 'Cadent Gas Limited, National Grid Electricity Transmission plc, National Grid Gas plc, Northern Gas Networks Limited, Scottish Hydro Electric Transmission plc, Southern Gas Networks plc and Scotland Gas Networks plc, SP Transmission plc, Wales & West Utilities Limited vs the Gas and Electricity Markets Authority. Final determination Volume 3: Individual Grounds', October, para.12.133.

- Model quality in ED2 is materially lower than in GD2. The average adjusted R^2 of Ofgem's TOTEX models in ED2 is 0.84, as opposed to 0.93 in GD2 (where a similar approach of glidepath from 75th percentile to 85th percentile was used). See also sections 5.1.3 and 5.1.4.

- Uncertainty and issues related to data quality (e.g. the data issues with peak demand and LCT number for SSEN—a summary of issues is provided in SSEN's annex 5) also call for a less challenging approach, an aspect reinforced by the use of multiple models (as opposed to the single regression in GD2).

A more relevant comparison is with ED1 (where a 75th percentile benchmark was used). Although even here, the next control period is one of far greater uncertainty than ED1, with net zero challenge and very significant and uncertain EV/HP take-up. This would suggest a less challenging efficiency benchmark for ED2 than ED1. The average adjusted R^2, at 0.84 for ED2 is lower than the 0.88 in ED1. This again indicates that a less challenging benchmark than the 75th percentile benchmark should be used for ED2.

Additional analysis should be carried out to support the choice of benchmark. This includes stochastic frontier analysis (SFA) and an analysis of confidence intervals to examine the accuracy (or inaccuracy) of the models.

Materiality of impact

Another point raised by Ofgem is the 'relatively small' impact of this change, 'particularly when applied as a glide path to the 85th percentile'.[68] This statement is a clear error of fact, the impact is clearly significant and results in a far greater additional efficiency challenge in ED2 than in GD2. For example, the overall impact of this approach in ED2 is 0.7% of baseline allowances, compared to 0.1% in GD2. In monetary terms, the impact on SSEN is £24.3m for the ED2 period.

This greater challenge from the same benchmark choice is itself driven by the poorer fit and greater dispersion for efficiency scores, which are reflective of the materially greater inaccuracy of Ofgem's ED2 models compared to the GD2 models.

Ofgem's use of a range of models

Ofgem argues that it has benchmarked the DNOs' plans using a range of models, including models that include capacity released as a cost driver. However, this does not necessarily mean that the outcome is more accurate as a result.

Moreover, while the introduction of new models, each constructed using different activity drivers and time periods, is presented as diversifying the modelling base, it also potentially introduces additional uncertainty, especially as some of the proposals are being presented for the first time.[69]

As we evidence below, Ofgem's models are less accurate at predicting costs than those used in ED1, where a 75th percentile benchmark was used, which further demonstrates that Ofgem's decision to move to an 85th percentile benchmark is not justified for ED2.

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[68] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', 29 June, para. 7.441.
[69] We note that according to SSEN, the DNOs had asked for simpler modelling, as well as pooling of costs to cover assessments that overlap.

Impact of two price controls

Ofgem also 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.

This is a purely speculative and unevidenced argument by Ofgem. The opposite could also be argued. Indeed, the opposite conclusion is more likely (unless Ofgem's regulatory regime has not incentivised the desired outcomes). As DNOs are incentivised to improve their efficiency and catch up to the efficiency frontier, the true relative efficiency gap reduces over time and noise or modelling error becomes a larger proportion of the observed gap to the benchmark. As such, the catch-up benchmark should become less challenging over time.

5.1.2 Choice of benchmark for the disaggregated models

The benchmark for the disaggregated modelling is invalid. This results in an outcome that is even more stretching than that derived from the TOTEX modelling, despite taking the use of a median unit cost in each of the cost areas as the reference. The issue arises once the disaggregated results are summed to provide an overall position.

All companies are currently facing an efficiency challenge under disaggregated modelling—with the most efficient DNO being set an efficiency challenge of 1.5%. That is, *the catch-up benchmark is being set beyond current best practice* to a hypothetical position that no DNO currently achieves. This is a clear error in the exercise of regulatory discretion, taken without appropriate supporting evidence and runs counter to regulatory precedent and the core purpose of comparative efficiency analysis (whereby inefficiency relative to current best practice is identified).

In contrast, while all companies receive a challenge under disaggregated modelling, under the TOTEX modelling, the two companies better than the 85th percentile do not have any efficiency challenge. Across the sector, only two DNOs have a lower efficiency challenge in the disaggregated model than the TOTEX modelling and this is driven by the use of a hypothetical benchmark.

At the very least the overall disaggregated benchmark should be set at the most efficient company level. However, setting a benchmark at best practice does not account for any model and data inaccuracy. Shifting the overall benchmark to a percentile-based benchmark for disaggregated modelling as well as for TOTEX would set a more appropriate challenge. In fact, a similar approach to that used in ED1 should instead be used—namely, **the results from both the TOTEX models and disaggregated models should first be aggregated and then a 75th percentile benchmark should be applied**.[70]

5.1.3 Sensitivity of the ED2 TOTEX models

Modelling outcomes vary significantly when constructing the TOTEX cost drivers in alternative ways. We conducted principal component analysis (PCA)[71] on the cost drivers that Ofgem uses to construct the CSV and replaced

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[70] Ofgem (2014), 'RIIO-ED1: Final determinations for the slowtrack electricity distribution companies Business plan expenditure assessment. Final Decision', November, Figure 3.1.
[71] PCA is method of reducing the number of dimensions in a systematic way while maximising variance captured.

them with principal components. In some cases the R^2 value improved compared to Ofgem's models using CSV.

Costs predictions were very sensitive to this change, and changes in the number of principal components—varying, on average, by £15m–£30m. By comparison, changing the catch-up efficiency benchmark from the 85th to 75th percentile results in an average change of around £10m. As such, a material proportion of the observed differences in estimated efficiency are due to model uncertainty/noise as opposed to actual differences in efficiency.

### 5.1.4 Accuracy of ED2 TOTEX models

While TOTEX models 1 and 2 have an R^2 comparable to ED1 levels (with R^2 values of 0.86 and 0.84, respectively, as opposed to around 0.88 in ED1), model 3's explanatory power is markedly lower (with an adjusted R^2 of 0.80).

The lower explanatory power of model 3 is partly due to the shorter time period included in the regression (2022–28, as opposed to 2016–28 in the others), as it only includes forecast years. Indeed, basing a model exclusively on forecast data implies a greater degree of unreliability in the estimates than is evident in the R^2 given the greater uncertainty in the data, especially when they concern dynamics outside of a DNO's control. Lastly, the use of a composite LCT driver in model 3, which forecasts the number of EVs and HPs that will be connected to the grid, further exposes the model to the figures' uncertainty.

In line with the analysis of adjusted R^2 (86% for TOTEX model 1, 84% for model 2 and 80% for model 3), the confidence intervals support similar conclusions, with TOTEX model 1 being the best performing and model 3 the worst.

Moreover, the confidence intervals of the predicted expenditures vary significantly across DNOs. In particular, SSEH has the widest confidence interval for model 1 and is markedly above the industry average for models 2 and 3, as shown in Figure 5.1, thus implying that the models are less effective at predicting SSEH's expenditure (SWALES' costs are also relatively inaccurately predicted).

Figure 5.1   Average ED2 95% confidence intervals of predicted expenditures as a share of predicted costs
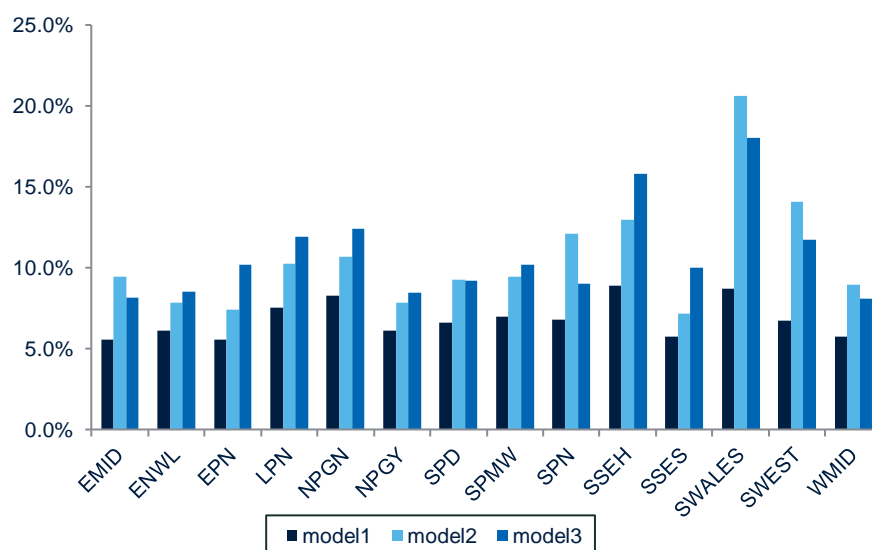
Source: Oxera analysis of Ofgem data.

5.2 Weighting between the three TOTEX models and the disaggregated model

Ofgem applies an equal weight between the TOTEX and the disaggregated modelling. It also puts an equal weight on each of the three TOTEX models without justifying this approach. Our concerns with this approach are as follows.

- Model 1 is different in nature from models 2 and 3. Model 1 has a bottom-up CSV, while models 2 and 3 are top-down CSVs. Similarly, model 1 relies on a CSV only, while 2 and 3 are extended to include, in addition to the top-down CSV, capacity released and a composite LCT uptake variable. As such, models 2 and 3 can be considered as alternative top-down TOTEX models and model 1 as a bottom-up TOTEX model.

- The differences in industry predicted costs are larger between TOTEX model 1 and TOTEX models 2 or 3 than between models 2 and 3, which appear to provide more similar outcomes. The gap between model 1 and models 2 or 3 is £137m and £210m, respectively, while it is up to three times lower between models 2 and 3, £73m.

- Consequently, our view would be to first apply the average between models 3 and 2 and then apply a 50% weighting with model 1. In other words, that would mean a 50% weight on model 1 and a 25% weight for each of the other two models.

This would result in an allowance increase of £2.7m for SSEH and £3.9m for SSES.

6 Ongoing efficiency

Our analysis of OE is set out in a separate document.[72] The main points are summarised here. Ofgem's 1.2% OE challenge is inappropriate. It is supported by a single data point—from a value added total factor productivity (VA TFP) model using an expanded comparator set over the full time period—all other results estimated by Ofgem's consultants, CEPA, do not support this result. The specific errors in Ofgem's selection of 1.2% are as follows.

- The full period is not a business cycle (the CMA recognises the need for business cycles), so the 1.2% estimate is derived from invalid modelling. 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.

- CEPA argues that the digital evolution might allow the DNOs to realise higher rates of productivity growth 'somewhat closer'[73] to that achieved in more digitally enabled industries. Yet this is already reflected by the wider comparator set (and the market economy). The OE challenge for electricity distribution should not be more stretching beyond the one supported by empirical evidence.

- Gross output total factor productivity (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.

- CEPA and Ofgem downplay the impact of actual productivity trends, arguing that the regulation provides protection. The operational reality is different. A DNO's workforce is confronted with COVID-19 like any other industry. While focused on delivering net zero, a significant undertaking for DNOs, achieving greater OE improvements than other sectors is not possible.

The impact of a 1%[74] OE challenge compared to a 1.2% level is a change in the cost challenge of £11.4m for SSEH and £23.4m for SSES.

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[72] Oxera (2022), 'Review of Ofgem's ongoing efficiency proposal in the RIIO-2 Draft Determinations', August.
[73] CEPA (2022), 'RIIO-ED2: Cost Assessment – Frontier Shift methodology paper', June, p. 22.
[74] That corresponds to the most stretching OE level proposed by the DNOs. This is also in line with previous water and energy appeals.

7   Overall achievability and summary of results

7.1   Achievability

Ofgem's DDs propose significant cuts to SSEN's forecast costs—around 22%. This is driven by a number of errors (as set out above) and Ofgem's unevidenced policy decisions. The OE target of 1.2% is above precedent and not supported by the evidence base, the catch-up target has been pushed unreasonably to the 85th percentile, the interpolation of efficient costs (between Ofgem's view and the DNOs' view) that was used in ED1 has been removed, and significant volumes have either been cut and/or placed in uncertainty mechanisms. These material cuts and increased uncertainty come at a time when increased spending is required to meet net zero targets.

Investments are needed for the transition to a net zero energy system, for the infrastructure to keep pace with the increasing demand, to enable DNOs to develop new business models in a decarbonised economy, to ensure resilience of the networks for severe weather events occurring more frequently, and to ensure the quality standards. The context for this price control, a challenging and evolving environment, is one in which **the regulatory focus should be on encouraging and ensuring delivery of net zero and not pushing the efficiency challenge to a level that could discourage investment and/or risk delivery**.

Moreover, these investments should not be considered as 'process innovation' to reduce costs and increase the efficiency challenge, but as necessary for 'product innovation' for the transition to net zero.[75] An adequate level of investment to meet the targets and allow the transition should be considered as necessary and not approached from an efficiency perspective.

Policymakers have highlighted the need for increased network development. For instance, BEIS' Energy White Paper states that:[76]

> [t]he transformation of our energy system will require growing investment in physical infrastructure, to extend or reinforce the networks of pipes and wires which connect energy assets to the system and maintain essential resilience and reliability. As well as creating a low-carbon system we need enhanced preparedness for climate risks.

In light of this, **Ofgem's proposal to apply a more-than-20% cut to SSEN's costs may render the DDs unachievable and risks leaving insufficient funding for much-needed investment.**

SSEN also states that, in specific geographic areas like the islands, these investments are needed even more to ensure quality standards.[77] For instance, restoring subsea cables supply is critical to minimise the negative impacts on customers and to reduce the need for remote generators.

Moreover, in these same areas, SSEN highlights that some investments are instrumental to enabling the deployment of the high potential to contribute to net zero government targets that these areas can provide, both in terms of renewables and of electrification of consumption.[78] The geography of these

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[75] See Oxera (2022), 'Review of Ofgem's ongoing efficiency proposal in the RIIO-2 Draft Determination', August, para. 2.12.
[76] BEIS (2020), 'Energy white paper – powering our net zero future', December, Chapter 3.
[77] SSEN (2022), 'RIIO-ED2 North of Scotland', August.
[78] Ibid.

areas can contribute to maximising the potential of renewables and accelerating the transition, but with higher complexity and costs.

At the same time, the quality targets have not been reduced compared to previous price controls—if anything, they have increased. For instance, network asset resilience measures (NARMs) have been cut significantly but the same output retained (in terms of risk reduction to be achieved on SSEN's network). The CMA has been clear on the cost:quality relationship on multiple occasions in the past—most recently at PR19. The CMA has accepted that additional allowances are needed for delivering high quality, both for base costs and enhancements. It states that:[79]

> [w]e have 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 […] We decide to adjust the base cost allowance for Anglian, according to its stated base expenditure requirements in proportion to its outperformance on leakage.

Similarly, the CMA concluded that 'further allowances were needed to meet the ambitious leakage PCs [Performance Commitments] and should be allocated an allowance for the efficient costs of these enhancements'.[80]

Overall, there is a clear risk that the allowances proposed in the DDs are insufficient and not achievable. A breakdown of the errors found in this report is provided in the next sub-section.

7.2   Summary of results

This report finds a number of errors and areas for improvement in the cost assessment approach proposed in Ofgem's DDs. These errors need to be corrected at FD in order to arrive at robust allowances that reflect efficient costs, thereby allowing DNOs to carry out the necessary investment to provide a safe, resilient and net-zero-ready network.

A summary of the impact of our findings is provided below. These are based on the analysis carried out as part of this report. Some areas, especially those requiring engineering knowledge, have not been assessed in this report and are therefore not presented here. Given the limited time available to review Ofgem's modelling suite, there may be additional issues that we subsequently identify and that will need to be raised with Ofgem prior to the FD.

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[79] CMA (2021), 'Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations ', 17 March, para. 79.
[80] Ibid.

Table 7.1   Impact of proposed adjutsments in Ofgem's modelling (£m)

	Ofgem DDs	Corrected data	HVP	OE	CAI/BSC cost driver	Upper quartile benchmark	Re-weighting TOTEX models	Catch-up efficiency challenge applied to the disaggregated model[1]	Sparsity[2]	Regional wages	Total	Combined[3]
ENWL	1,714	0.6	-	17.4	-7.2	13.0	-2.1	53.5	1.1	-12.1	64.2	73.0
NPGN	1,181	0.9	-	12.2	-2.1	8.5	-5.6	36.1	3.8	-10.7	43.1	48.5
NPGY	1,591	1.4	-	16.5	-5.9	11.5	-4.2	48.8	1.7	-11.1	58.7	66.1
WMID	1,659	1.4	-	16.8	1.5	11.5	2.6	50.1	1.0	-11.1	73.8	83.8
EMID	1,773	1.8	-	17.9	-2.2	12.7	4.7	54.3	0.0	-10.6	78.6	89.6
SWALES	996	1.0	-	10.1	9.0	7.0	7.7	30.2	4.3	-10.2	59.1	65.2
SWEST	1,404	0.8	-	14.2	14.6	9.5	9.7	41.8	2.5	-12.6	80.5	89.2
LPN	1,382	0.4	-	14.0	-25.5	11.0	-5.8	42.4	2.8	-8.8	30.5	38.9
SPN	1,457	0.7	-	14.8	-6.3	11.2	-4.4	46.0	2.3	-8.7	55.6	63.4
EPN	2,233	0.8	-	22.6	3.7	16.8	4.4	69.5	-3.5	-10.8	103.5	115.1
SPD	1,516	0.9	-	15.4	-1.6	10.9	-2.9	46.5	2.2	21.4	92.8	103.3
SPMW	1,543	1.4	-	15.6	4.1	10.4	0.0	45.9	3.5	-11.9	69.0	79.3
SSEH	**1,134**	**16.4**	**15.7**	**11.4**	**17.2**	**8.3**	**2.7**	**35.6**	**15.0**	**11.9**	**134.2**	132.0
SSES	**2,295**	**28.4**	**-**	**23.4**	**-0.7**	**16.0**	**3.9**	**69.3**	**3.2**	**-6.4**	**137.1**	150.2

Note: Ofgem's DD allowance refers to efficient costs + bespoke outputs and technical assessments + uncertainty mechanism costs + pass-through items + BPI reward/ penalty, including OE and RPEs. The impact of the proposed changes in the tree-cutting approach is not included in this table as the impact has only been derived for SSEN. However, as mentioned in section 3.1.4, those changes would lead to a further allowance increase of £7.5m and £9.4m, respectively, for SSEH and SSES. [1] Derived by keeping a glide path from the 75th to the 85th percentile. [2] The sparsity impact has been estimated for the TOTEX models only. Further pre-modelling adjustment would be needed for a number of the disaggregated models, which would increase the impact of this adjustment. [3] Combining a UQ benchmark with the application of a catch-up efficiency challenge to the disaggregated model implies a higher impact than summing both effects individually which is why the combined impact appears higher than the sum of the impact of each adjustment taken individually.

Source: Oxera analysis based on Ofgem's Allowance_File_ED.xlsx, tab 'Out_Allow', AO318-AO331.