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RIIO-ED1: Final determinations for the slow-track electricity distribution companies

Business plan expenditure assessment

Final decision

Publication date: 28 November 2014

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Overview:

This document describes our methodology for the assessment of the business plan expenditure and results for the expenditures proposed in the settlement (final determinations) for the ten electricity distribution companies remaining in the price control review. The final determinations are for the next price control (RIIO-ED1).

We have published this supplementary annex to provide further detail on our assessment of the companies' forecasts expenditures. Our assessment is summarised in the Overview document.

Associated documents

RIIO-ED1: Final determinations for the slow-track electricity distribution companies – Overview
https://www.ofgem.gov.uk/publications-and-updates/riio-ed1-final-determinations

RIIO-ED1: Final determinations for the slow-track electricity distribution companies – supplementary annexes

- RIIO-ED1 business plan expenditure assessment
- RIIO-ED1 final determinations RPE methodology decision
- RIIO-ED1 final determinations Financial Model
- RIIO-ED1 final determinations detailed figures by company

The supplementary annexes are on our website:
https://www.ofgem.gov.uk/publications-and-updates/riio-ed1-final-determinations

RIIO-ED1: Draft determinations for the slow-track distribution companies
https://www.ofgem.gov.uk/ofgem-publications/89076/riioed1draftdeterminationoverview30072014.pdf

Decision to fast-track Western Power Distribution
https://www.ofgem.gov.uk/ofgem-publications/86375/fast-trackdecisionletter.pdf

Assessment of RIIO-ED1 business plans and fast-tracking
https://www.ofgem.gov.uk/ofgem-publications/84600/assessmentofriio-ed1businessplansletter.pdf

Timing of decision on electricity distribution networks' revenue for 2015-16
https://www.ofgem.gov.uk/ofgem-publications/86768/ed1revenuechangedecision.pdf

Decision on our methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls
https://www.ofgem.gov.uk/publications-and-updates/decision-our-methodology-assessing-equity-market-return-purpose-setting-riio-ed1-price-controls

Strategy Decision for RIIO-ED1 – Overview
https://www.ofgem.gov.uk/publications-and-updates/strategy-decision-riio-ed1-overview

Contents

1. Introduction

Overview

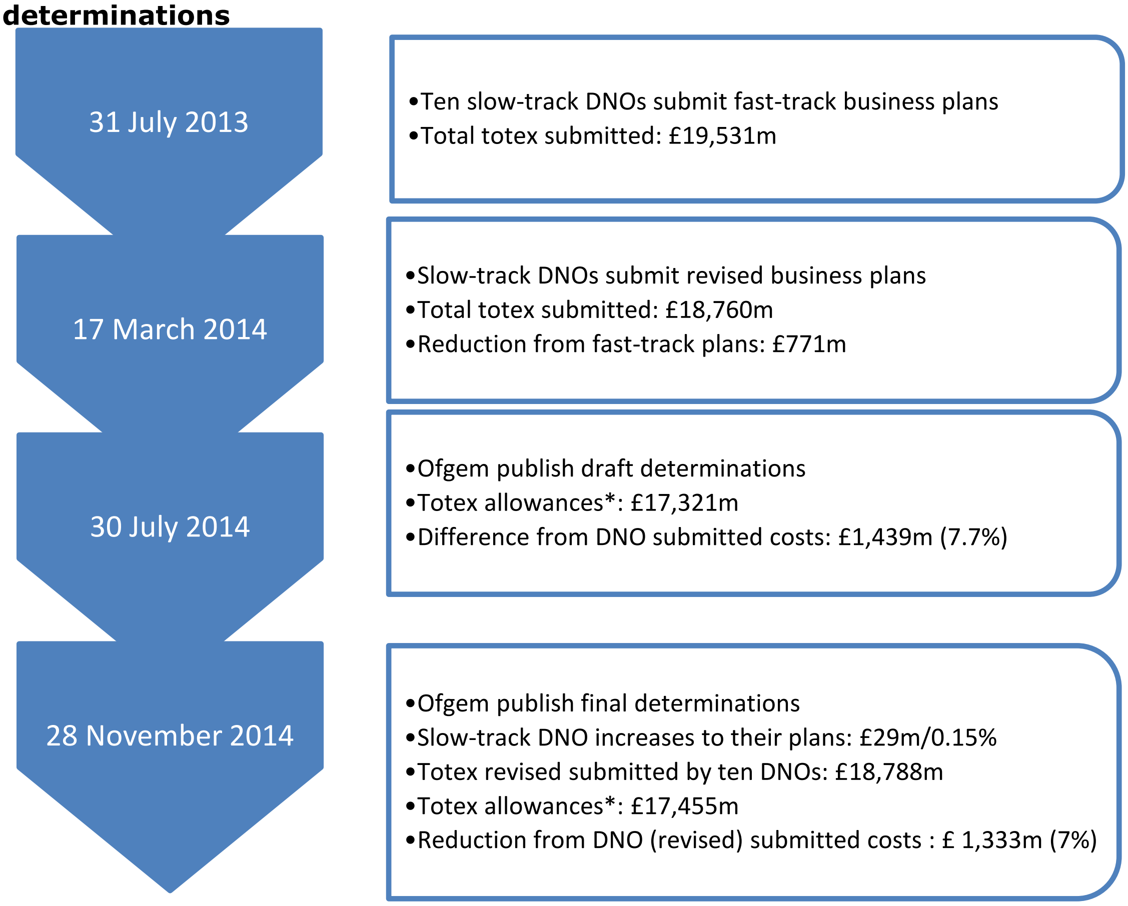
1.1. Following our decision to fast-track the four distribution network operators (DNOs) owned by Western Power Distribution (WPD), the remaining ten DNOs submitted their revised business plans for RIIO-ED1 in March 2014. We assessed these revised plans and published our draft determinations in July. This included a detailed annex on our approach to assessing efficient expenditure.

1.2. DNOs and other stakeholders responded to our draft determinations. DNOs also raised issues in letters and during bilateral discussions. We considered the issues raised and made changes to our approach where there was justification for doing so. We explain our approach to setting the efficient expenditure allowances for final determinations in this annex.

1.3. As summarised in Figure 1.1, the ten slow-track DNOs submitted costs of £19,531m in July 2013 for fast -track. They reduced their submission by £742m (3.8%) ahead of final determinations. Allowances at final determinations are £17,455m (including real price effects (RPEs) and smart grids adjustments).[1] We disallow £1,333m (7%) of submitted costs. Final determinations allowances are £134m more than at draft determinations (£17,321m).

[1] Allowances are based on 75% Ofgem view and 25% DNO view of costs.

Figure 1.1: Summary of submitted and allowed costs from fast-track to final determinations



* Totex allowances are based on 75% Ofgem view and 25% DNO submitted costs.

Structure of this document

1.4. For the majority of chapters we use the following structure:

- the decision taken for final determinations and the results of our assessment
- our approach at draft determinations
- key stakeholder comments on the draft determinations[2]
- reasons for the decision.

1.5. All forecast data reported in Chapters 6 to 10 is net before any normalisations (ie simply as submitted by the DNOs). The modelled view of submitted costs is net post reversal of normalisations, but before the application of RPEs, smart grids adjustments and the interpolation under the Information Quality Incentive (IQI).

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[2] Almost all responses to the efficient expenditure annex came from the DNOs. This is not surprising given that this is a technical document. Other stakeholders responded to the higher level questions on cost assessment set out in our overview document.

1.6. Figure 1.2 provides a high level overview of the stages of our cost assessment with the chapters which provide the detail on each stage.

Figure 1.2: Stages of our cost assessment approach and relevant chapters

Stage 1: Review and normalise all data. Exclude relevant data from the models.	Chapter 4
Stage 2: Run both totex models and the disaggregated model	Chapter 3 for summary Chapter 5 for totex models Chapters 6 to 10 for disaggregated models Appendix 3 for approach to econometric benchmarking Appendix 4 for statistical tests and regression results Appendix 5 for the calculation of the CSVs
Stage 3: Combine the results of 3 models	Chapter 3
Stage 4: Calculate and apply upper quartile	Chapter 3
Stage 5: Apply smart grids and RPE adjustments	Chapters 11 and 12

Notes

1.7. It is important to note the following when reading this document:

- the slow-track assessment (for both draft and final determinations) is different to the fast-track assessment in many areas and we would expect differences in results
- all DNOs except the four WPD companies have had the opportunity to resubmit data and justifications between fast-track and slow-track, again leading to an expectation of different results
- the WPD DNOs have been included in our cost assessment to provide a larger dataset. This improves the statistical benchmarking, the comparative assessment of unit cost and volumes, and the comparative assessment of the narratives provided by all DNOs
- we describe the WPD DNOs in the assessment in a similar manner to the ten slow-track DNOs, but this is only for reference. The slow-track assessment does not change WPD’s fast-track settlement. Any figures presented in tables that relate to the four WPD licensees have been shaded in grey to reflect this.

DNO acronyms

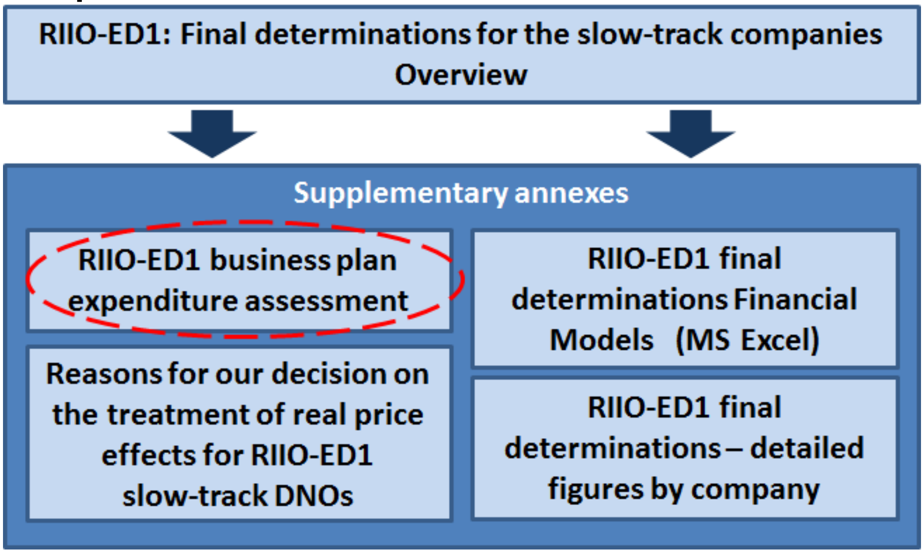
1.8. Table 1.1 provides a list of the DNO acronyms used in this annex.

Table 1.1: DNO acronyms

DNO Group		DNO	
ENWL	Electricity North West Limited	ENWL	Electricity North West Limited
NPg	Northern Powergrid	NPgN	Northern Powergrid: Northeast
		NPgY	Northern Powergrid: Yorkshire
WPD	Western Power Distribution	WMID	Western Power Distribution: West Midlands
		EMID	Western Power Distribution: East Midlands
		SWALES	Western Power Distribution: South Wales
		SWEST	Western Power Distribution: South West
UKPN	UK Power Networks	LPN	UK Power Networks: London Power Networks
		SPN	UK Power Networks: South East Power Networks
		EPN	UK Power Networks: Eastern Power Networks
SPEN	SPEN Energy Networks	SPD	SPEN Energy Networks: Distribution
		SPMW	SPEN Energy Networks: Manweb
SSEPD	Scottish and Southern Energy Power Distribution	SSEH	Scottish and Southern Energy Power Distribution: Scottish Hydro Electric Power Distribution
		SSES	Scottish and Southern Energy Power Distribution: Southern Electric Power Distribution

1.9. Figure 1.3 below shows all the RIIO-ED1 documents we have published today. There are links to all these documents in the ‘Associated Documents’ section at the top of this document.

Figure 1.3: Map of the RIIO-ED1 final determinations documents



2. Headline results

Chapter summary

High level results of our RIIO-ED1 cost assessment, followed by more detailed results for each DNO.

2.1. Our final determinations allowances for totex are intended to be reasonable allowances for the DNOs in RIIO-ED1. We use a toolbox approach to assess efficient costs recognising that there are many ways of assessing what is appropriate. Similarly, our use of upper quartile (UQ) benchmarking (rather than frontier) and IQI interpolation (where we use 75% our view and 25% DNO's view) recognise we do not have perfect information. We believe our final determinations are appropriate. We do not intend to make any further changes.

High level results

2.2. All slow-track DNOs, except LPN and NPgN, reduced their expenditure from fast-track to slow-track final determinations.[3] All DNOs took steps to improve the quality of their justification compared to fast-track, with further justification provided after draft determinations. Table 2.1 shows that the ten slow-track DNOs reduced their requested totex by £742m in total.

2.3. Overall the slow-track DNOs increased their submitted costs by £29m since draft determinations. Three made no changes, four increased and three reduced their costs. Details of these changes are in Table 2.2. The March submitted totex is the total costs submitted ahead of draft determinations. The final submitted totex is the post draft determinations revisions. All our submitted costs exclude rail electrification costs.

[3] Both NPgN and NPgY increased their submitted costs from fast-track to slow-track by including ex ante costs for the costs of diversions caused by Networks Rail's electrification programme which were not included at fast-track. These costs are not included in our modelling.

Table 2.1: Fast-track and slow-track submitted totex (2012-13 prices)

DNO	Fast-track submitted totex (£m)	Slow-track March submitted totex (£m)	Slow-track final submitted totex (£m)*	Slow-track March submitted totex minus fast-track submitted totex (£m)	Slow-track final submitted totex *minus* slow-track March submitted totex (£m)	Slow-track final submitted totex minus fast-track submitted totex (£m)
ENWL*	1,900	1,877	1,876	-23	-1	-24
NPgN	1,365	1,362	1,368	-2	6	4
NPgY	1,859	1,810	1,805	-49	-5	-55
WMID	2,070	2,070	2,070	0	0	0
EMID	2,084	2,084	2,084	0	0	0
SWALES	1,080	1,080	1,080	0	0	0
SWEST	1,693	1,693	1,693	0	0	0
LPN	1,968	1,961	1,970	-7	9	2
SPN	1,897	1,859	1,872	-39	13	-26
EPN	2,861	2,765	2,775	-96	10	-86
SPD	1,740	1,564	1,563	-176	-1	-177
SPMW	2,220	1,927	1,924	-293	-3	-297
SSEH	1,230	1,210	1,210	-20	0	-20
SSES	2,490	2,425	2,425	-65	0	-65
Total	26,457	25,686	25,715	-771	29	-742
Total excluding WPD	**19,531**	**18,760**	**18,788**	**-771**	**29**	**-742**

* We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.
** ENWL did not decrease its slow-track submission by £1m from draft to final determinations. The £1m was due to rail electrification costs being wrongly included in the March figures.

Table 2.2: Detail of changes to submitted costs from draft to final determinations[4]

DNO	Total change (£m)	Activities affected
ENWL	-0.8	-£0.8m in diversions
NPgN	6.1	-£16.4m connections +£20.4m reinforcements +£2.1m transmission connection point charges
NPgY	-5.4	-£11.3m critical national infrastructure (CNI) +£5.9m legal and safety
LPN	9.2	+£6.2m asset replacement +£0.4m legal and safety +£2.0m inspections and maintenance +£0.6m CNI
SPN	13.0	+£8.2m asset replacement +£0.3m legal and safety +£1.4m inspections and maintenance +£1.1m CNI +£2.1 losses and environmental
EPN	10.4	-£0.1m connections -£0.1m diversions +£0.1 ESQCR +£3.9m asset replacement -£0.2 refurbishment +£0.2 civils +£0.1m legal and safety +£2.1 environmental +£1.9m inspections and maintenance +£1.7m CNI +£0.1m occurrences not incentivised (ONIs) +£0.5m closely associated indirects (CAIs) +0.1m business support costs (BSCs)
SPMW	-3.4	-£3.4m blackstart

2.4. We have used three economic models for our benchmarking: a top-down totex model using high level drivers, a bottom-up totex model using an aggregated driver based on the drivers used in the disaggregated analysis, and a disaggregated activity based model.

2.5. In reaching our overall results, we place 50% weight on the totex models (25% for the top-down and 25% for the bottom-up totex model) and 50% on the disaggregated model.

2.6. We present the following combined results by DNO and by group:

- our view of the comparative cost assessment efficient expenditure, before the application of RPEs and smart grid savings
- our view of efficient expenditure after the application of RPEs and smart grid savings
- the final determinations expenditure allowance after IQI interpolation
- the difference between DPCR5 spend and our final determinations allowance for RIIO-ED1 expenditure (on an average annual basis).

[4] UKPN increased its forecasts by over £95m associated with link boxes and then also made other changes for CNI. We have only put through the first two years of their increased link box forecasts into the final BPDTs to avoid them being penalised under the IQI. The remaining years are dealt with under an uncertainty mechanism. Link box costs affect asset replacement, legal and safety and inspections and maintenance costs.

2.7. Tables 2.3 (by DNO) and 2.4 (by group) show the results of our comparative cost assessment, prior to the application of RPEs and smart grids adjustments.

2.8. Tables 2.5 (by DNO) and 2.6 (by group) include RPEs and smart grids adjustments. They also compare our modelled costs to the fast-track and the slow-track submissions.

Table 2.3: Results of cost assessment prior to the application of RPEs and smart grid savings – by DNO (2012-13 prices)

DNO	Slow-track final submitted totex excluding RPEs*	Modelled costs before the application of the UQ				Modelled post-UQ and pre-smart grids adjustment and RPEs	Difference (modelled minus submitted)		Efficiency scores before smart grid adjustment and RPEs
	£m	Top-down totex £m	Bottom-up totex £m	Disagg activity level analysis £m	Combined based on 25%/25%/50% weighting £m	£m	£m	%	
ENWL	1,794	1,934	1,885	1,836	1,873	1,810	17	1%	0.99
NPgN	1,334	1,351	1,330	1,241	1,291	1,248	-86	-6%	1.07
NPgY	1,752	1,790	1,800	1,669	1,732	1,674	-78	-4%	1.05
WMID	1,931	1,880	1,876	1,884	1,881	1,818	-113	-6%	1.06
EMID	1,945	2,099	2,060	1,939	2,009	1,942	-2	0%	1.00
SWALES	1,011	1,079	1,077	1,046	1,062	1,026	15	2%	0.98
SWEST	1,583	1,396	1,446	1,552	1,486	1,437	-146	-9%	1.10
LPN	1,892	1,837	1,784	1,767	1,788	1,729	-164	-9%	1.09
SPN	1,796	1,817	1,776	1,702	1,749	1,691	-105	-6%	1.06
EPN	2,663	2,517	2,577	2,632	2,590	2,503	-160	-6%	1.06
SPD	1,495	1,662	1,653	1,562	1,609	1,556	60	4%	0.96
SPMW	1,837	1,592	1,616	1,783	1,694	1,637	-200	-11%	1.12
SSEH	1,145	1,095	1,103	1,144	1,121	1,084	-61	-5%	1.06
SSES	2,343	2,460	2,529	2,341	2,418	2,337	-6	0%	1.00
Total	24,521	24,507	24,513	24,098	24,304	23,493	-1,028	-4%	
Total excluding WPD	**18,051**	**18,053**	**18,053**	**17,678**	**17,865**	**17,269**	**-782**	**-4%**	

* The costs exclude RPEs to allow a direct comparison of modelled costs prior to the application of RPE savings. We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.

Table 2.4: Results of cost assessment prior to the application of RPEs and smart grid savings – by group (2012-13 prices)

DNO	Slow-track final submitted totex excluding RPEs*	Modelled costs before the application of the UQ				Modelled post-UQ and pre-smart grids adjustment and RPEs	Difference (modelled minus submitted		Efficiency scores before smart grid adjustment and RPEs
	£m	Top-down totex £m	Bottom-up totex £m	Disagg activity level analysis £m	Combined based on 25%/25%/50% weighting £m	£m	£m	%	
ENWL	1,794	1,934	1,885	1,836	1,873	1,810	17	1%	0.99
NPg	3,086	3,141	3,130	2,911	3,023	2,922	-164	-5%	1.06
WPD	6,469	6,453	6,460	6,420	6,438	6,224	-246	-4%	1.04
UKPN	6,351	6,170	6,136	6,101	6,127	5,923	-429	-7%	1.07
SPEN	3,332	3,253	3,269	3,345	3,303	3,193	-140	-4%	1.04
SSEPD	3,488	3,555	3,632	3,485	3,539	3,421	-67	-2%	1.02
Total	24,521	24,507	24,513	24,098	24,304	23,493	-1,028	-4%	
Total excluding WPD	**18,051**	**18,053**	**18,053**	**17,678**	**17,865**	**17,269**	**-782**	**-4%**	

* The costs exclude RPEs to allow a direct comparison of modelled costs prior to the application of RPE savings. We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.

Table 2.5: Results of cost assessment including RPEs and smart grid savings - by DNO (2012-13 prices)

DNO	Slow-track final submitted totex including RPEs*	Adjustment (a) result of cost assessment only		Adjustment (b) result of smart grid savings		Adjustment (c) result of RPEs		Ofgem modelled slow-track final determinations pre IQI**		Efficiency scores after smart grid adjustment and RPEs	Slow-track final determinations interpolated allowance
	£m	£m	%	£m	%	£m	%	£m	%		£m
ENWL	1,876	17	1%	-8	0%	-77	-4%	1,808	-4%	1.04	1,825
NPgN	1,368	-57	-4%	-21	-2%	-60	-4%	1,230	-10%	1.11	1,265
NPgY	1,805	-46	-3%	-21	-1%	-80	-4%	1,657	-8%	1.09	1,694
WMID	2,070	-113	-5%	-46	-2%	-134	-6%	1,777	-14%	1.16	1,851
EMID	2,084	-2	0%	-34	-2%	-134	-6%	1,914	-8%	1.09	1,956
SWALES	1,080	15	1%	-23	-2%	-67	-6%	1,006	-7%	1.07	1,024
SWEST	1,693	-146	-9%	-29	-2%	-106	-6%	1,411	-17%	1.20	1,482
LPN	1,970	-164	-8%	-29	-1%	-73	-4%	1,704	-14%	1.16	1,771
SPN	1,872	-105	-6%	-22	-1%	-71	-4%	1,673	-11%	1.12	1,722
EPN	2,775	-160	-6%	-53	-2%	-106	-4%	2,457	-11%	1.13	2,536
SPD	1,563	60	4%	-55	-4%	-64	-4%	1,505	-4%	1.04	1,519
SPMW	1,924	-200	-10%	-60	-3%	-83	-4%	1,581	-18%	1.22	1,667
SSEH	1,210	-68	-6%	-14	-1%	-37	-3%	1,092	-10%	1.11	1,121
SSES	2,425	-6	0%	-39	-2%	-76	-3%	2,304	-5%	1.05	2,334
Total	25,716	-974	-4%	-454	-2%	-1,169	-5%	23,119	-10%		23,768
Total excluding WPD	**18,788**	**-728**	**-4%**	**-322**	**-2%**	**-728**	**-4%**	**17,011**	**-9%**		**17,455**

* We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.

** Ofgem efficient view of totex in these tables is prior to interpolation. Our final view of DNO totex under the IQI mechanism is based on 75% of the Ofgem view and 25% of the DNO forecast.

Table 2.6: Results of cost assessment including RPEs and smart grid savings - by group (2012-13 prices)

DNO	Slow-track final submitted totex including RPEs*	Adjustment (a) result of cost assessment only		Adjustment (b) result of smart grid savings		Adjustment (c) result of RPEs		Ofgem modelled slow-track final determinations pre IQI**		Efficiency scores after smart grid adjustment and RPEs	Slow-track final determinations interpolated allowance
	£m	£m	%	£m	%	£m	%	£m	%		£m
ENWL	1,876	17	1%	-8	0%	-77	-4%	1,808	-4%	1.04	1,825
NPg	3,173	-103	-3%	-42	-1%	-141	-4%	2,888	-9%	1.10	2,959
WPD	6,927	-246	-4%	-132	-2%	-441	-6%	6,108	-12%	1.13	6,313
UKPN	6,617	-429	-6%	-104	-2%	-251	-4%	5,833	-12%	1.13	6,029
SPEN	3,487	-140	-4%	-115	-3%	-146	-4%	3,086	-11%	1.13	3,186
SSEPD	3,635	-74	-2%	-53	-1%	-113	-3%	3,396	-7%	1.07	3,456
Total	25,716	-974	-4%	-454	-2%	-1,169	-5%	23,119	-10%		23,768
Total excluding WPD	**18,788**	**-728**	**-4%**	**-322**	**-2%**	**-728**	**-4%**	**17,011**	**-9%**		**17,455**

* We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.
** Ofgem efficient view of totex in these tables is prior to interpolation. Our final view of DNO totex under the IQI mechanism is based on 75% of the Ofgem view and 25% of the DNO forecast.

2.9. The efficiency rankings of the companies in our final determinations (shown in the table below) are broadly in line with draft determination rankings. These rankings include smart grids benefits and RPEs.

Table 2.7: DNOs' efficiency rankings

Rank	Fast-track	Slow-track draft determinations	Slow-track final determinations
1	SWALES	SPD	ENWL
2	WMID	ENWL	SPD
3	EMID	SSES	SSES
4	SSES	EMID	SWALES
5	SWEST	NPgY	EMID
6	ENWL	SWALES	NPgY
7	SSEH	SPN	SSEH
8	NPgN	EPN	NPgN
9	SPN	NPgN	SPN
10	NPgY	SSEH	EPN
11	SPD	WMID	LPN
12	LPN	LPN	WMID
13	EPN	SPMW	SWEST
14	SPMW	SWEST	SPMW

2.10. The comparative cost assessment totex and disaggregated models have remained relatively stable from fast-track through draft and final determinations. The main factors driving the changes in the efficiency rankings are the changes in weightings on the models, the reductions in the slow-track DNOs forecasts in March and the assumptions for RPEs and smart grid savings.

2.11. The change in WPD's rankings between fast and slow-track is not surprising as the slow-track DNOs submitted revised costs and justifications. WPD's rankings have improved slightly between draft and final determinations because it clarified some of its numbers. It has also demonstrated that its smart grids benefits are greater than we originally assessed.

IQI and final determinations expenditure allowance

2.12. We have adjusted the break-even point in the IQI matrix to an IQI score of 102.9 rather than 100. This means that a DNO group that forecasts 2.9% above our efficient cost benchmark and achieves its forecast will earn its cost of capital but no additional reward or penalty.

2.13. Table 2.8 shows the IQI matrix for the slow-track assessment. Table 2.9 has the outcome of the IQI for each slow-track DNO group.

Table 2.8: IQI matrix

DNO:Ofgem Ratio	90	95	100	105	110	115	120	125	130
Efficiency Incentive	65%	63%	60%	58%	55%	53%	50%	48%	45%
Additional income (£/100m)	3.1	2.4	1.7	0.9	0.1	-0.8	-1.8	-2.8	-3.9
Rewards & Penalties									
Allowed expenditure	97.50	98.75	100.00	101.25	102.50	103.75	105.00	106.25	107.50
Actual Exp									
90	7.95	7.9	7.7	7.4	7.0	6.4	5.7	4.9	4.0
95	4.7	4.76	4.7	4.5	4.2	3.8	3.2	2.5	1.7
100	1.5	1.6	1.7	1.6	1.5	1.1	0.7	0.1	-0.6
105	-1.8	-1.5	-1.3	-1.2	-1.3	-1.5	-1.8	-2.2	-2.8
110	-5.1	-4.6	-4.3	-4.1	-4.1	-4.1	-4.3	-4.6	-5.1
115	-8.3	-7.7	-7.3	-7.0	-6.8	-6.7	-6.8	-7.0	-7.3
120	-11.6	-10.9	-10.3	-9.9	-9.6	-9.4	-9.3	-9.4	-9.6
125	-14.8	-14.0	-13.3	-12.7	-12.3	-12.0	-11.8	-11.7	-11.8
130	-18.1	-17.1	-16.3	-15.6	-15.1	-14.6	-14.3	-14.1	-14.1
135	-21.3	-20.2	-19.3	-18.5	-17.8	-17.2	-16.8	-16.5	-16.3
140	-24.6	-23.4	-22.3	-21.4	-20.6	-19.9	-19.3	-18.9	-18.6
145	-27.8	-26.5	-25.3	-24.2	-23.3	-22.5	-21.8	-21.2	-20.8
150	-31.1	-29.6	-28.3	-27.1	-26.1	-25.1	-24.3	-23.6	-23.1

Table 2.9: IQI results for the DNO groups (2012-13 prices)

DNO Group	IQI ratio	Upfront financial reward/penalty. Also total reward/penalty if companies spend at Ofgem's allowance		Total reward/penalty if companies spends in line with its forecast		Total reward/penalty if companies spends in line with Ofgem's benchmark	
		%	£m	%	£m	%	£m
ENWL	104	1.1%	20	-0.5%	-10	1.7%	30
NPg	110	0.1%	3	-4.0%	-115	1.5%	43
UKPN	113	-0.5%	-32	-5.9%	-345	1.2%	75
SPEN	113	-0.5%	-14	-5.7%	-175	1.3%	41
SSEPD	107	0.6%	20	-2.4%	-82	1.6%	54

2.14. Tables 2.10 and 2.11 present the final view of efficient expenditure after IQI interpolation at DNO and group level.

2.15. All slow-track DNOs and DNO groups have costs that we have judged inefficient. For the groups, this ranges from 103% for ENWL to 109% for UKPN and SPEN. On average the costs submitted by the slow-track DNOs' are 7% higher than our allowed costs.

2.16. The table compares the ranking at draft determinations (dd) and at final determinations (fd) by DNO and by group. The efficiency rankings do not change at a group level but there is some movement at the DNO level. The most notable shift is for SSEH which moves from 8th to 5th position.

Table 2.10: Final efficient expenditure - by DNO (2012-13 prices)

DNO	Fast-track submitted totex	Slow-track March submitted totex	Ofgem's view slow-track draft determinations pre IQI	Slow-track draft determinations allowance post IQI	Slow-track final submitted totex*	Ofgem's view slow-track draft determinations pre IQI	Slow-track final determinations allowance post IQI	Percentage reduction to slow-track submitted	Rank	
	£m	£m	£m	£m	£m	£m	£m	%	dd	fd
ENWL	1,900	1,877	1,766	1,794	1,876	1,808	1,825	-3%	2	1
NPgN	1,365	1,362	1,203	1,243	1,368	1,230	1,265	-8%	7	6
NPgY	1,859	1,810	1,643	1,685	1,805	1,657	1,694	-6%	4	4
WMID	2,070	2,070	2,070	1,850	2,070	2,070	2,070	0%	-	-
EMID	2,084	2,084	2,084	1,965	2,084	2,084	2,084	0%	-	-
SWALES	1,080	1,080	1,080	1,003	1,080	1,080	1,080	0%	-	-
SWEST	1,693	1,693	1,693	1,463	1,693	1,693	1,693	0%	-	-
LPN	1,968	1,961	1,678	1,749	1,970	1,704	1,771	-10%	9	9
SPN	1,897	1,859	1,661	1,710	1,872	1,673	1,722	-8%	5	7
EPN	2,861	2,765	2,461	2,537	2,775	2,457	2,536	-9%	6	8
SPD	1,740	1,564	1,504	1,519	1,563	1,505	1,519	-3%	1	2
SPMW	2,220	1,927	1,607	1,687	1,924	1,581	1,667	-13%	10	10
SSEH	1,230	1,210	1,059	1,097	1,210	1,092	1,121	-7%	8	5
SSES	2,490	2,425	2,260	2,301	2,425	2,304	2,334	-4%	3	3
Total	26,457	25,686	23,768	23,602	25,715	23,937	24,382	-5%		
Total excluding WPD	**19,531**	**18,760**	**16,841**	**17,321**	**18,788**	**17,011**	**17,455**	**-7%**		

* We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.

Table 2.11: Final efficient expenditure - by DNO group (2012-13 prices)

DNO	Fast-track submitted totex	Slow-track March submitted totex	Ofgem's view slow-track draft determinations pre IQI	Slow-track draft determinations allowance post IQI	Slow-track final submitted totex*	Ofgem's view slow-track draft determinations pre IQI	Slow-track final determinations allowance post IQI	Percentage reduction to slow-track submitted	Rank	
	£m	£m	£m	£m	£m	£m	£m	%	dd	fd
ENWL	1,900	1,877	1,766	1,794	1,876	1,808	1,825	-3%	1	1
NPg	3,224	3,172	2,846	2,928	3,173	2,888	2,959	-7%	3	3
WPD	6,926	6,926	6,926	6,281	6,926	6,926	6,926	-	-	-
UKPN	6,726	6,584	5,799	5,995	6,617	5,833	6,029	-9%	5	5
SPEN	3,960	3,491	3,111	3,206	3,487	3,086	3,186	-9%	4	4
SSEPD	3,720	3,635	3,319	3,398	3,635	3,396	3,456	-5%	2	2
Total	**26,457**	**25,686**	**23,768**	**23,602**	**25,715**	**23,937**	**24,382**	**-5%**		
Total excluding WPD	**19,531**	**18,760**	**16,841**	**17,321**	**18,788**	**17,011**	**17,455**	**-7%**		

* We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.

2.17. Tables 2.12 and 2.13 compare the annual average costs in DPCR5 to the slow-track submitted and allowed costs.

Table 2.12: Annual average DPCR5 and RIIO-ED1 costs - by DNO (2012-13 prices)

DNO	DPCR5 totex (based on 4yrs actual)	DPCR5 totex (based on 4yrs actual, 1y forecast)	Slow-track final determinations allowance post IQI*	Difference (RIIO-ED1 allowance minus DPCR5 5yrs)	
	£m	£m	£m	£m	%
ENWL	240	244	228	-15	-6%
NPgN	160	163	158	-5	-3%
NPgY	210	221	212	-10	-4%
WMID	270	275	259	-16	-6%
EMID	262	262	260	-1	0%
SWALES	124	125	135	10	8%
SWEST	179	182	212	29	16%
LPN	209	220	221	1	0%
SPN	226	228	215	-13	-6%
EPN	340	344	317	-27	-8%
SPD	194	198	190	-8	-4%
SPMW	227	239	208	-30	-13%
SSEH	123	125	140	15	12%
SSES	271	283	292	9	3%
Total	3,035	3,108	3,048	-61	-2%
Total excl WPD	**2,201**	**2,265**	**2,182**	-83	-4%

* Totex post IQI interpolations is based 75% on the Ofgem view and 25% on the DNO forecast.
** The costs exclude RPEs to allow a direct comparison of modelled costs prior to the application of RPE savings. We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.
*** Ofgem efficient view of totex in these tables is prior to interpolation. Our final view of DNO totex under the IQI mechanism is based on 75% of the Ofgem view and 25% of the DNO forecast.

2.18. While DNOs' actual expenditure towards the end of DPCR5 is anticipated to be in line with our allowances, over the whole period their actual expenditure is below our allowances. It is also significantly below DNOs' DPCR5 forecasts. The profile for our allowances for the RIIO-ED1 period brings the DNOs' allowances towards the end of RIIO-ED1 back in line with their average DPCR4 actual expenditure (in real terms). We view this as reasonable as in DPCR5 the DNOs had high levels of network investment to replace assets installed during the investment peak in the 1950s/60s.[5]

[5] Ofgem, Electricity Distribution Price Control Review: Methodology and Initial Results Paper, May 2009, page 5.

Table 2.13: Annual average DPCR5 and RIIO-ED1 costs - by DNO Group (2012-13 prices)

DNO	DPCR5 totex (based on 4yrs actual)	DPCR5 totex (based on 4yrs actual, 1y forecast)	Slow-track final determinations allowance post IQI	Difference (RIIO-ED1 allowance minus DPCR5 5yrs)	
	£m	£m	£m	£m	%
ENWL	240	244	228	-15	-6%
NPg	370	385	370	-15	-4%
WPD	834	843	866	22	3%
UKPN	776	793	754	-39	-5%
SPEN	421	436	398	-38	-9%
SSEPD	394	408	432	24	6%
Total	3,035	3,108	3,048	-61	-2%
Total excluding WPD	2,201	2,265	2,182	-83	-4%

Key results by DNO

2.19. We summarise below five of the high level results for each of the ten slow-track DNOs:

- the change from fast-track to slow-track forecast costs (summarised in Table 2.1)
- the findings from each of our three benchmarking models and our combined assessment after the application of the UQ (Tables 2.3)
- our view of RPE and smart grids adjustments (Tables 2.5)
- our final expenditure view of efficient expenditure after applying all adjustments (Tables 2.9), and
- the difference between DPCR5 spend and our view of efficient RIIO-ED1 expenditure (Tables 2.12).[6]

ENWL

2.20. ENWL cuts £24m from its fast-track submission to its slow-track submission at final determinations.[7]

2.21. It performs well in our comparative benchmarking models with our combined UQ benchmark 1% higher than ENWL's submitted forecast. It performs well on all three models, with strongest performance in both totex models.

2.22. As with other DNOs it has submitted high RPE forecasts. Our view of RPEs is £77m lower than ENWL's submitted costs. We also believe it could achieve an extra £8m smart grid savings.

[6] DPCR5 costs are based on the actual costs for the first four years of DPCR5 and the forecast costs for the final year.
[7] £24m was cut from fast-track to draft determinations but we showed this as £23m in draft determinations, since we wrongly included £1m of rail electrification.

2.23. The modelled totex allowance post IQI, taking these factors into account, is 3% below ENWL's forecast. ENWL is the frontier DNO of the ten slow-track DNOs and is at the frontier of the five DNO groups. It has moved up from 2^{nd} to 1^{st} in the DNOs rankings from draft determinations and it remains the frontier group.

2.24. ENWL's annual allowed expenditure for RIIO-ED1 post IQI interpolation is 6% lower than its annual average DPCR5 expenditure.

NPgN

2.25. Excluding rail electrification costs, NPgN increased its slow-track submission at final determinations by £4m from fast-track. This is made up of a £2m reduction from fast-track to draft determinations and a £6m increase after draft determinations.

2.26. In our comparative benchmarking our combined UQ benchmark is 6% lower than NPgN's submitted forecast for final determinations. It performs well on our top-down totex model but we have identified some potential inefficiency in our bottom-up totex model and particularly in our disaggregated model.

2.27. Our view of RPEs is £60m lower than NPgN submitted and we think it can make £21m further savings on smart grids.

2.28. The modelled totex allowance post IQI is 8% below NPgN's forecast. NPgN ranks 6^{th} of the ten slow-track DNOs at final determinations. At draft determinations it was 7^{th}.

2.29. NPgN's annual modelled expenditure post IQI interpolation for RIIO-ED1 is 3% lower than its annual average DPCR5 expenditure.

NPgY

2.30. Excluding rail electrification costs, NPgY reduced its slow-track submission at final determinations by £54.6m from fast-track – a £49m reduction from fast-track to draft determinations and a further £5m reduction post draft determinations.

2.31. In our comparative benchmarking our combined UQ benchmark is 4% lower than NPgY's submitted forecast. NPgY performs well on both our totex models but we have identified some potential inefficiency in our disaggregated modelling.

2.32. Our view of RPEs is £80m lower than NPgY's submitted and we think it can make £21m further savings from smart grids.

2.33. The modelled totex allowance post IQI is 6% below NPgY's forecast. NPgY ranks 4^{th} of the ten slow-track DNOs in our slow-track assessment. It also ranked 4^{th} at draft determinations.

2.34. NPgY's annual modelled expenditure for RIIO-ED1 post IQI interpolation is 4% lower than its annual average DPCR5 expenditure.

LPN

2.35. LPN increased its slow-track submission by £2m overall from fast-track. It reduced its fast-track submission by £7m at draft determinations but subsequently added £9m. This is largely due to costs of managing the risks of link box explosions. This is discussed in more detail in Chapter 4.[8]

2.36. In our comparative benchmarking our combined UQ benchmark is 9% lower than LPN's submitted forecast at slow-track draft determinations. Our modelled costs in all three models are lower than LPN's submitted costs, with performance worse in the disaggregated model.

2.37. Our view of RPEs is £73m lower than LPN's submitted and we think it can make further savings of £29m from smart grids.

2.38. The modelled totex allowance post IQI is 10% below LPN's forecast. LPN ranks 9th of the ten DNOs in our slow-track assessment at final determinations. Its overall rank did not change from draft determinations.

2.39. LPN's annual average expenditure for RIIO-ED1 post IQI interpolation is the same as its annual average DPCR5 expenditure for LPN.

SPN

2.40. SPN reduced its slow-track submission at final determinations by £26m from fast-track – it cut £39m from fast-track to draft determinations, but added £13m to its submission post draft determinations. This is largely explained by costs of managing the risks of link box explosions, changes to CNI categorisation and the correction of errors in the business plan data tables (BPDTs).[9]

2.41. Our combined UQ benchmark is 6% lower than SPN's submitted forecast. Our modelled costs are lower than SPN's submitted costs for both the bottom-up totex and disaggregated models. SPN performs well in the top-down totex model.

2.42. Our view of RPEs is £71m lower than SPN submitted and we think it can make £22m further savings from smart grids.

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[8] This increase in link boxes costs only covers the first two years of RIIO-ED1 excluded, with the remaining years dealt with under an uncertainty mechanism.
[9] Footnote 8 applies.

2.43. The modelled totex allowance post IQI is 8% below SPN's forecast. SPN ranks 7th of the ten DNOs in our slow-track final determinations assessment. Its overall rank at draft determinations was 5th.

2.44. SPN's annual modelled expenditure for RIIO-ED1 post IQI interpolation is 6% lower than the annual average DPCR5 expenditure.[10]

EPN

2.45. EPN reduced its slow-track submission by £86m from fast-track. It reduced its fast-track submission by £96m at draft determinations, but subsequently added £10m. This is largely explained by costs of managing the risks of link box explosions, changes to CNI categorisation and the correction of errors in the BPDTs.

2.46. In our comparative benchmarking our combined UQ benchmark is 6% lower than EPN's submitted forecast. Our modelled costs in all three models are lower than EPN's submitted costs, with performance worse in the top-down totex model.

2.47. Our view of RPEs is £106m lower than EPN submitted and we think it can make further savings of £53m from smart grids.

2.48. The modelled totex allowance post IQI is 9% below EPN's forecast. EPN ranks 8th of the ten DNOs in our slow-track final determinations assessment. Its overall rank at draft determinations was 6th.

2.49. EPN's annual modelled expenditure for RIIO-ED1 post IQI interpolation is 8% lower than the annual average DPCR5 expenditure.

SPD

2.50. SPD reduced its slow-track submission at final determinations by £177m from fast-track. It reduced its fast-track submission by £176m to draft determinations and subsequently by a further £1m.

2.51. Our combined UQ benchmark is 4% higher than SPD's submitted forecast. It performs well across all three models, with strongest performance in the two totex models.

2.52. Our view of RPEs is £64m lower than SPD submitted and we think it can save a further £55m from smart grids.

[10] Footnote 8 applies.

2.53. The modelled totex allowance post IQI is 3% below SPD's forecast. SPD ranks 2nd of all ten slow-track DNOs. It was frontier at draft determinations.

2.54. SPD's annual modelled expenditure for RIIO-ED1 post IQI interpolation is 4% lower than the annual average DPCR5 expenditure.

SPMW

2.55. SPMW cut £297m from its fast-track submission overall. It reduced its fast-track submission by £293.4m at draft determinations and subsequently cut a further £3.4m.

2.56. Unlike SPD, SPMW performs poorly in our comparative benchmarking. Our combined UQ benchmark is 11% lower than SPMW's submitted forecast. Our modelled costs in all three models are lower than SPMW's submitted costs, with the difference much greater for the two totex models.

2.57. We note the wide gap between the two SPEN DNOs: SPD and SPMW. We consider that there are three potential reasons for this: (i) SPEN has forecast a larger increase in expenditure in its SPMW network than in its SPD network relative to DPCR5; (ii) SPD forecasts are relatively low compared to DNOs of similar scale while SPMW's forecast is relatively higher; and (iii) the allocation of indirect costs within the groups also potentially distort the efficiency rankings.

2.58. Our view of RPEs is £83m lower than SPMW submitted and we think it can make an additional £60m savings from smart grids.

2.59. The modelled totex allowance post IQI is 13% below SPMW's forecast. Our assessment places SPMW as the least efficient of the ten slow-track DNOs. Its ranking has not changed from draft determinations.

2.60. SPMW's annual modelled expenditure for RIIO-ED1 post IQI interpolation is 13% lower than the annual average DPCR5 expenditure.

SSEH

2.61. SSEH reduced its expenditure by £20m from its fast-track submission to its slow-track submission at draft determinations. It made no change post draft determinations.

2.62. Our combined UQ benchmark is 5% lower than SSEH's submitted forecast. Our modelled costs in all three models are lower than SSEH's submitted costs, but our modelled view is closest to its submitted costs for the disaggregated model.

2.63. Our view of RPEs is £37m lower than SSEH's and we think it can make further savings of £14m from smart grids.

2.64. The modelled totex allowance post IQI is 7% below SSEH's forecast. SSEH ranks 5th of the ten DNOs in our slow-track final determinations assessment. It was ranked 8th at draft determinations.

2.65. SSEH's annual modelled expenditure for RIIO-ED1 post IQI interpolation is 12% higher than the annual average DPCR5 expenditure.

SSES

2.66. SSES reduced its expenditure by £65m from its fast-track submission to its slow-track submission. It made no changes after draft determinations.

2.67. Our combined UQ benchmark is less than 1% lower than SSEH's submitted forecast. It performs well in the two totex models, with our modelled costs slightly lower than its submitted costs in the disaggregated model.

2.68. Our view of RPEs is £76m lower than SSES submitted and we think it can save an additional £39m from smart grids.

2.69. The modelled totex allowance post IQI is 4% below SSES's forecast. SSES ranks 3rd of our ten slow-track final determinations DNOs. It also ranked 3rd in draft determinations assessment.

2.70. SSES's annual modelled expenditure for RIIO-ED1 post IQI interpolation is 3% higher than the annual average DPCR5 expenditure.

3. Summary of cost assessment

Chapter summary

An overview of our cost assessment models and how we combine the results.

Overview of our expenditure assessment methodology

3.1. As at fast-track and draft determinations, we use a toolkit approach to assess the DNOs' expenditures. Our work includes quantitative and qualitative assessment, reviewing DNO narrative and supporting evidence, including historical cost and performance data and company forecasts. We have done both comparative analysis and company-specific assessment.

3.2. We review qualitative evidence in our disaggregated analysis and where appropriate make adjustments to our quantitative benchmarking. These are largely positive qualitative adjustments, although some negative adjustments are made.

3.3. We have had many meetings with the DNOs to discuss the cost assessment approach following the submission of their revised plans in March and our publication of the draft determinations in July.

3.4. We refined our cost assessment data and models to correct for errors and inconsistencies and to account for additional evidence submitted by the DNOs. We refined our approach to regional wage adjustment, removed most ratchets from our disaggregated analysis and changed the modern equivalent asset value (MEAV) cost driver. We changed MEAV (across all the models) to ensure that the costs we are assessing and the associated cost drivers are on a like-for-like basis. That is, where we have normalised the costs associated with certain assets out of our analysis because they are atypical we have also removed them from MEAV.

3.5. In our supplementary question process some DNOs provided revised forecasts in a number of areas, including the costs of managing the risk of link box explosions by UKPN.

3.6. We describe the changes in the relevant chapters and appendices.

3.7. In the remainder of this chapter we summarise our approach to the three cost assessment models.

Cost assessment models

3.8. We carry out comparative analysis at a totex level using two different totex models and on a cost activity level basis using disaggregated activity-level modelling.

3.9. Our use of three models acknowledges that there is no definitive answer for assessing comparative efficiency and we expect the models to give different results. There are advantages and disadvantages to each approach. Totex models internalise operational expenditure (opex) and capital expenditure (capex) trade-offs and are relatively immune to cost categorisation issues. They give an aggregate view of efficiency. The bottom-up, activity-level analysis has activity drivers that can more closely match the costs being considered.

3.10. Chapter 5 provides more detail on the totex models and Chapters 6 to 10 on the disaggregated analysis.

3.11. We use either five years of DPCR5 data (2010-11 to 2014-15), eight year of RIIO-ED1 forecast data (2015-16 to 2022-23) or the full 13 years in all our models. It is important to note that DPCR5 data is a combination of actual and forecast data. The first three years of DPCR5 data are actual data, the fourth year (2013-14) is close to actual data (ie the best estimate of DNOs for 2013-14 expenditure at the time of their business plans submissions in March 2014) and the final year of DPCR5 is forecast data.

3.12. DNOs submitted actual data for 2013-14 on 31 July 2014 as part of annual reporting requirements. This data was reported under the DPCR5 Regulatory Instructions and Guidance (RIGs), while the data for the business plans was provided in the format of the RIIO-ED1 Business Plan Data Tables (BPDTs). The two sets of data are not directly comparable.

3.13. We asked the DNOs to submit the RIGs annual data in the BPDT format so we could compare the best estimates of actuals submitted in March with the actuals submitted in July.

3.14. The DNOs had limited time to re-cut the data and were unable to carry out rigorous data assurance. We ran sensitivity analysis to determine if replacing the March data with the July data would significantly affect the results. It did not. Further detail on this sensitivity is presented in Appendix 6. We have used the data as reported in March in our analysis rather than the July data.

Top-down totex model

3.15. In the top-down totex model we use regression analysis to determine efficient costs relative to a composite scale variable (CSV). The CSV is a combination of MEAV and customer numbers, with a weighting of 88% and 12%, respectively. We use statistical techniques to derive the weights to apply to each element (see Appendix 5 for more detail). The top-down totex model includes a time trend for costs.

3.16. We use 13 years of data (five years of DPCR5 and eight years of RIIO-ED1). We consider that use of both historical and forecast data better takes account of the scope for efficiency savings which are reflected in the DNO data and is in line with our RIIO approach of placing greater weight on forecast data. Using a longer time period also lessens the impact of different expenditure plans between DNOs (eg tree cutting cycles), and recognises trade-offs between different responses to similar issues (eg investment or innovation).

3.17. The use of 13 years of data for the totex models is consistent with our disaggregated model where we make extensive use of forecast data.

3.18. We have made a minor change to the top-down totex model to correct an error in the customer number data. For both totex models we exclude fewer costs from the totex benchmarking than at draft determinations, as we explain in Chapter 4. Chapter 3 provides detail on the composition of MEAV.

Bottom-up totex model

3.19. We also use a bottom-up totex model. This uses 13 years of data and excludes the same cost activities as the top-down totex model. It also includes a time trend. The key difference between the two models is the cost drivers used to estimate efficient costs. The bottom-up totex model aggregates drivers used in the disaggregated analysis into a single CSV. Appendix 5 provides more detail on the approach to calculating this CSV.

Disaggregated model

3.20. The disaggregated analysis incorporates a mixture of cost assessment techniques including regression analysis, ratio analysis, trend analysis and technical assessment. The approach is tailored to the activity being assessed. We describe the key components of the disaggregated modelling below.

3.21. For asset replacement we use a bespoke age-based model to assess two-thirds of the asset replacement category costs. This model takes account of the age of a DNO's assets. We completed a detailed qualitative assessment of the DNOs' cost and volumes justification with our expert engineering consultants, DNV GL. This involved cross-checking our model results against historical and forecast information, condition information contained in the secondary deliverables for asset health and criticality, scheme papers and other justification. Where appropriate we make qualitative adjustments to our modelled results to take this into account.

3.22. We ensured consistency between refurbishment and replacement, and scrutinised individual schemes and approaches in detail.

3.23. We conducted a detailed review of load-related expenditure looking at whether particular schemes are justified and assess the efficiency of unit costs. Our engineering consultants analysed a range of scheme papers and we adjusted our modelling to reflect their conclusions. Since draft determinations, we reviewed additional evidence on the scheme papers following discussions with DNOs.

3.24. For other areas of network investment, we adopt a bespoke approach considering the engineering evidence in conjunction with our engineering consultants, who provided detailed input where required and high level sense checking elsewhere.

3.25. For closely associated indirect (CAI) costs, we use a combination of regression analysis, ratio analysis, run rate analysis and qualitative review. Eight categories of CAI costs, which comprise about 70% of total CAI costs, were aggregated and assessed using regression analysis. The regression uses eight years of forecast data for RIIO-ED1.

3.26. The majority of business support costs (BSCs) are assessed at an aggregate level using ratio benchmarking based on 13 years of data for the DNO groups. We use MEAV as the cost driver. We do not apply a singleton adjustment for fixed costs. We assess IT and telecoms separately with a combination of ratio analysis and consultant's qualitative views.

3.27. For network operating costs (NOCs) we use a combination of regression analysis and ratio analysis. For fault costs we held DNOs to their historical fault rates rather than benchmarking fault rates across the DNOs.

Combining the results of our totex and activity level assessment

3.28. At draft determinations we considered that the DNOs had significantly improved the quality of their data in their slow-track submissions versus fast-track. We had greater confidence in the totex models at draft determinations and gave them greater weight. We applied a 25% weighting to each of the totex models and a 50% weighting to our disaggregated modelling.[11] This was consistent with our approach for RIIO-GD1.

3.29. Some DNOs disagreed with our change in weighting. Their counter-proposals tended to be biased to models which favoured them. We have not changed the weightings for final determinations.

3.30. We benchmark the efficient level of totex for each DNO using the UQ rather than the frontier to allow for other factors that may influence the DNOs' costs. The UQ level of efficiency (lower quartile level of costs) is the 25th percentile in the distribution of efficiency scores. We assess the UQ after we combined the results from the three models.

3.31. This method works well for areas of costs where there are differences in efficiency across companies and forecasts reveal information about comparative efficiency across

[11] At fast-track we applied 12.5% weightings to each of the totex models and 75% weighting to the disaggregated model.

the DNOs. It does not cater for instances where we consider all the DNOs to be inefficient. This is the case for the RPEs and smart grids assessments. We therefore applied the RPE and smart grids adjustments after the application of the UQ.

Smart grids and RPEs

3.32. Two elements of the DNOs' ex ante allowances are added after the UQ is applied; the adjustment for smart grids and other innovation benefits, and real price effects and ongoing efficiency.

3.33. We adjust DNOs' allowances to embed savings from smart grids and other innovation. We benchmark the savings forecast by the DNOs separately for the following areas:

- LV-EHV general reinforcement
- 132kV general reinforcement
- fault level reinforcement
- other cost areas.

3.34. For most reinforcement cost areas we benchmark the savings forecast as a proportion of expenditure at the UQ. In fault level reinforcement we benchmark at 75 % of the best performing DNO due to a lack of data. In other cost areas outside reinforcement we base our assessment on the best performing DNO across these areas in aggregate. We consider that there is no material double counting between the smart grids assessment and the general cost assessment. To mitigate any risk we have amended our methodology particularly in the areas of reinforcement, LV fault finding and smart meters.

3.35. The DNOs' ex ante allowances include the expected impact of real price effects (RPEs). We apply a consistent RPE assumption to all slow-track DNOs. This common assumption is derived in three stages:

1. We construct an input price trend relative to RPI for the inputs purchased by a typical DNO.
2. We weight these input price trends based on a fixed proportion of each input in each cost area.
3. We multiply this assumption by each DNO's efficient cost allowance to derive the monetary impact of the RPE assumption.

3.36. The monetary impact of RPEs is calculated for each of the models individually. A weighted average is added to the cost allowances following the application of the UQ.

3.37. We have not made an adjustment for ongoing efficiency as we consider all DNOs' assumptions to be efficient.

Summary of approach

3.38. Figure 3.1 is a high level summary of the cost assessment approach taken.

Figure 3.1: Slow-track approach

Submitted information	Review all data and documentation.
Cleansing and adjustments	Apply normalisations and regional cost adjustments to ensure benchmarking DNOs on a comparable basis. Exclude certain costs.
Run totex models	Run totex regression models based on 13 years' of data (2010-11 to 2022-23). Top-down totex model: high level driver Bottom-up totex model: activity level driver.
Run disagg. model	For non-regressed cost activities carried out quantitative, qualitative and technical assessment to determine efficient costs. For regressed activities run regression models. Sum the results.
Combine all 3 models	Combine the three models applying 25% weight to each totex model and 50% weight to disaggregated model.
Calculate UQ	Calculate modelled costs at the UQ level of performance for three models combined, measured as the ratio of total submitted costs to total modelled costs for each DNO.
Reverse adjustments	Add back an efficient view of normalisations/adjustments.
Apply UQ	Apply UQ to total costs of all 3 models to calculate modelled costs prior to IQI interpolation.
RPEs and smart grids	Add Ofgem's view of RPEs and smart grids to derive modelled costs.
Efficient costs	Post IQI interpolation: apply 75% of Ofgem view and 25% DNO view.

Changes from draft to final determinations

3.39. Table 3.1 provides a summary of the key changes made to our cost assessment from draft to final determinations. The subsequent chapters explain why we adopted each approach at final determinations.

3.40. We refined our approach largely as a result of the issues raised after draft determinations. In some instances we made wider changes to the approach than the issue raised as this prompted us to do a further review of our approach. For example, some DNOs raised specific issues with totex exclusions (ie to exclude ESQCR costs) and we not only looked at those but the approach to totex exclusions as a whole. Similarly for IT&T some DNOs raised issues with the specific parts of IT&T qualitative assessment. We asked the consultants to review the entire qualitative assessment.

Table 3.1: Key changes in approach from draft to final determinations

Area/activity	Draft determinations approach	Final determinations approach
Regional labour adjustments	Adjustment for three regions and no adjustment for BSCs. Calculated labour indices for the three regions of London, South East and rest of Great Britain using ASHE data. Took into account the additional labour costs associated with working in London and the South East and considered the proportion of work that is done in these areas and elsewhere. These adjustments affected all DNOs.	As draft determinations with two key changes. Removed the weighting on some Standard Occupational Classification (SOC) codes not consider relevant to the activity areas we are adjusting. Moved to a notional weighting approach based on the DNOs' average labour to gross expenditure ratio for each activity.
Company specific factors	Case by case review using engineering expertise.	No change. Reviewed cases and corrected errors in adjustments.
Indirect cost allocations	Apply DNO cost allocation.	No change.
Excluded costs from totex	Fifteen areas excluded from both totex models: transmission connection point (TCP) charges, critical national infrastructure (CNI), rising and lateral mains (RLM), improved resilience, smart meter call out cost, quality of service (QoS), new streetwork costs, flood mitigation, BT21C, losses and environmental, operational and non-op capex IT&T, ETR 132 tree cutting activity, wayleaves and third party connections.	Only excluded the first eight areas listed.
MEAV calculation	Calculated for each DNO by multiplying every asset on the DNO's asset register by our view of the unit cost of that asset. It excludes: rising and lateral mains (RLM), LV service associated with RLM, batteries at ground mounted HV substations, 3kV substations, 66kV substations, and 132kV substations, pilot wire overhead, pilot wire underground, cable tunnels (DNO owned), cable bridges (DNO owned), electrical energy storage.	As draft determinations but now excludes the volumes as well as the costs of the assets associated with the SPMW special case.

Totex models		
Top-down totex	Regression analysis using 13 years of data and a CSV of MEAV and customer numbers. Exclusions as noted above.	No change except fewer areas excluded.
Bottom-up totex	Regression analysis using 13 years of data and a cost driver comprised of the disaggregated activity level drivers into a single cost driver. Exclusions same as top-down model.	No change except fewer areas excluded.
Disaggregated models		
Ratchet mechanisms (lower of modelled or submitted costs).	This was applied to asset replacement, refurbishment, n-1 primary reinforcement, civil works, ESQCR, legal and safety, losses & environmental, ETR 132 tree-cutting and non-operational capex (property and STEPM).	Remove ratchets for all except asset replacement, refurbishment and primary reinforcement (n-1).
Network investment: load-related		
Primary network reinforcement (n-2)	Volumes: accepted. Unit costs: asset replacement unit costs (median unit cost analysis and expert review).	No change.
Primary network reinforcement (n-1)	Volumes: ratio of forecast capacity added, relative to the increase in demand above firm capacity was benchmarked at the industry average. Unit costs: adjusted by the average percentage adjustment of the difference between: - DNO and expert view unit cost - DNO and industry median unit cost of 1 MVA capacity increase and - median ratio of DNO forecast to historic unit costs of 1 MVA of capacity increase.	No change, but reviewed our modelled costs for some schemes and made a small volume qualitative adjustment for SPMW.
LCT reinforcement	Volumes: industry median eight-year RIIO-ED1 forecast of network interventions per MW of LCTs connected. Unit costs: industry median unit costs using eight year RIIO-ED1 data. Excluded unbundling of shared service cables from our modelling and subjected them to a separate technical review.	No change.
Secondary reinforcement	Volumes: industry median eight-year RIIO-ED1 forecast of network interventions per MW of LCTs connected. Unit costs: industry median unit costs using eight year RIIO-ED1 data. Excluded unbundling of shared service cables from our modelling and subjected them to a separate technical review.	No change.
Fault level reinforcement	Volumes accepted. Unit costs: median DNO forecast and applied an adjustment factor based on the network characteristics.	No change except a qualitative adjustment for NPgN.
Transmission connection points	Qualitative review.	No change.

Connections	Volumes for RIIO-ED1 were generally accepted. Unit costs: average of the industry's RIIO-ED1 median and the company's own or industry DPCR5 median unit cost. Qualitative adjustments were made where appropriate.	No change.
Network investment: core		
Asset replacement	Volumes: bespoke age-based survivor model, run rate analysis and qualitative assessment. Unit costs: median unit cost analysis and expert review.	No change but reviewed some asset volume and unit cost adjustments.
Refurbishment	Volumes: un rate analysis and qualitative assessment. Unit costs: median unit cost analysis and technical review.	No change but reviewed some asset volume and unit cost adjustments.
Civil works	Ratchet: lower of modelled or submitted costs. Volumes: for each detailed cost area, median run rate as percentage of the asset base. Unit costs: industry median using eight years of RIIO-ED1 data.	No change, except removal of ratchet.
Network investment: non-core		
Operational IT&T	25% weight to quantitative assessment and 75% to qualitative expert review. Quantitative assessment: assessed with non-op capex. Industry median unit costs applied, calculated using MEAV as cost driver and 13 years of data.	No change but revisited qualitative expert review.
Diversions	Volumes: accepted. Unit costs: median using eight years of RIIO-ED1 data.	No change.
Diversions: rail electrification	No ex ante allowances set.	No change.
ESQCR	Ratchet: lower of modelled or submitted costs. Volumes: accepted. Unit costs: median at each voltage using 13 years of data.	Ratchet removed and unit cost calculation excludes completed scope of works.
Legal & safety	Ratchet: lower of modelled or submitted costs. Volumes: accepted. Unit costs: median at each voltage using 13 years of data.	Two changes: removal of the ratchet and asbestos management excluded from the benchmarking.
QoS	No ex ante allowances set.	No change but QoS considered in our review on central London reinforcement and worst served customer analysis.
Flood resilience	Risk-based approach. Risk point delta calculated for each substation before and after intervention. Unit cost of each risk point reduced/maintained the lower of the DNO's own and the industry LQ. Unit cost applied that to the delta.	No change, except correction of error in calculation.

BT21C	Volumes: accepted. Unit costs: industry median using 13 years of data. Qualitative adjustment made for SPMW special case.	No change to base model. No qualitative adjustment for SPMW.
Losses and environment	Lower of modelled or submitted costs. Volumes: accepted. Unit costs: were bespoke to each category, but generally median unit costs using 13 years of data.	Two changes: removal of the ratchet and only using median cost where there are sufficient data points.
HILP	No costs submitted.	No change.
CNI	Costs accepted as submitted.	No changes to approach but changes to CNI sites from draft determinations.
Black start	Volumes: no greater than unprotected primary substations. Unit costs: industry median using 8 years of forecast data.	No change.
Rising and lateral mains (RLM)	Volumes: accepted. Unit costs: based on customer numbers as cost driver using all 13 years of data.	No change.
Improved resilience	Technical review.	No change to approach but additional evidence results in higher modelled costs.
Network operating costs		
Troublecall	Bespoke ratio benchmarking - bespoke for each voltage level and fault category.	Change made to submarine cable unit cost assessment; awarding DNOs their own unit cost.
Occurrences not incentivised (ONIs)	Bespoke ratio benchmarking - bespoke for each voltage level and fault category.	Small change to mirror the volume assessment for troublecall. Where there are large variations in unit costs for certain categories, further qualitative adjustments are made.
Severe weather – 1-in-20	Unit-cost based assessment only. Minimum of the unit costs from the RIIO-ED1 forecast and the unit costs of the DPCR5 period rolled forward.	Changed. Estimate an industry wide view of required expenditure. Based on 50% of DPCR5 UQ per annum cost of SW 1-20 events multiplied by the probability of a SW 1-20 event occurring, plus 50% of DNOs’ forecast expenditure. Expenditure allocated based on the overhead line (OHL) MEAV.
Inspections and maintenance (I&M)	Volumes: based on MEAV (with a different MEAV used for LPN to reflect its lack of overhead lines). Unit costs: industry median using 13 years of data.	No change.

Tree cutting	43-8 - regression using spans cut and inspected as cost driver and 8 years of RIIO-ED1 data. ETR 132 – volumes: accepted. Unit costs: lower of modelled (industry median using 8 years of data) or submitted. NPg excluded due to different approach (qualitative assessment)	43-8: No change. ETR 132: only change is removal of ratchet for unit cost assessment.
NOCs other	Substation electricity: industry median unit cost using eight years of RIIO-ED1 data to each substation. Dismantlement: industry median percentage annual increase in costs between DPCR5 to RIIO-ED1 to each DNO's DPCR5 costs. Remote location generation fuel costs and remote location generation operation and maintenance costs: DPCR5 actual (4 years) annual costs applied to the eight years of RIIO-ED1.	No change.
Ex-ante smart meter call out costs	Volumes: 2% call out rate. Unit costs: industry LQ.	No change
Improved resilience	Technical review.	No change to approach but additional evidence results in higher modelled costs.
Indirects		
CAIs: network design and engineering, project management, system mapping, EMCS, stores, network policy, control centre, call centre	Eight activities aggregated and regressed using 8 years of forecast data and MEAV and asset additions as the explanatory variable. Qualitative adjustment to UKPN allowances based on scale.	Regressed areas: no change
CAIs: wayleaves	Unit costs: industry median costs calculated using 13 years of data and total network length as cost driver.	Total network length replaced by number of supports as cost driver.
CAIs: vehicles and transport	Assessed together with non-operational capex vehicles. Unit costs: industry median, calculated using 13 years of data and MEAV as cost driver.	No change.
CAIs: operational training and workforce renewal	Operational training: applied industry median unit costs based on DNO submitted employee numbers. WFR: applied industry median unit costs based on DNO submitted leaver numbers.	A minor change to normalise for differences in retirement age.

Streetworks	Traditional streeworks costs embedded in relevant activity. Permits: volume and unit cost the lower of DNO own DPCR5 or RIIO-ED1 annual average. Permit condition costs: disallowed. Lane rentals: volumes were the lower of DNO own DPCR5 or RIIO-ED1 annual average. Unit costs based on lower of LPN DPCR5 or RIIO-ED1 annual average.	No change except permit conditions subject to a qualitative assessment following submission of further evidence.
BSCs: finance & regulation, HR & non-operational training, property management and CEO & group functions	Unit costs: industry median, calculated using 13 years of data and MEAV as cost driver.	No change.
BSC: IT&T	50% weight to quantitative assessment and 50% to qualitative expert review. Quantitative assessment: industry median unit costs applied, calculated using MEAV as cost driver and 13 years of data. Analysis at DNO group level.	No change.
Non-operational capex: IT&T	25% weight to quantitative assessment and 75% to qualitative expert review. Quantitative assessment: assessed with operational IT&T. Industry median unit costs applied, calculated using MEAV as cost driver and 13 years of data.	No change but revisit of qualitative expert review.
Non-operational capex: vehicles and transport	As per CAI vehicles and transport.	As per CAI vehicles and transport.
Non-operational capex: property	Ratchet: lower of DNO's own or industry annual average RIIO-ED1 cost.	Ratchet removed. Unit cost analysis applying industry median, calculated using 13 years of data and MEAV as cost driver.
Non-operational capex: small tools, equipment, plant and machinery	Lower of modelled or submitted. Unit costs: industry median, calculated using 13 years of data and MEAV as cost driver.	Fully assessed by a qualitative review.
Other		
RPEs	Common assumption for all DNOs using an average weighting of a selection of input price indices. Used a base year of 2012-13 from which to roll forward RPE growth and used actual data for 2013-14. We made an adjustment for a step-change in RPI in 2010.	As draft determinations but base year set at 2013-14 and use actual data to date for 2014-15. Corrected minor errors, changed wage growth forecast and updated assumptions for latest data.

Smart grids and ongoing efficiency	Used the DNOs' submissions, the Transform model and DECC's smart metering impact assessment to determine the level of savings DNOs should achieve. We assessed claims of smart savings made by the DNOs and disallowed a number of these. We allocated the savings between DNOs as a proportion of totex.	No longer use the Transform model or DECC's smart metering impact assessment to directly inform any of the adjustments. Now only benchmark the DNOs' submissions to determine the savings that should be achieved. Reviewed additional information and accepted some extra smart savings claimed by DNOs. Savings are allocated in proportion to expenditure in each relevant cost area.
Combination of models	25% weighting to each totex model and 50% weighting to the disaggregated model.	No change.
Upper quartile	Applied UQ to the combined total costs of all three models before application of RPEs and smart grid savings.	No change.

3.41. Further detail on the removal of some ratchets and the changes to MEAV is provided below.

MEAV

3.42. MEAV reflects the scale and composition of a DNO's network. It is a proxy for the cost of replacing every asset that is currently on a DNO's network. It is a key driver of costs.

3.43. MEAV is calculated for each DNO by multiplying every operational asset on the DNO's asset register by our view of the unit cost of that asset. The MEAV calculation used at draft determinations excluded the following assets:

- rising and lateral mains (RLM)
- LV service associated with RLM
- batteries at ground mounted HV substations, 33kV substations, 66kV substations, and 132kV substations
- pilot wire overhead
- pilot wire underground
- cable tunnels (DNO owned)
- cable bridges (DNO owned)
- electrical energy storage.

3.44. These exclusions ensure consistency across the DNOs in their MEAV calculations. We continue to exclude these assets for final determinations.

3.45. In response to an issue raised by one DNO we have removed asset volumes that relate to SPMW's special case (its interconnected network) from the MEAV calculation. This is to ensure that we do not bias the cost assessment by treating the expenditure being assessed and the cost drivers on an inconsistent basis. As discussed in Chapter 4, SPMW made the case that we should remove the additional costs it incurs for operating an interconnected network from its submitted costs prior to benchmarking. It is appropriate to adjust SPMW's MEAV by also removing asset volumes associated and identified through its special case. MEAV is used as a cost driver in our modelling. If we remove the costs of assets from submitted costs (the numerator) for consistency we should also remove the equivalent volumes of those assets from the MEAV (denominator). For SPMW this involves the costs and volumes for 6.6/11kV GM transformers, 6.6/11kV ground mounted primary circuit breakers, 6.6/11kV X-type RMU and 33kV circuit breakers. While we are making company specific adjustments for LPN and SSEH as these are not for specific assets, no equivalent adjustment to MEAV is needed.

Ratchets

3.46. Ratchets constrain our modelled costs to the lower of our view and the company forecasts. At draft determinations we applied ratchets to the following disaggregated areas:

- asset replacement
- refurbishment
- n-1 primary reinforcement
- civil works
- ESQCR
- legal and safety
- losses and environmental
- ETR 132 tree-cutting
- non-operational capex - property
- non-operational capex - small tools, equipment, plant and machinery (STEPM).

3.47. One DNO noted that the application of disadvantages those DNOs who are the most efficient in a particular activity. We have removed ratchets for most of the cost activities for final determinations.

3.48. For asset replacement and refurbishment volumes, we do not consider it appropriate to base our volume allowance on an estimate higher than the DNOs' submitted volumes. DNOs are likely to have built in some uncertainty into their asset forecasts (eg. through Condition Based Risk Management modelling and Health and Criticality Indices) and we have capped the network asset risk secondary deliverables at the level submitted by the DNOs. Therefore we do not consider it appropriate to base our volume allowance on an estimate higher than the DNO's submitted volumes. This is a pragmatic approach given the differences in asset lives estimated under different asset profile scenarios, the DNOs' ability to trade-off between refurbishment and replacement and the relationship with the secondary deliverables.

For reinforcement there was a ratchet in the high level ratio benchmarking for primary reinforcement. This modelling acts as a trigger for a qualitative scheme review which we have carried out so we consider that it is appropriate to retain this.

4. Normalisations, exclusions and adjustments

Chapter summary

A description of the normalisations, exclusions and adjustments we make to our modelling, a discussion of two company specific issues in more detail – link boxes and London strategic investment.

Normalisations, exclusions and adjustments

4.1. We consider whether DNO submitted data require adjustments prior to carrying out our comparative benchmarking. This is to ensure that the comparisons are on a like-for-like basis. Where we decide adjustments are appropriate, we adjust the DNO submitted costs before our totex and disaggregated assessments. These adjustments fall into four broad categories:

1. **Regional labour costs.** These adjustments are made as operating in certain parts of the country attracts significantly higher labour costs. These apply to the two totex models and the disaggregated model in the same way.
2. **Company specific factors**. These are additional costs associated with operating a particular DNO network. The size of the adjustments differs in the disaggregated model compared to the two totex models. For some activities the disaggregated analysis already factors in the special case and to apply these adjustments again would be a double count. For example, if the special case is based on the need to do more volumes of work and our disaggregated model allows all the submitted volumes, we would not make a further company specific adjustment.
3. **Exclusions from totex models.** These are costs that are inappropriate for comparative benchmarking because they are not adequately explained by cost drivers that are being used in the totex models or because there is a substantial change in the nature of the activity between DPCR5 and RIIO-ED1. These exclusions only apply to the totex models. This does not apply to the disaggregated analysis. At the disaggregated level each cost activity is assessed by a bespoke model which uses the most intuitive cost driver and accounts for any changes in historical and/or forecast costs.
4. **Other adjustments.** Three other adjustments we make are to remove costs outside the price control, to remove non-controllable costs and to account for indirect cost allocation. These apply to the two totex models and the disaggregated model in the same way.

4.2. Once we estimate the modelled costs for each activity and for totex, we reverse the regional labour adjustments and company specific adjustments and add back an efficient view of those cost items excluded from our benchmarking analysis.

Decision and results

4.3. The table below details the normalisations made to the totex models in final determinations.

Table 4.1: Totex normalisations and exclusions (£m 2012-13 prices)

DNO	Regional labour cost adjustments	Company specific factors	Costs excluded from the totex regression	Total adjustments over RIIO-ED1
	£m	£m	£m	£m
ENWL	25	0	-33	-9
NPgN	19	0	-24	-5
NPgY	25	0	-23	2
WMID	24	0	-11	13
EMID	23	0	-11	12
SWALES	13	0	-5	9
SWEST	21	0	-6	15
LPN	-163	-117	-85	-365
SPN	-67	0	-63	-131
EPN	-32	0	-55	-86
SPD	21	0	-97	-76
SPMW	28	-113	-47	-133
SSEH	15	-32	-59	-76
SSES	-58	0	-26	-84

4.4. The details of the disaggregated normalisations are provided in Table 4.2.

Table 4.2: Disaggregated model normalisations factors (£m 2012-13 prices)

DNO	Regional labour cost adjustments	Company specific factors*	Total adjustments over RIIO-ED1
	£m	£m	£m
ENWL	25	0	25
NPgN	19	0	19
NPgY	25	0	25
WMID	24	0	24
EMID	23	0	23
SWALES	13	0	13
SWEST	21	0	21
LPN	-163	-117	-280
SPN	-67	0	-67
EPN	-32	0	-32
SPD	21	0	21
SPMW	28	-13	14
SSEH	15	-32	-17
SSES	-58	0	-58

*This is a combination of pre-model normalisations and qualitative adjustments.

4.5. The difference between the normalisations from draft determinations to final determinations are presented in the relevant sub-sections below.

Regional labour cost adjustments

Decision and results

4.6. We continue to make a regional labour adjustment for three regions; London, South East and rest of Great Britain. We do not have a regional labour adjustment for BSCs.

4.7. We made two key changes from the normalisations at draft determinations. First we removed the weighting on some Standard Occupational Classification (SOC) codes which we do not consider relevant to the activity areas we are adjusting. We rescaled the remaining weights to sum to one. Second, we used notional weightings when applying the regional labour adjustment to individual activity areas. We based the notional weighting on the DNO average labour to gross expenditure ratio for each activity. This approach is consistent with our approach for RPEs.

4.8. The overall impact of our changes is relatively small, with the largest impact to LPN.

4.9. The difference between the regional labour normalisations at draft determinations and final determinations is presented in Table 4.3.

Table 4.3: Regional labour adjustments - difference between draft determinations and final determinations (£m 2012-13 prices)

DNO	Regional labour adjustment		Difference (fd minus dd)
	RIIO-ED1 draft determinations (£m)	RIIO-ED1 final determinations (£m)	
ENWL	28	25	-3
NPgN	26	19	-7
NPgY	33	25	-8
WMID	24	24	1
EMID	23	23	0
SWALES	13	13	1
SWEST	20	21	2
LPN	-191	-163	28
SPN	-79	-67	12
EPN	-37	-32	5
SPD	25	21	-4
SPMW	31	28	-4
SSEH	16	15	-1
SSES	-59	-58	1

Draft determinations

4.10. In draft determinations we applied a high hurdle for regional labour adjustments compared to previous network price controls. DNOs were required to provide appropriate evidence of cost differentials as part of their well justified business plans and explain what steps they were taking to mitigate these costs differences.

4.11. We considered the evidence presented by the DNOs and our own internal analysis on regional labour cost adjustments. We decided that it was reasonable to make some regional labour adjustments prior to carrying out our cost benchmarking.

4.12. The Office of National Statistics (ONS) Annual Survey of Hourly Earnings (ASHE) data supports evidence that labour cost differentials exist between London, the South East and elsewhere in Great Britain. Using the ONS ASHE information we calculated labour indices for the three regions of London, South East and rest of Great Britain. In addition, we took into account the additional labour costs associated with working in London and the South East and considered the proportion of work that is done in these areas and elsewhere. These adjustments affected all DNOs as it puts all labour costs on a consistent basis.

Responses

4.13. One DNO felt that rather than applying an adjustment for London and the South East only, different wage indices should be developed for each area of the country. The DNO group argued that the ONS ASHE data supported further regional wage adjustments and it supplied a consultant's report to support this.

4.14. Two DNOs thought that the adjustment overstated the impact of higher labour costs in London and the South East. One stated that differences between the weightings for different types of employee were not credible. The DNO group presented evidence that it considered indicated that compositional issues in the ONS occupations data set meant that like-for-like comparisons were not possible across regions. It proposed the use of a 10% top-down adjustment for London and no adjustment for the South East. It also felt that the weights on the amount of work carried out locally appeared to be arbitrary.

4.15. One DNO agreed with our methodology and stated that the methodology used at draft determinations had been established through a robust public consultation and was applied at RIIO-GD1 final determinations. It stated that it believed that there was no basis for Ofgem to change its approach from draft determinations.

Reasons for our decision

4.16. We do not consider that there is sufficient and compelling new evidence to support applying regional wage differentials for each region of GB given the mobility in the labour market. We maintain our adjustment for three regions. We do not make regional labour adjustments for business support costs in line with our view that these can be procured on a national basis.

4.17. We do not consider that the compositional issues evidence presented by one DNO demonstrates that the ONS data does not reflect DNOs' regional wages.[12] The use of

[12] The evidence presented suggested that there is a bias in ONS data whereby the data on salaries for London

ONS data is in line with our previous price controls and with the Competition Commission's final determinations for Northern Ireland Electricity Ltd price control and Ofwat's PR14.

4.18. Following further review, we removed the weighting on some SOC codes which we do not consider relevant to the activity areas we are adjusting. We consider the updated approach better reflects the SOC codes involved in the work we are adjusting for.

4.19. In addition we have used a notional weighting approach when applying the regional labour adjustment to individual activity areas. We consider this change is appropriate after identifying significant variation in labour as a proportion of expenditure across the DNOs. Notional weights ensure we do not reward a potentially inefficient company. The change also aligns our regional labour adjustment with our approach of using notional weights for RPEs.

Company-specific factors

4.20. This section provides a high level summary of the company specific cases submitted and our response to them. More detail is provided in Appendix 9.

4.21. We exclude company-specific costs from our totex modelling.[13] For our disaggregated models we exclude costs from the models unless:

- we make a qualitative adjustment at the disaggregated level to account for the special factor, or
- the company specific factor is not already factored into our base model. For example, if the special case is based on the need to do more volumes of work and our base model allows all the submitted volumes, there is no need to make a further adjustment.

Decision and results

4.22. We continue to make company-specific adjustments for three DNOs – SSEH, LPN and SPMW. The values of those adjustments are different to draft determinations (see Table 4.6) for LPN and SPMW. There are no changes for SSEH.[14] This follows a review of the issues raised at draft determinations.

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is biased towards higher paying occupations.
[13] We exclude our view of company specific costs and not those submitted by the relevant DNO.
[14] For SSEH there is uncertainty around the costs of subsea cables, specifically whether there will be a requirement to bury cables (a cost SSEH did not account for at draft determinations). We have not included any expenditure for this in the ex ante allowances. Any increase in these costs is covered via an uncertainty

4.23. We reviewed additional evidence from UKPN on its LPN London network strategy together with our engineering consultants. We accept most of the costs for a 24/7 operational presence and automation and unit protection. We now disallow the small amount we allowed at draft determinations for link boxes inspection costs. This is accounted for in other cost activities, as we explain further in paragraph 4.65. We no longer normalise streetwork costs (permits and lane rentals) as these costs are excluded from our main modelling and benchmarked separately.

4.24. SPMW provided additional information on pilot wires, and as a result we normalise our modelling for all of these costs. However, in the disaggregated modelling we no longer make a normalisation of £22.1m for reinforcement costs and a qualitative adjustment of £15m for BT21C.[15] SPMW suggests that due to its interconnected network its volumes for both reinforcement and for BT21C will be higher. We agree with this, but as our disaggregated analysis in both cases accepts the volumes forecast by SPMW, the special factor is already accounted for. We continue to make adjustments for these costs in the totex modelling.

4.25. A positive qualitative adjustment was made to SPMW's modelled costs to account for greater volumes of BT21C circuits. The SPMW special case for BT21C was based on the fact that the interconnected network will require more circuits to be replaced than for traditional radial networks. We agree with this, but as our disaggregated model accepts the volumes forecast by DNOs, the special factor is accounted for in our base model. Therefore, we do not need to make any further volume based qualitative adjustment.

4.26. We maintain our view not to make a fixed cost adjustment for ENWL to account for it not being part of a company group.

4.27. NPg submitted cases to make company-specific adjustments for NPgN and NPgY after the publication of draft determinations. We do not accept that they have provided sufficient evidence to support an adjustment and have not made any change for this.

4.28. Table 4.4 details the differences between the company specific adjustments at draft and final determinations. Further detail of our decision is provided in a report from our engineering consultants, DNV GL, in Appendix 9.

mechanism.

[15] SPEN noted that we make a qualitative adjustment in the supporting file of £15m despite DNV GL, our engineering consultants, suggesting this should be £18m. We no longer make any qualitative adjustment in the disaggregated model as the SPMW special case is accounted for in our disaggregated analysis as we allow all the volumes.

Table 4.4: Company specific adjustments for modelling - difference between draft determinations and final determinations

DNO	Totex			Disaggregated model		
	Draft determinations (£m)	Final determinations (£m)	Difference (fd minus dd)	Draft determinations (£m)	Final determinations (£m)	Difference (fd minus dd)
LPN	-90	-117	-27	-90	-117	-27
SPMW	-109	-113	-4	-52	-13	39
SSEH	-32	-32	-0	-32	-32	-0

Draft determinations

4.29. Four DNO groups proposed company-specific factors in their revised business plans. We explain what each DNO proposed, and our draft determinations below.

SSEPD

4.30. SSEPD provided evidence of additional costs associated with SSEH working in the Highlands and Islands of Scotland. We considered that the submission was generally sound and included 83% of its proposed adjustments in our two totex models and in our disaggregated model.

4.31. We concluded that SSEH's case for the higher costs for fixed diesel generation and subsea cable were adequately covered in our assessment of NOCs other and asset replacement analysis.

UKPN

4.32. UKPN included costs for its LPN network associated with working in London in addition to the regional labour costs noted above. These costs were divided into a number of distinct areas:

- transport and travel – additional costs associated with London congestion charging, the application of parking fines in Central London and increased costs associated with servicing vehicles in London. It also indicated there are additional costs associated with delivery of large items of plant in London.
- excavation – higher costs associated with excavations in the London area.
- security – additional costs associated with preparation of major events and the rescheduling of planned work as a result of these.
- property –additional insurance required for its properties in the London area.
- resourcing and contracting – additional costs of working in the London area including different labour rates, transport, travel costs and standby charges.

4.33. We accepted 41% of UKPN's claims for LPN.[16] The information provided, in particular in relation to its network strategy, did not provide sufficient justification to award the full adjustments.

SPEN

4.34. SPEN indicated that there are additional costs associated with operating and maintaining the interconnected network in its SPMW licence area. It noted that around 55% of the SPMW network is designed and run as an X-Type network, solidly interconnected at 33kV, 11kV and LV, rather than the more conventional Y-Type network. It noted that SPMW has smaller transformers than the industry standard and that standard cable sizes are used throughout.

4.35. We accepted 85% of SPEN's company specific claims for the SPMW network (after rejecting it in full at fast-track due to lack of appropriate justification). SPEN calculated the value of SPMW's operating costs through two methods: a bottom-up totex modelling approach (based on an evaluation of development stages of both interconnected and radial networks), and a top-down theoretical modelling approach. The case proposed detailed adjustments for the related cost areas of our assessment.

ENWL

4.36. ENWL is the only DNO operating a single licence. It proposed we make an adjustment for fixed costs associated with running a single network. It argued that single licensees are unable to obtain economies of scale and as such fixed costs may be higher than those for groups with multiple licensees.

4.37. We concluded that rather than applying just to ENWL, it is an issue of scale that applies to all DNOs to varying degrees. If we applied a fixed cost scalar to each of the DNO allowances we would need to change it if a DNO was subsequently purchased by, or divested from, a DNO group. We did not think that this was appropriate.

Responses

4.38. Five DNO groups responded to our assessment of company specific factors.

4.39. SPEN welcomed our additional recognition of its SPMW special case. However, it did not agree with our detailed efficiency assessment and said that it had identified unintended reductions resulting from the approach taken to combining the cost

[16] This included streetworks and excluded labour costs. Excluding streetworks we accepted 35%.

assessment models. It also pointed out an error in our analysis related to BT21CN.[17] Other DNOs believed we made to a high an adjustment for SPMW.

4.40. UKPN disagreed with the disallowed costs related to its London network strategy.

4.41. ENWL expressed its disappointment that we had made no fixed cost adjustments.

4.42. NPg thought we had not adhered to our own policy of setting a high bar for making company specific adjustments. It argued that it was inconsistent to include asset design differences as company specific factors (and excluded from the benchmarking models) and make qualitative adjustments after the base model results. It did not support normalisations or exclusions adjustments to the totex model and suggested these would be better dealt with at the disaggregated level where unit costs and volumes could be proposed and justified. Overall it did not support network design as a company specific factor, but argued that as we had considered this for SPMW we should have also considered the uniqueness of its own network of 20kV and 66kV assets.

Reasons for our decision

4.43. As with our regional labour adjustment, we continue to apply a high hurdle for company-specific factors. Companies are required to provide appropriate evidence of cost differentials as part of their well justified business plans and explain what steps they are taking to mitigate these costs differences.

4.44. We use regional factors to adjust for unique characteristics of DNO networks. In our disaggregated analysis, if our benchmarking shows the submitted costs or volumes to be efficient no additional adjustments are made. This explains the difference for SPMW regional factors between totex and disaggregated benchmarking.

4.45. SPMW provided justification for its regional case and showed that the annual proposed costs remained roughly the same between DPCR5 and RIIO-ED1. We found the majority of SPMW's reasonable case to be credible and have therefore allowed 88.5% of its proposed adjustment.

4.46. We had a series of discussions with UKPN on its London strategy. We visited the Short Gardens 24/7 operational centre, where UKPN explained its future plans and provided additional justification on the proposed investments. In addition we reviewed the information on the London strategy for all the related areas; regional normalisations, load reinforcements schemes, and high value projects. We accept the needs case for Shorts Gardens and London strategy investment schemes, but have made some efficiency adjustments to the costs of delivering the work. This is explained in detail in

[17] SPEN noted that we make a qualitative adjustment in the supporting file of £15m despite DNV GL, our engineering consultants, suggesting this should be £18m. As noted in paragraph 4.24 we no longer make any qualitative adjustment in the disaggregated model as the SPMW special case is accounted for in our disaggregated analysis as we allow all the volumes.

Appendix 9 and in the n-1 reinforcement section Chapter 6, respectively. We accept a significant proportion of LPN's company specific factor case but there were elements that were not adequately justified.

4.47. We maintain our position not to make a fixed cost adjustment for ENWL for the reasons set out at draft determinations.

Costs excluded from totex

Decision and results

4.48. There are a small number of areas where we consider it is appropriate to exclude costs from the two totex models. This is where costs are not explained by the cost drivers that are being used or where there is a substantial change in the nature of costs between the historical period we are using to estimate the cost models and RIIO-ED1. We exclude the costs before running our totex model and then add back in our efficient view (as calculated by the disaggregated analysis) to determine our efficient view of totex.

4.49. We have reduced the number of costs we exclude from our totex modelling. We have excluded the costs of the following seven activities:

1. transmission connection point (TCP) charges
2. critical national infrastructure (CNI)
3. rising and lateral mains (RLM)
4. improved resilience
5. quality of service (QoS)
6. smart meter roll out (including smart meter call out costs)
7. new streetwork costs.

4.50. The difference between the value of the excluded costs at draft determinations and final determinations is presented in Table 4.5.

Table 4.5: Totex exclusions - difference between draft determinations and final determinations

DNO	RIIO-ED1 draft determinations (£m)	RIIO-ED1 final determinations (£m)	Difference (fd minus dd)
ENWL	-162	-33	129
NPgN	-134	-24	110
NPgY	-158	-23	135
WMID	-149	-11	137
EMID	-147	-11	136
SWALES	-97	-5	93
SWEST	-119	-6	113
LPN	-187	-85	102
SPN	-151	-63	88
EPN	-250	-55	195
SPD	-211	-97	114
SPMW	-202	-47	155
SSEH	-197	-59	138
SSES	-168	-26	141

Draft determinations

4.51. At draft determinations we excluded the eight activities above plus the following seven activities:

1. flood mitigation
2. BT21C
3. losses and environmental
4. operational and non-op capex IT&T
5. ETR 132 tree cutting activity
6. wayleaves
7. third party connections.

Responses

4.52. Two DNOs broadly agreed with our approach of excluding costs that are only incurred by some DNOs. One suggested that ESQCR costs should be excluded from the totex assessment because the changes to health and safety legislation affect some networks to a greater degree than others.

4.53. Another DNO was concerned with our test and how consistently we applied it in our decision to exclude costs. It suggested that we reset the test. It argued that we did not distinguish between costs being incurred by a small number of DNOs and costs incurred where DNOs have different approaches to delivery of the output (for example DNOs have different levels of BT21C costs depending on the delivery solution). It argued that only the former costs should be excluded.

Reasons for our decision

4.54. We reviewed the reasons for excluding each activity and have concluded that the cost drivers we are using are sufficient to explain these costs. The 13 year period covered in the model ensures that timing issues and atypical costs are unlikely to distort the modelling. Almost all DNOs report some atypical expenditure which is likely to even out across a 13-year period. The magnitude of the exclusions was also very high at draft determinations and we were concerned that this was in part due to DNOs' allocation approaches. This may have distorted the results of the modelling.

4.55. We do not believe that it is appropriate to exclude Electricity Safety, Quality and Continuity Regulations (ESQCR) costs. We believe the scale of the network will drive the ESQCR costs of a DNO and we consider that the use of the 13-year time period takes account of the variation in spend over time. As such, MEAV and customer numbers are sufficient cost drivers. These costs are also incurred over both DPCR5 and RIIO-ED1 and our modelling uses data from both periods.

4.56. Table 4.6 set out the reasons for the changes.

Table 4.6: Costs excluded from totex modelling

Activity Area	Rationale for exclusion at draft determinations	Decision at final determinations and rationale
TCP charges	There is a significant change in the treatment and level of these costs between DPCR5 and RIIO-ED1.	No change.
CNI	Not explained by cost driver. The classification of sites as CNI is driven by the government and is outside DNOs' control.	No change.
RLMs	Not adequately explained by cost driver. This only affects a small number of DNOs.	No change.
Smart meter call out costs	Substantial change in the nature of costs between periods. There is no equivalent level of costs in the DPCR5 historical data used for the regressions.	No change.
Quality of service (QoS)	Not adequately explained by cost driver.	No change.
New streetwork costs	Substantial change in the nature of costs between periods.	No change.
Flood mitigation	Costs associated with flood mitigation are dependent on flood plain development outside of DNOs' control and can vary significantly between DNOs.	No longer excluded. These costs are related to network scale, which is reflected in MEAV. All DNOs have incurred such costs over the 13 year period.
BT21C	Few DNOs have costs in this area during RIIO-ED1.	No longer excluded. These costs are related to network scale, which is reflected in MEAV. All DNOs have incurred such costs over the 13 year period.
Losses and environmental	Each scheme is specific to the relevant DNO and the costs within this vary greatly between DNOs.	No longer excluded. Does not meet criteria set. These costs are related to network scale, which is reflected in MEAV. All DNOs have incurred such costs over the 13 year period.

Operational and non-op capex IT&T	We place a 75% on our qualitative analysis in our disaggregated model. We therefore consider it appropriate to exclude these costs from the totex regressions.	No longer excluded. These costs are related to network scale, which is reflected in MEAV. All DNOs have incurred such costs over the 13 year period.
ETR 132 tree cutting activity	Not adequately explained by cost driver.	No longer excluded. These costs are related to overhead line length, which is reflected in MEAV. All DNOs other than LPN have incurred such costs over the 13 year period.
Wayleaves	Not adequately explained by cost driver.	No longer excluded. These costs are related to overhead line supports, which are reflected in MEAV. All DNOs have incurred such costs over the 13 year period.
Third party connections	Not adequately explained by cost driver.	No longer excluded. These costs are related to network scale, which is reflected in MEAV.

Other adjustments

4.57. We make adjustments for costs outside the price control, non-controllable costs and indirect cost allocation in our two totex models and in the disaggregated model. These were supported in responses to our fast-track assessment and again following draft determinations. We see no reason to change our approach.

Costs outside the price control

4.58. We make adjustments for costs outside the price control where the costs relate to activities that should not be funded through the price control. There were no issues raised following draft determinations

Non-controllable costs

4.59. We exclude costs that are subject to cost pass-through mechanisms from the fast-track assessment as there are separate arrangements in place to fund DNOs for these costs.

Indirect cost allocations

4.60. A number of cost activities, in part or in full, are carried out at a group level rather than by individual DNOs, for example BSCs and CAI costs. Each company has its own methodology and preferred cost allocation drivers for allocating such costs between its DNOs and other companies within the same group.

4.61. We use the companies’ own allocations for the purposes of our cost benchmarking.

4.62. Back at fast-track we considered whether companies using different drivers to allocate these costs might distort our totex or disaggregated activity analysis. We ran sensitivity analysis with common allocation drivers for all groups and concluded that it was appropriate to continue to use the companies' own allocations.

Link boxes

4.63. Link box safety has become a high profile issue following a small number of incidents involving explosions under pavements in central London. UKPN in total has over 30% of the country's link boxes. Based on recent incidents it requested an extra £95m for the eight years of RIIO-ED1 to manage this risk. UKPN has working level HSE support. This issue has arisen recently and UKPN did not include it in its plan at draft determinations. We have reviewed the information provided and believe that there is little robust evidence on which to set a credible funding plan for an eight-year period.

4.64. However, this is an important and high profile safety issue. As such we have decided to give UKPN an ex ante allowance for the first two years of RIIO-ED1, so it can do short-term work on link boxes. We have created a re-opener so we can determine an efficient level of expenditure for the remainder of RIIO-ED1. This reopener will also consider the efficient levels of costs for the first two years of RIIO-ED1.

4.65. For the two-year ex ante allowance we have accepted UKPN's proposed volumes but provided for unit costs at the efficient level. The majority of these costs are related to asset replacement. Other costs areas affected are legal and safety, inspection and maintenance and streetworks. As a result of accepting these costs we have disallowed the £0.385m per annum originally requested by UKPN for its regional case for link box inspection.

London strategic investment[18]

4.66. In its business plan, UKPN proposed £100m of strategic investment projects in London. Strategic investment is investment made in network assets in anticipation that customers will subsequently request to make use of them. This raises the difficult question of who should bear the risk (and cost) of the assets if the connecting customers do not emerge. We stated in our strategy decision that we were open to DNOs submitting a case for strategic investment projects in their business plans if they appropriately shared the risk of stranded assets between themselves, connecting customers and all other customers (DUoS customers). We stated that if a DNO could demonstrate benefits to DUoS customers of a strategic approach, then we would consider allowing DUoS customers to fund up to the level they would have done under an incremental approach. We expected DNOs to pass some of the benefits on to DUoS customers in recognition of the increased risk they are taking. UKPN has demonstrated that the strategic investment projects it proposes are significantly lower cost and less disruptive for all its London customers than incremental approaches.

[18] We note that strategic investment is not a normalisation or adjustment, but believe it sits best in this chapter.

4.67. At draft determinations, these projects and associated costs were assessed in detail as part of our disaggregated model including our assessment of reinforcement and benchmarking of high value projects (HVPs). We believed that these projects were justified and allowed the efficient cost of doing this work.

4.68. UKPN disagreed with the level of disallowed costs at draft determinations and submitted additional evidence on reinforcement schemes. We reviewed that evidence and allow additional costs for 24/7 operational presence, unit protection and automated circuit breakers and for certain schemes in the central London area. In return UKPN have put forward tighter CI/CML targets for its LPN business and additional KPIs for key London business districts, which we accept.

5. Totex modelling

Chapter summary

Detail of our two totex models and the changes that have been made since our draft determinations. Results of both models are presented, as are the disaggregated results.

Decision and results

5.1. Collectively the ten slow-track DNOs have forecast that they will spend £17,990m over RIIO-ED1. Both our totex models suggest higher costs of £18,053m.[19] While we use a toolkit with three different modelling approaches, it is notable that they produce a consistent set of results at a total level and for most DNOs. At a total level the difference between the totex models and the disaggregated model is only 2%. Tables 5.1, 5.2 and 5.3 present our results.

Table 5.1: Top-down totex modelled costs (2012-13 prices)[20]

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	1,794	1,927	1,794	1,934	141	8%
NPgN	1,300	1,340	1,305	1,351	46	4%
NPgY	1,725	1,805	1,720	1,790	70	4%
WMID	1,931	1,882	1,931	1,880	-51	-3%
EMID	1,945	2,101	1,945	2,099	154	8%
SWALES	1,011	1,067	1,011	1,079	68	7%
SWEST	1,582	1,383	1,583	1,396	-187	-12%
LPN	1,883	1,803	1,892	1,837	-56	-3%
SPN	1,783	1,808	1,796	1,817	20	1%
EPN	2,652	2,539	2,663	2,517	-146	-5%
SPD	1,496	1,662	1,495	1,662	166	11%
SPMW	1,840	1,637	1,837	1,592	-246	-13%
SSEH	1,170	1,107	1,145	1,095	-50	-4%
SSES	2,343	2,449	2,343	2,460	117	5%
Total	24,456	24,509	24,460	24,507	47	0.2%
Total excl WPD	**17,988**	**18,076**	**17,990**	**18,053**	**63**	**0.3%**

*Costs exclude rail electrification.

[19] Allowances are post reversal of adjustments but before the calculation of the UQ, the application of RPEs, smart grids savings and the IQI interpolation.
[20] The submitted costs in tables 5.1 to 5.3 match those submitted in tables 2.3 and 2.4 in Chapter 2. These tables exclude RPEs. Other tables reported in Chapter 2 report submitted costs including RPEs.

Table 5.2: Bottom-up totex modelled costs (2012-13 prices)[21]

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	1,794	1,881	1,794	1,885	92	5%
NPgN	1,300	1,322	1,305	1,330	25	2%
NPgY	1,725	1,818	1,720	1,800	80	5%
WMID	1,931	1,871	1,931	1,876	-56	-3%
EMID	1,945	2,057	1,945	2,060	116	6%
SWALES	1,011	1,066	1,011	1,077	66	7%
SWEST	1,582	1,432	1,583	1,446	-136	-9%
LPN	1,883	1,757	1,892	1,784	-109	-6%
SPN	1,783	1,770	1,796	1,776	-20	-1%
EPN	2,652	2,595	2,663	2,577	-86	-3%
SPD	1,496	1,653	1,495	1,653	158	11%
SPMW	1,840	1,662	1,837	1,616	-221	-12%
SSEH	1,170	1,112	1,145	1,103	-42	-4%
SSES	2,343	2,520	2,343	2,529	186	8%
Total	24,456	24,515	24,460	24,513	53	0.2%
Total excl WPD	**17,988**	**18,089**	**17,990**	**18,053**	**63**	**0.3%**

5.2. The total modelled costs from our disaggregated model are presented below for comparative purposes. The disaggregated modelled costs are lower than the forecast costs, at £17,678m.

Table 5.3: Disaggregated model totex modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	1,794	1,800	1,794	1,836	42	2%
NPgN	1,300	1,219	1,305	1,241	-64	-5%
NPgY	1,725	1,659	1,720	1,669	-51	-3%
WMID	1,931	1,869	1,931	1,884	-47	-2%
EMID	1,945	1,917	1,945	1,939	-5	0%
SWALES	1,011	1,019	1,011	1,046	35	3%
SWEST	1,582	1,520	1,583	1,552	-31	-2%
LPN	1,883	1,702	1,892	1,767	-126	-7%
SPN	1,783	1,672	1,796	1,702	-94	-5%
EPN	2,652	2,591	2,663	2,632	-30	-1%
SPD	1,496	1,519	1,495	1,562	66	4%
SPMW	1,840	1,752	1,837	1,783	-54	-3%
SSEH	1,170	1,126	1,145	1,144	-2	0%
SSES	2,343	2,311	2,343	2,341	-2	0%
Total	24,456	23,675	24,460	24,098	-362	-1.5%
Total excl WPD	**17,988**	**17,350**	**17,990**	**17,678**	**-313**	**-1.7%**

[21] The submitted costs in tables 5.1 to 5.3 match those submitted in tables 2.3 and 2.4 in Chapter 2. These tables exclude RPEs. Other tables reported in Chapter 2 report submitted costs including RPEs.

5.3. Our approach for the final determinations assessment is in line with our draft determinations approach.

5.4. We have made changes to our assessment in other areas which have had a consequential impact on the inputs to, and results of our totex models.

5.5. These changes are described in more detail in Chapter 4 and include the following:

- changes to our regional labour cost adjustments and company specific factors
- changes to the costs excluded from our assessment that are inappropriate for comparative benchmarking
- changes to our assessment of the SPMW special case.

Draft determinations

Top-down totex

5.6. In the top-down totex model we used regression analysis to determine efficient costs and used a pooled Ordinary Least Squares (pooled OLS) estimator.[22] We used a CSV comprising MEAV and customer numbers. It no longer included network length, or units distributed as it had at fast-track. We used statistical techniques to derive the weights to apply to each driver. We undertook extensive data cleansing allowing us to use MEAV as a cost driver rather than weighted MEAV.[23] We also incorporated a time trend since, relative to fast-track, we were using a longer period of data. This allows us to account for the forecast reduction in costs between DPCR5 and RIIO-ED1.

5.7. We used data from the 13-year period (four historical years and nine forecast years) to estimate the cost parameters instead of only using historical data as we had for the fast-track assessment. We considered that this accounts for changes in technology and was more consistent with our approach for the disaggregated models where we have taken account of a mixture of historical and forecast data. It is also in line with our RIIO principles where we set out that we would place greater weight on forecasts. There were a number of areas, notably closely associated indirect (CAI) costs and business support costs (BSCs), where DNOs had projected significant savings in RIIO-ED1. Basing our analysis only on historical data did not reflect these reductions and overestimated what DNOs required. At fast-track we applied scaling adjustments to bring the overall results of our totex modelling into line with industry forecasts. This was

[22] More detail on pooled OLS used at both draft determinations and final determinations is provided in Appendix 2, 3 and 5.
[23] Unweighted MEAV is a better reflection of network scale than the weighted MEAV which weighted the components of MEAV based on associated asset replacement and refurbishment spend over the first three years of DPCR5. We used weighted MEAV at fast-track because of concerns over the quality of the underlying data. There have been significant improvements in the quality of the data submitted by the DNOs and we have now excluded elements of MEAV where questions remain over the consistency of reporting.

criticised. Using 13 years' data to estimate the model parameters removed the need for such scaling.

5.8. We considered it appropriate to exclude some costs from the main totex modelling because certain activities and costs only concerned a limited number of DNOs (eg RLM), or were subject to different treatments for reasons outside the DNOs' control (eg CNI), or there was a substantial change in the nature of costs between price controls was forecast (eg smart meters).

Bottom-up totex

5.9. In the bottom-up totex model we also used a pooled OLS estimator using data from the 13 year period, with the same exclusions as for the top-down totex model. However, we used different drivers to estimate the efficient costs. This alternative totex model weighted by expenditure the more closely aligned cost drivers from the disaggregated analysis into a single cost driver. We also used a time trend for costs in this model.

Responses

5.10. Responses on our totex modelling raised issues on our corrections to drivers, the number of exclusions we made, and our use of regressions.

5.11. One DNO questioned whether our totex model was appropriate and argued for a different cost assessment approach. Another DNO suggested only using totex modelling as a cross check for the disaggregated modelling.

5.12. Another DNO questioned the relevance of using two MEAV driven models which, in its view, do not provide significantly different ways of assessing totex.

5.13. One DNO noted that we had failed to use the data on customer numbers from DNOs' IIS submissions for the year 2013-14, even though we had used these submissions for all previous years.

5.14. One DNO suggested that more weight should be placed on high-level totex modelling (and less on the bottom-up activity level analysis) in order to avoid giving undue weight to specific points of detail and anomalies arising from boundary issues.

5.15. One DNO felt that the totex models do not deal with differences in scope or volume of works arising from legitimate differences in investment cycles between DNOs. It argued that this led to totex reductions not sufficiently supported by evidence or robust modelling.

Reasons for our decision

5.16. We have not changed our overall totex approach for final determinations. We are confident that our choices of both models and drivers are appropriate. This is supported by results of sensitivity testing including the use of a random effects estimator which produces results in line with our main totex models.

5.17. We investigated and discussed the various cost driver options beyond MEAV for our totex models at draft determinations, particularly the top-down model. A number of these drivers were not advanced due to various statistical issues or counterintuitive signs on parameters, nevertheless the modelling resulted in very similar results. We are satisfied that MEAV is a sensible driver to use in our analysis.

5.18. We use the most up to date actual customer numbers as our driver in our totex modelling.

5.19. Concerning the weighting on our totex models, we have stated throughout the development of RIIO-ED1 that we are using a toolkit approach. In line with the RIIO principles, our preference has been to make more use of totex models for RIIO-ED1. Our approach of applying a 50% weighting to totex and our disaggregated analysis is consistent with our approach at RIIO-GD1.

5.20. The concerns regarding investment cycles have been raised previously in the development of RIIO-ED1. Our preparatory work with Frontier Economics found that investment cycles across the industry were not significantly mis-aligned. We use data from the full 13 year period and DPCR5 was considered a peak period for asset replacement. We consider that this provides a good approach for estimating costs for RIIO-ED1.

6. Load-related expenditure

Chapter summary

Our approach to the assessment of load-related expenditure. It covers primary reinforcement, secondary reinforcement (including low carbon technology reinforcement), transmission connection point charges and connections.

Overview

6.1. The DNOs' business plans included a range of measures to accommodate and account for forecast changes in demand during RIIO-ED1. For our assessment we have broken down our analysis of load-related expenditure by the technical nature of the activity.

6.2. The load-related expenditure categories are:

- reinforcement, which is broken down into the following activities:
    - primary reinforcement schemes
    - n-1 primary reinforcement
    - low carbon technology (LCT) driven reinforcement
    - secondary reinforcement (non-LCT)
    - fault level reinforcement
- transmission connection point (TCP) charges
- connections.

Reinforcement

Results

6.3. The five reinforcement activities are assessed separately. We describe our final determinations decision, our draft determinations approach, responses to draft determinations and reasons for our decision for each separately. The combined results are presented in Table 6.1.

6.4. In total, the ten slow-track DNOs estimated that they will spend £1,688m on reinforcement activities in RIIO-ED1. Our modelled costs are £1,668m, £21m (1.2%) lower than DNO forecast costs.

6.5. DNOs submitted additional costs since draft determinations. This is due to the movement of costs from connections to reinforcement for NPgN. Our modelled costs also increased by £57m.

Table 6.1: Reinforcement modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	103	108	103	108	4	4%
NPgN	82	79	101	87	-14	-14%
NPgY	100	92	100	93	-8	-8%
WMID	187	172	187	173	-14	-7%
EMID	259	226	259	227	-32	-12%
SWALES	43	62	43	62	20	46%
SWEST	80	81	80	81	0	1%
LPN	338	284	338	296	-41	-12%
SPN	178	172	178	172	-6	-3%
EPN	284	333	284	335	51	18%
SPD	133	132	133	146	13	10%
SPMW	155	150	155	169	14	9%
SSEH	57	55	57	56	-2	-3%
SSES	239	205	239	207	-32	-14%
Total	2238	2152	2258	2211	-47	-2.1%
Total excl WPD	**1669**	**1611**	**1689**	**1668**	**-21**	**-1.2%**

Primary network reinforcement (n-2)

Decision

6.6. We made no changes to our draft determinations approach. All primary network reinforcement schemes were assessed by comparing the submitted unit costs to our view of unit costs for asset replacement at draft determinations. We did not revisit these schemes for final determinations.

Draft determinations

6.7. For draft determinations DNOs were required to provide a list of asset installations and disposals for each proposed primary network reinforcement scheme in RIIO-ED1. We split the costs of these schemes across asset types. We used the unit costs of assets as determined in our asset replacement model. This approach is detailed in Chapter 7 (paragraphs 7.10 to 7.14).

6.8. Across each reinforcement scheme, we compared the submitted unit costs to our view of unit costs for asset replacement. We applied a percentage adjustment (positive or negative) to each DNO's unit costs.

Responses

6.9. One DNO raised a concern about the model's ability to cope with some of the more complex reasons for reinforcement at primary network voltage levels, particularly ER P2/6.[24] Following discussions, the DNO understood that we reviewed every individual scheme and is now content the issue has been addressed.

Reason for our decision

6.10. We did not change our draft determinations approach as we are confident with the methodology.

6.11. We are confident that this line by line review of asset replacement unit costs is robust. We begin by calculating an industry median unit cost and through expert review make any necessary adjustments to an asset's unit cost for each DNO. This technical review considered the DNOs' historical and forecast derived unit costs, supporting evidence provided by DNOs and information contained within scheme papers and CBAs.

Primary reinforcement (n-1)

Decision

6.12. We continue to use our draft determinations approach. This includes both unit cost and volume assessment. We made a small qualitative volume adjustment for SPMW, as we believe its n-1 primary reinforcement volumes are efficient.

Draft determinations

6.13. We modelled expenditure relating to n-1 primary reinforcement and other work captured in the load index (LI) secondary deliverables using a bespoke assessment. This included the following:

- **unit costs:** the eight-year RIIO-ED1 forecast for reinforcement work covered by the LI was adjusted by the average percentage adjustment from the following calculations:
    - the difference between the DNO view of unit costs in scheme papers and our view of unit costs
    - the difference between the DNO and industry median unit cost of delivering one MVA of capacity from n-1 primary network reinforcement schemes
    - the median ratio of the DNO forecast unit costs for delivering one MVA of additional capacity and the historical unit cost of delivering one MVA of additional capacity based on dividing the MEAV for EHV+ assets by the firm capacity presently on the network

[24] Engineering Recommendation P2/6 is the current distribution network planning standard.

- **volumes**: for the relevant schemes in each DNO's business plan, the ratio of forecast capacity added, relative to the increase in demand above firm capacity was benchmarked at the industry average. Where a DNO's forecast was above the average we reduced it to the average. Otherwise we made no adjustment.

6.14. For each DNO assessed as inefficient by our quantitative analysis, either in terms of capacity added or unit costs, we identified a list of schemes that fell outside our benchmark. To identify these schemes we used our ratio benchmarks from our volume assessment. Our technical consultants then reviewed a sample of these schemes to determine whether the costs were efficient. We prioritised our review on the outlier schemes of greatest value. The review included both the needs case and the efficiency of the proposed solution. We compared our efficient view of the sample of schemes to the DNO forecast. The efficient funding for the outlier schemes in total was based on our percentage adjustment to the reviewed schemes. Each individual scheme that lay within our benchmarks was deemed to be efficient.

6.15. Our technical consultants provided their view of the appropriate costs for the schemes reviewed. Where they were uncertain of needs case or the efficient costs, we adjusted the costs of these schemes down to the benchmark of the quantitative modelling.

Responses

6.16. UKPN believed the adjustments to reinforcement schemes were unjustified and submitted additional evidence and repackaged existing evidence to support their case. These schemes mainly related to its London network investment strategy. UKPN felt that as these schemes were part of combined projects they should be reviewed together.

6.17. One DNO raised a concern over the model's ability to cope with some of the more complex reasons for reinforcement at primary network voltages, particularly P2/6.

Reason for our decision

6.18. We revisited 16 UKPN reinforcement schemes along with our engineering consultants. We asked UKPN further questions and considered the schemes' contributions to the larger combined projects. As a result, five schemes receive an improved RAG rating and we updated our qualitative assessment accordingly. LPN and EPN receive positive volume adjustments, with the largest adjustment for LPN.

6.19. We are confident in the completeness of our analysis. It combines a quantitative assessment of unit costs and volumes and a qualitative review of scheme papers. By reviewing the schemes that are outliers in the benchmarking, we cover the more complex reinforcement cases such as P2/6.

LCT reinforcement

Decision

6.20. We have not changed our draft determinations approach.

Draft determinations

6.21. For volumes, we benchmarked each DNO's eight-year RIIO-ED1 forecast of network interventions per MW of LCTs connected to the industry median. For unit costs, we benchmarked each DNO's eight-year forecast of unit cost per LCT related intervention to the industry median. WPD included clustering assumptions that substantially drove up its number of network interventions per MW of LCTs connected, which was not in line with all other DNO assumptions. Therefore, we made a qualitative adjustment which accepted WPD's assumptions where they were appropriate, and brought their forecasts in line with other DNOs.

6.22. We excluded NPgN, NPgY and ENWL's cost forecasts for the unbundling of shared service cables from our modelling and subjected them to a separate technical review.

Responses

6.23. The majority of DNOs agreed with our approach. However, one suggested that DNOs who used the outputs from the Transform model in their forecasts, should have been excluded from benchmarking. They argued that the standardised calculations performed by the Transform model would be sufficient to determine efficiency and that we should allow the DNOs' forecasts.

Reason for our decision

6.24. The Transform model is not a benchmarking tool and gives DNOs control over a large number of inputs.[25] We expected DNOs to use this model alongside other evidence and a number of DNOs adjusted the outputs of the model. The DNO did not provide evidence demonstrating that it is inconsistent or incorrect to benchmark DNOs' forecasts.

[25] More information on the Transform model can be found in the publications on the SGF web page: https://www.ofgem.gov.uk/electricity/distribution-networks/forums-seminars-and-working-groups/decc-and-ofgem-smart-grid-forum

Secondary reinforcement (non-LCT)

Decision

6.25. We continued to use our draft determinations approach.

Draft determinations

6.26. The volume of interventions and capacity released are difficult to capture for reinforcement of the secondary network not attributable to LCT. We first applied the median DNO forecast of interventions and capacity released and then applied an adjustment based on the following network characteristics of each DNO:

- DNO HV/LV MEAV as a percentage of the industry median HV/LV MEAV. Our modelled costs were reduced where a DNO had smaller than median secondary network MEAV and increased where a DNO had a larger than median secondary network MEAV.
- The percentage of DNO total MEAV that relates to HV/LV assets as a percentage of the industry median. We reduced our modelled costs where a DNO had a smaller than median percentage of its overall MEAV made up of secondary network assets. We increased modelled costs where a DNO had a larger than median percentage of its overall MEAV made up of secondary network assets.
- We cross-referenced the results of the modelling with the efficiency of the unit costs forecast for any MVA of capacity across the secondary network to determine whether any qualitative adjustments were required. In the cases where contrasting results (ie positive and negative) were found we applied qualitative adjustments to reflect the additional unit cost analysis.

Responses

6.27. One DNO raised concerns with the use of HV and LV MEAV as a cost driver for HV and LV reinforcement. It stated that this both ignored actual network requirements (current loading, growth hotspots) and rewarded past inefficiency.

6.28. LPN said that the draft determinations resulted in a reduction in expenditure for central London HV reinforcement in relation to unit protection and remote control automated circuit breakers (ACBs). It argued that these schemes support a complex network configuration key to maintaining and improving the resilience and reliability in central London.

Reasons for our decision

6.29. The DNO that raised using HV and LV MEAV as a cost driver has subsequently accepted that we had sufficiently corrected the output of the model by applying a qualitative adjustment. We remain confident that our approach is appropriate.

6.30. For the central London schemes, we reviewed the submitted information together with our technical consultants. The specific adjustment for unit protection and remote control ACBs is included in LPN's regional adjustment, discussed in Chapter 4 and Appendix 9. As such we do not make a further adjustment in our disaggregated model as this would be double counting.

Fault level reinforcement

Decision

6.31. We continued to use our draft determinations approach. We reviewed additional evidence and made a qualitative adjustment for one of NPgN's fault level reinforcement schemes.

Draft determinations

6.32. For unit costs we conducted two unit cost assessments. First, we benchmarked the unit cost of each individual fault level activity within the fault level reinforcement categories at a disaggregated level. Second, we grouped activities by voltage, and calculated median industry unit costs. This accounted for boundary issues between asset replacement and operational solutions to fault level issues. The DNOs were given the more generous unit cost of the two approaches.

6.33. To account for a variation in the interpretation of the volumes, we applied a qualitative adjustment to ENWL. We also applied a qualitative adjustment to SPMW to account for its outlying unit costs. We accepted the forecast fault volumes of all DNOs.

Responses

6.34. No issues were raised on our draft determinations assessment of fault level reinforcement.

Reason for our decision

6.35. We are confident in our approach. NPgN submitted additional information for a fault level reinforcement scheme. The scheme was initially reported as a connection project, but since draft determinations the project has been cancelled. NPgN resubmitted part of the cost in fault level reinforcement. We completed a purely qualitative assessment of this scheme with our technical consultants and accept only part of the submitted costs. We accept the needs case but based on the evidence provided we allow the costs for the least expensive technical solution of the options proposed by NPgN.

TCP charges

Decision and results

6.36. We continue to use our draft determinations approach.

6.37. The submitted costs increased by £3m. As at draft determinations, we made no reductions to the DNO forecasts for TCP charges.

Table 6.2: TCP charges total modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	6	6	6	6	0	0%
NPgN	7	7	9	9	0	0%
NPgY			0	0	0	
WMID	2	2	2	2	0	0%
EMID	1	1	1	1	0	0%
SWALES			0	0	0	
SWEST			0	0	0	
LPN	41	41	41	41	0	0%
SPN	22	22	22	22	0	0%
EPN	14	14	14	14	0	0%
SPD	8	8	8	8	0	0%
SPMW			0	0	0	
SSEH	53	53	53	53	0	0%
SSES	4	4	4	4	0	0%
Total	159	159	161	161	0	0.0%
Total excl WPD	**156**	**156**	**159**	**159**	**0**	**0.0%**

Draft determinations approach

6.38. Our consultants carried out an engineering review of the DNOs' forecasts for TCP charges. We based our results on their qualitative assessment.

Responses

6.39. Responses received from the DNOs were generally supportive of our draft determinations approach.

Reasons for our decision

6.40. We are confident the approach used at draft determinations is appropriate and have decided to retain this.

Connections

Decisions and results

6.41. We have not altered our approach from draft determinations. As noted in the reinforcement section above, NPgN moved £16m of costs out of connections and into reinforcement.

6.42. Our modelled costs for the ten slow-track DNOs' is £181m, £19m or 9.6% less than submitted costs.

Table 6.3: Connections modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	31	26	31	26	-5	-16%
NPgN	21	7	5	6	2	41%
NPgY	6	6	6	9	3	54%
WMID	19	20	19	20	1	7%
EMID	17	18	17	18	0	3%
SWALES	9	8	9	8	-1	-8%
SWEST	9	11	9	11	2	22%
LPN	13	10	13	11	-2	-14%
SPN	22	18	22	20	-1	-6%
EPN	47	45	47	46	-1	-2%
SPD	5	3	5	3	-1	-27%
SPMW	24	23	24	22	-1	-5%
SSEH	30	21	30	21	-9	-29%
SSES	21	16	21	16	-4	-21%
Total	271	233	255	238	-16	-6.4%
Total excl WPD	**217**	**176**	**201**	**181**	**-19**	**-9.6%**

Draft determinations

6.43. We applied qualitative adjustments to volumes and unit costs. Where relevant these were applied at the disaggregated voltage level.

6.44. Our volume assessment considered the justifications provided by the DNOs, alongside the submitted data. For particular DNOs the volumes for RIIO-ED1 were significantly higher than their DPCR5 volumes. We assessed these DNOs' efficient volumes by calculating their annual average volumes for 2013-14 and 2014-15 then applied these across the eight-year RIIO-ED1 period.

6.45. We based our unit cost assessment on the average of the industry's RIIO-ED1 median and the DNO's own or industry DPCR5 median unit cost. This was applied to the DNOs' modelled volumes for RIIO-ED1. For DUoS customer funded HV demand connections, we set unit costs for all DNOs at their RIIO-ED1 forecast unit costs as unit costs across the DNOs varied significantly.

Responses

6.46. DNOs felt that our assessment was appropriate. One DNO said we should be mindful that costs for connections activity may vary in RIIO-ED1 compared with historical costs. This is due to the impact of smart grids, smart metering, and the increased adoption of LCT.

Reasons for our decision

6.47. We think that our draft determinations approach continues to be the most appropriate.

6.48. We have reclassified one project for NPgN. This was due to the customer cancelling the connection project in March 2014. NPgN feel that reinforcement work still needs to be carried out on the network in this area, and re-submitted their cost forecasts for this project as reinforcement expenditure and volumes. This project has been assessed in line with our fault level reinforcement approach.

7. Asset replacement, refurbishment and civils

Chapter summary

The results and our approach to assessing the key components of network investment costs (asset replacement, refurbishment and civil works) and high value projects.

Overview

7.1. Asset replacement, refurbishment and civils costs comprise the majority of non-load-related network investment costs.[26] The remainder of non-load-related network investment cost (non-core costs) are discussed in Chapter 8.

Asset replacement

Decision and results

7.2. We made no changes to our overall approach, but changed some qualitative adjustments. Full details of these, by DNO and by asset type, are provided in Appendix 7.

7.3. We continue to use a bespoke age-based survivor model, run rate analysis and qualitative assessment to determine our efficient view of volumes. We use median unit cost analysis and expert review to determine our efficient view of unit costs.

7.4. The ten slow-track DNOs forecast that they would spend £3,349m on asset replacement in RIIO-ED1. Our efficient view of these costs is lower at £3,058m, representing a difference of £292m (8.7%).

7.5. Issues relating to link boxes explain the increase in submitted costs from the three UKPN DNOs increased from draft to final determinations.

7.6. The modelled costs increased from draft to final determinations for eight of the ten slow-track DNOs. This is explained largely by allowing more of the DNOs' submitted volumes of work.

[26] Civils refer to civil engineering work associated with DNO network assets, including buildings and site works at substations.

Table 7.1: Asset replacement modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	365	344	365	350	-15	-4%
NPgN	270	258	270	259	-10	-4%
NPgY	346	301	346	318	-28	-8%
WMID	420	433	420	437	18	4%
EMID	349	375	349	377	27	8%
SWALES	247	247	247	247	0	0%
SWEST	373	360	373	366	-7	-2%
LPN	292	243	298	241	-57	-19%
SPN	281	232	289	258	-31	-11%
EPN	434	331	437	353	-84	-19%
SPD	241	235	241	236	-5	-2%
SPMW	429	387	429	400	-29	-7%
SSEH	205	185	205	186	-19	-9%
SSES	470	457	470	457	-14	-3%
Total	4,720	4,386	4,738	4,484	-254	-5.4%
Total excl WPD	**3,331**	**2,972**	**3,349**	**3,058**	**-292**	**-8.7%**

Draft determinations

7.7. We used an age-based survivor model, run rate analysis and qualitative assessment to determine our efficient view of volumes. We used median unit cost analysis and expert review to determine our efficient view of unit costs. Key components of our approach were as follows:

- Those assets for which we have an age profile were subjected to the age-based model to assess volumes. Assets without age profiles were subjected to run rate analysis.
- We ran the age-based model using two age profiles with the results of both factored into our final volume assessment. This ensured the modelling was based on both historical and forecast data.
- We subjected both the volume and unit cost assessments to further qualitative review.
- We considered each asset on an individual, line by line basis.
- We made use of the health index data in our volume assessment.

Volume assessment

7.8. All assets with an age profile were subjected to a bespoke age-based model. We assessed each DNO's forecast volume against the modelled volumes. Where a DNO's forecast volumes were below our modelled volumes, the DNO received its own volumes. Where a DNO's forecast volumes were above our modelled volumes, the DNO either received its own volumes, the average between the two modelled volumes or the average of the lowest modelled volume and its own forecast volumes. The final volumes received depended on the outcome of a line-by-line qualitative assessment. Appendix 8 provides full details of our age-based model approach.

7.9. For the non-modelled volumes we used trend analysis to review the DNOs' submitted volumes for a number of asset categories not suitable for the age based model, eg where there were issues over the data or the spread of the implied asset lives was very large. In such cases we used replacement run rates based on submitted disposal volumes as a proportion of DNO assets in service. In most cases we applied the industry median benchmark to represent efficient replacement volumes. Due to the variable quality of the asset replacement data submitted by DNOs we applied our view of benchmark replacement volumes for some asset categories taking into account the industry median and other supporting information.

Unit cost assessment

7.10. We multiplied our view of efficient forecast volumes by a benchmarked unit cost to set the base model asset replacement costs

7.11. We applied a unit cost reduction where the DNO's forecast unit cost was higher than our benchmark. The unit cost reduction did not impact on the volume of work.

7.12. Determining a benchmarked unit cost for asset replacement activities is not straightforward. We worked with engineering consultants to set unit costs. We set a unit cost for all assets on a line by line basis. We applied one of four unit costs:

- industry median based on four years of actual data (the first four years of DPCR5)
- industry median based on eight years of RIIO-ED1 data
- industry median based on 13 years of data (all DPCR5 and RIIO-ED1)
- qualitative view of unit cost.

7.13. We took a number of factors into account when deciding which unit cost to apply including:

- the DNOs historical and forecast derived unit costs (ie forecast expenditure divided by volume)
- the sample size
- supporting evidence provided by DNOs
- information contained within scheme papers and CBAs
- independent views and technical evidence provided by our technical consultants.

7.14. Our approach followed careful review and due consideration to ensure that the median values reflected the scope of works being proposed by the majority of DNOs and that any exogenous factors and any outliers were accounted for.

Responses

7.15. Three DNOs raised issues with our assessment of particular assets. In total, issues were raised with 27 different assets. The issue raised for each asset varied. The detail of this and our responses are provided in Appendix 7.

7.16. One DNO questioned using median unit costs for benchmarking, particularly where there were relatively low volumes of activities and different scopes of work across the industry. The same DNO also said that it was unclear how expert unit costs were established.

7.17. Another DNO questioned the validity of the age-based asset replacement model. It stated that the model failed to capture company specific factors and recognise bespoke programmes of work.

Reasons for our decision

7.18. We have not changed our approach other than to revisit specific cases for making qualitative adjustments to our modelled costs. We believe the method for setting unit costs at draft determinations is justified.

7.19. We disagree that our approach does not account for different scopes of work. We, in consultation with the DNOs, have defined the scope of work included as part of the asset replacement activity for each of the assets associated with the electricity distribution network. The scope as defined by the DNOs in the RIGs sets out all the costs that lie within or outside the cost of replacing the prime asset. The RIGs give us security that all DNOs are reporting correctly and support our benchmark unit costs.

7.20. DNOs challenged us on areas where our modelled view of costs was lower than their submitted costs. They did not identify areas where they were outperforming our benchmark unit cost. If we did not allow for the netting off of assets with higher unit costs against assets with lower unit costs we would be cherry picking and setting unachievable levels of efficiency.

7.21. We have reviewed in detail the issues raised on our unit cost benchmarks by the DNOs. We requested further evidence in some cases, and made amendments to our analysis based on the information provided. We believe our approach is robust and have made adjustments where there are separately defined unit costs. We do not accept the argument that the modelled unit costs are unachievable. We have used the median. That by definition means 50% of DNOs are already outperforming the benchmark for that activity. Full details of the issues raised and our response is in Appendix 7.

7.22. The difference in DNOs' own unit cost forecasts at fast-track and slow-track was a major concern for us. We expected to see further efficiencies in unit costs between the fast-track and slow-track. However, in some cases the unit costs increased. Where this occurred we relied on our technical experts to assess whether our benchmark was still appropriate based on the DNOs' justification.

7.23. The age-based asset replacement model is part of a toolkit to assess asset replacement costs. The model itself is not programmed to identify company specific factors but we subject the modelled volumes to a detailed qualitative review. Company specific factors put forward by the DNOs were reviewed and accounted for by making a qualitative adjustment where appropriate. All qualitative adjustments made after draft determinations are listed and explained in Appendix 7.

Refurbishment

Decision and results

7.24. We made no changes to our overall approach to assessing efficient refurbishment costs. We continue to use run rate analysis and qualitative assessment to set our efficient view of volumes. We apply our view of unit costs which is based on median unit cost analysis and technical review. We made some changes to the qualitative adjustments and corrected an error.

7.25. As detailed in Table 7.2, the ten slow-track DNOs forecast that they would spend £586m on refurbishment works in RIIO-ED1. The forecast costs did not change from draft determinations. Our efficient view of these costs is lower at £479m, representing a difference of £107m (18.2%).

7.26. Our modelled costs at final determinations are £28m more than at draft determinations. This is explained by increased modelled costs for ENWL, NPgN, NPgY, SPMW and SSEH.

7.27. ENWL found an error in our calculation of the volume trade-off between asset replacement and refurbishment which we corrected. NPg highlighted an error where we were not providing it volumes for the health improvements it had identified in its plan. We made adjustments to NPg's EHV tower unit costs and SPMWs 132kV tower unit cost due to atypical projects which are described in Appendix 7.

Table 7.2: Refurbishment modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	109	90	109	96	-12	-11%
NPgN	61	36	61	45	-17	-27%
NPgY	78	53	78	59	-19	-25%
WMID	29	32	29	32	3	10%
EMID	25	27	25	27	2	9%
SWALES	20	22	20	22	1	7%
SWEST	27	32	27	32	5	19%
LPN	15	15	15	15	0	-1%
SPN	24	22	24	22	-2	-8%
EPN	31	28	31	28	-2	-7%
SPD	50	44	50	44	-6	-12%
SPMW	95	49	95	52	-42	-45%
SSEH	28	28	28	32	3	12%
SSES	95	86	95	86	-9	-9%
Total	686	563	686	591	-95	-13.9%
Total excl WPD	**586**	**451**	**586**	**479**	**-107**	**-18.2%**

Draft determinations

7.28. Our unit cost assessment for refurbishment fell into two categories. First those assets that are on the asset replacement register and had a sufficient sample size. Second those assets that were not on the asset replacement register or did not have a sufficient sample size.

7.29. For those in the first category, we calculated the unit cost ratio of asset refurbishment to asset replacement for each asset for each DNO. This took DNOs' own views of unit cost for refurbishment and asset replacement and used 13 years' of data. We then applied the median industry ratio for each asset to our asset replacement view of unit cost for all DNOs. This gave an initial view of unit cost for refurbishment for each asset. We made changes to this initial unit cost only when justified by qualitative evidence, such as different scopes of work.

7.30. For those in the second category, we applied a qualitative view of unit costs following a review by our consultants of the information provided by DNOs.

7.31. We used our asset replacement age-based model to set the refurbishment volumes. DNOs received their own refurbishment volumes if their submitted volumes combined with their asset replacement volumes fell under 110% of our asset replacement modelled view. Otherwise they received the modelled view. However, where a DNO identified refurbishment of an asset that is agreed in its secondary deliverables for health and criticality we gave the DNO the volumes requested.

Responses

7.32. Two DNOs raised issues with our assessment of the refurbishment costs of particular assets. In total, issues were raised with six different assets. The issue raised with each asset varied. The detail of this and our responses are provided in Appendix 7.

7.33. Four main points were raised on our refurbishment assessment:

- it was unclear how unit costs were set
- we did not recognise that the variances in costs between assets in the same category were due to different scopes of work
- the small sample sizes were not addressed when using the industry median unit cost
- the model failed to capture company specific factors and recognise bespoke programmes.

Reasons for our decision

7.34. We disagree that we did not factor in sample sizes and justifiable variances in unit costs at draft determinations. Every modelled unit cost was overlaid by a qualitative review that considered these factors and adjustments were made where the evidence submitted was strong enough to justify a change.

7.35. The modelled volumes from our age-based model were subjected to a detailed qualitative review by our consultants when reviewing asset replacement.

7.36. The reasons for our decision by DNO and by asset category are provided in Appendix 7.

Civil works

7.37. Civil work costs are reported under two main categories:

- **Civil works driven by the condition of civil items**: DNOs report a breakdown of works carried out at indoor and outdoor substations as well as cable tunnels, cable bridges and street furniture. The detail of works carried out at each substation is recorded by voltage level (eg roofs, doors, enclosures and surrounds etc, at LV, HV, EHV and 132kV).
- **Civil works driven by plant asset replacement:** DNOs report the number of items where civil works has been undertaken as a result of the replacement of an asset. The categories of civil works here are new builds, plinths and groundworks, buildings, enclosures and surrounds. The work for each of these is recorded by voltage level.

Decision and results

7.38. We made no changes to the approach at draft determinations and no changes to the modelled costs. For each detailed cost area, we continue to use the median run rate as a percentage of the asset base to model volumes and the industry median using eight years of RIIO-ED1 to set unit costs.

7.39. As detailed in Table 7.3, the ten slow-track DNOs forecast that they would spend £554m on civil works in RIIO-ED1. Our efficient view of these costs is lower at £521m representing a difference of £34m (6.1%).

Table 7.3: Civil works modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	76	84	76	85	9	12%
NPgN	38	28	38	28	-10	-26%
NPgY	67	49	67	50	-17	-25%
WMID	63	36	63	35	-27	-43%
EMID	55	54	55	53	-2	-3%
SWALES	24	21	24	21	-3	-11%
SWEST	44	28	44	28	-15	-35%
LPN	69	39	69	38	-31	-45%
SPN	43	61	43	60	17	39%
EPN	84	88	85	87	3	3%
SPD	48	47	48	47	-1	-2%
SPMW	76	55	76	55	-21	-28%
SSEH	14	22	14	22	8	53%
SSES	38	48	38	48	9	25%
Total	739	658	739	658	-80	-10.9%
Total excl WPD	**554**	**520**	**554**	**521**	**-34**	**-6.1%**

Draft determinations

7.40. For draft determinations the volume assessment applied the industry median run rate as a proportion of the total asset base, for each detailed cost area. For unit costs, we applied the industry median unit costs using RIIO-ED1 data. We worked together with our engineering consultants to provide qualitative adjustments to our base model where there was a justifiable case.

Responses

7.41. One DNO suggested that using median unit costs and median volumes was inappropriate as it failed to capture DNO's different scopes of work. Another felt that the analysis did not take in to account the nature of its network, especially the different costs between the 33kV and 66kV assets. Both suggested greater use of qualitative adjustments.

7.42. Another DNO questioned whether we had sufficiently aligned asset replacement and civil works assessments.

Reasons for our decision

7.43. We recognise that civil works is an area that is difficult to benchmark. In recognition of this we did not mechanistically apply median unit costs and median volumes. We removed the ratchet, asked DNOs a number of supplementary questions to ensure the quality of the data and made positive qualitative adjustments where sufficient justification was provided. In addition we asked our technical consultants to review our analysis in relation to the asset replacement results.

7.44. We conducted further review of specific areas following issues raised by DNOs. For 33kV and 66kV assets, we analysed the unit costs of EHV substations based on the percentage of 66kV assets. The analysis did not show any consistent difference in unit costs and therefore we made no adjustments.

High Value Projects (HVPs)

Decision and results

7.45. We made no changes to the approach at draft determinations in assessing HVPs and there are no changes to our results.

7.46. Three DNO groups submitted a total of seven HVPs, totalling £235m. It is estimated that £181m of this will be incurred in RIIO-ED1. Following a review of these projects and their associated costs, our view of efficient costs is £171m, a difference of £10m (6%). Based on our analysis and a technical assessment, three projects receive the full submitted costs. We have applied reductions to the remaining four projects. The details are in Table 7.4.

Table 7.4: High value projects costs (2012-13 prices)

Type	DNO	Project cost (£m)	DPCR5 cost (£m)	RIIO-ED1 submitted costs (£m)	Expert view of scheme costs (£m)	RIIO-ED1 expert view of costs (£m)	Change (expert view to submitted) (%)
Load-related	NPgY	39	28	11	39	11	-1.6%
Load-related	LPN	31	5	26	29	23	-9.4%
Load-related	LPN	44	7	37	43	36	-1.6%
Non-load-related	LPN	26	0	26	26	26	-0.1%
Non-load-related	SPN	37	6	31	33	28	-11.2%
Both	EPN	30	8	22	30	22	0.0%
Load-related	SSES	29	0	29	25	25	-12.9%
Total		235	54	181	225	171	-5.7%

Draft determinations

7.47. The submitted scheme papers were assessed by our technical consultants. Where the information provided was insufficient DNOs were asked supplementary questions. In addition, the forecast costs were compared with our disaggregated analysis. For any HVP that started in DPCR5, we consider the cost of the projects as a whole and adjust our view based on the RIIO-ED1 proportion of costs. We did this by looking at the ratio of the expected expenditure on these projects against the DPCR5 final allowance and factored this into our adjustments for forecast costs. We ensured that this modelled view would not impact on the final assessment of the DPCR5 HVP re-opener mechanism.

Responses

7.48. Two DNO supported our approach. One DNO suggested we have three windows for re-openers on HVP instead of two. Another raised concerns over the qualitative adjustment methodology.

Reasons for our decision

7.49. We did not make any changes to our draft determinations approach as we are confident that our approach on HVP is sufficient and robust.

7.50. We worked closely with our technical consultants and asked a number of supplementary questions to ensure that we have good understanding of each proposal. Before making any adjustments, the submitted costs and volumes were compared against our view of unit costs and volumes and costs from similar projects.

7.51. We believe that two reopener windows in RIIO-ED1 are sufficient to cover for any uncertainty related to HVPs.

8. Non-core expenditure

Chapter summary

Our approach to and results of the non-core non-load-related expenditure, which comprises 12 different categories.

Overview

8.1. The non-core non-load-related expenditure comprises 13 categories as follows:

- operational IT & telecoms (IT&T)
- diversions
- ESQCR
- legal and safety
- quality of supply (QOS)
- flooding
- BT21C
- losses and environment
- high impact low probability (HILP)[27]
- critical national infrastructure (CNI)
- black start
- rising and lateral mains (RLMs)
- improved resilience.

8.2. Each category is considered in turn.

Operational IT and Telecoms

Decision and results

8.3. For IT&T we made no changes to our overall approach but asked our consultants to review the qualitative assessment in light of responses from the DNOs and new evidence submitted. We applied a 25% weighting to the quantitative results and 75% weighting to our qualitative results, as we did in draft determinations. Our quantitative assessment combined the non-operational capex costs with operational IT&T costs. We applied an industry median unit cost, calculated using 13 years of actual and forecast data and MEAV as the cost driver.

[27] No expenditure was put forward by the DNOs at fast-track or slow-track.

8.4. For NPg we continued to allow both DNOs the submitted costs for operational IT&T. This is to allow for its proposed investment during RIIO-ED1 in smart enablers that deliver benefits during the RIIO-ED2 period.

8.5. Over the RIIO-ED1 period the DNOs are forecasting to spend on average 38% more annually on operational IT&T than in DPCR5. The common reasons cited for this were to improve IT capability and to improve customer service. The significant increase in IT costs and the various reasons stated for the increase led us to give more weight to the qualitative assessment carried out by the consultants.

8.6. While the ten slow-track DNOs submitted £365m in operational IT&T costs for RIIO-ED1 our view of efficient costs is lower at £346m, a difference of £19m (5.2%).

8.7. There are no changes to the submitted costs since draft determinations but modelled costs have increased by £9m. The changes are due to amendments to the qualitative assessment.

8.8. Our modelled costs are considerably lower than ENWL's submitted costs. Despite recommending greater cost allowances than at draft determinations our consultants found that there were costs across all elements of ENWL's operational IT&T costs that were not justified; control centre hardware and software, communications for switching and monitoring and substation RTUs, marshalling kiosks and receivers.

Table 8.1: Operational IT&T modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	66	46	66	50	-16	-24%
NPgN	23	23	23	23	0	0%
NPgY	42	42	42	42	0	0%
WMID	24	24	24	25	0	1%
EMID	26	27	26	27	1	5%
SWALES	24	22	24	22	-1	-6%
SWEST	24	23	24	23	-1	-4%
LPN	49	40	49	45	-4	-8%
SPN	37	32	37	32	-5	-13%
EPN	47	45	47	45	-2	-4%
SPD	21	22	21	22	2	7%
SPMW	33	39	33	33	0	1%
SSEH	18	18	18	18	0	-2%
SSES	30	31	30	36	6	21%
Total	463	433	463	443	-20	-4.3%
Total excl WPD	**365**	**337**	**365**	**346**	**-19**	**-5.2%**

Draft determinations

8.9. We assessed operational IT&T both quantitatively and qualitatively. Given the depth of the qualitative assessment and the fact that it could take account of justifiable differences between individual DNOs' IT strategies, we gave it a 75% weighting and gave a 25% weighting to the quantitative assessment.

8.10. In our quantitative assessment, operational IT&T was combined with the non-operational capex IT&T costs. We applied an industry median unit cost, calculated using 13 years data and MEAV as the cost driver. Using the full 13 years of data smoothed the lumpy nature of the capex expenditure. It is reasonable to expect that the scale of the network, as captured in MEAV, drives the capex IT. However, we recognised that there are limitations to the explanatory power of MEAV on IT&T costs and this is why we placed greater weight on the qualitative assessment. Our modelled costs were reallocated to operational IT&T and non-op capex IT&T based on the ratio of submitted expenditure in these two areas.

8.11. Our consultants (DNV GL) completed a qualitative assessment of the DNOs' IT&T expenditure. This involved a review of all DNOs' IT&T strategies. They reviewed the costs submitted by each DNO for operational IT&T, non–operational capex IT&T and business support IT&T (opex).

8.12. Following an initial review, our consultants discussed preliminary findings with the DNOs and requested further information. The results were also reviewed on an ownership group level and cross checked with Ofgem's quantitative analysis. The qualitative assessment results were then combined with the Ofgem quantitative assessment results.

8.13. We awarded NPg its submitted operational IT&T costs for both NPgN and NPgY. In our strategy decision[28] we encouraged all DNOs to consider the impact of investment in RIIO-ED1 on future price controls. NPg proposed smart enablers during RIIO-ED1 that will deliver benefits during the RIIO-ED2 period. This investment is largely for communications and IT equipment to enable the quick deployment of smart grids solutions.

8.14. We reviewed the submitted CBAs with our consultants. We concluded the investment is likely to deliver significant benefits to consumers through avoided reinforcement costs in subsequent price controls. We will recover all or part of the allowed expenditure on behalf of consumers when setting NPg's RIIO-ED2 allowances if it does not demonstrate it has invested efficiently to deliver the promised benefits for consumers.

Responses

8.15. Two DNOs agreed with our approach. One of these DNOs noted that it believed that its operational IT&T plan was misinterpreted. It also stated that costs were unfairly disallowed due to classification issues.

[28] https://www.ofgem.gov.uk/publications-and-updates/strategy-decision-RIIO-ED1-overview

Reasons for our decision

8.16. DNOs either explicitly supported or did not object to the IT&T assessment. Responses suggested misinterpretations in the qualitative assessment. Therefore our consultants completed a refresh of the qualitative assessment focussing on the issues raised by DNOs.

8.17. We continue to think that our approach is sound on the basis of the reasons we gave at draft determinations as described above.

Diversions

Decision and results

8.18. We made no changes to the approach at draft determinations in assessing diversion costs and no changes to our modelled costs. We accept the volumes as submitted by each DNO. Unit costs are calculated using eight-year RIIO-ED1 forecasts.

8.19. Our industry-level view of diversions costs is broadly in line with the forecast costs. The ten slow-track DNOs forecast £376m of diversion costs over the RIIO-ED1 period and our view of efficient costs is £375m.

Table 8.2: Diversions modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	27	30	26	29	3	10%
NPgN	24	23	24	23	-1	-3%
NPgY	32	33	32	34	1	5%
WMID	70	71	70	71	1	2%
EMID	68	67	68	67	-1	-2%
SWALES	29	32	29	32	3	11%
SWEST	61	61	61	61	0	-1%
LPN	31	29	31	29	-2	-7%
SPN	58	57	58	57	-1	-2%
EPN	111	106	111	106	-5	-5%
SPD	11	11	11	11	-1	-5%
SPMW	23	23	23	23	0	0%
SSEH	4	4	4	4	1	27%
SSES	55	60	55	59	4	7%
Total	605	607	604	606	3	0.4%
Total excl WPD	**376**	**376**	**376**	**375**	**-1**	**-0.2%**

Draft determinations

8.20. In our draft determinations we concluded that the breakdown of industry volumes for diversions was not sufficiently comparable across DNOs and we applied the volumes as submitted by each DNO. Run rate analysis of diversion volumes revealed that all

DNOs' forecasts were relatively stable due to difficulty in forecasting trends in diversionary activities. We excluded any efficiency benchmarking relating to volumes for this reason.

8.21. Efficient unit costs were taken as the industry median calculated by a simple cost/volume ratio using eight year RIIO-ED1 forecasts. Due to the project based nature of diversions work, the forecast data was viewed as more reliable than historical data. This industry median unit cost was applied to the forecast volumes. Data on diversions was collected at four different voltage levels (LV, HV, EHV and 132kV), and a median unit cost was calculated and applied for each.

Responses

8.22. Those DNOs who commented on diversions agreed with our approach and no issues were raised on it.

Reasons for our decision

8.23. We make no changes to our draft determinations approach as we believe it to be sound and no issues were raised.

Diversions – rail electrification

8.24. At draft determinations we did not include an ex ante allowance for slow-track companies as we considered that these costs are adequately dealt with through an uncertainty mechanism. Three DNOs and a supplier agreed with our proposal to give all DNOs an uncertainty mechanism for rail electrification. One DNO thinks we should not have a materiality threshold for this mechanism as no baseline allowances have been included in the draft determinations and the proposed efficiency test should ensure that only efficiently incurred costs are remunerated. We make no changes for final determinations as we believe a materiality threshold is appropriate. If costs do not meet the materiality threshold they are not sufficiently large to make a change to allowances. The efficiency incentive rate and WACC already make some allowance for risk and uncertainty to deal with the less significant level of uncertain costs.

Electricity Safety, Quality and Continuity Regulations (ESQCR)

8.25. ESQCR costs are broken down into seven methods for meeting ESQCR requirements; shrouding, diversions, reconductoring, rebuild, undergrounding, derogation and other. Costs in each of the seven categories are then split by four voltage levels (LV, HV, EHV and 132kV).

Decision and results

8.26. We removed the ratchet applied at draft determinations. We accept the submitted volumes and apply a median unit cost for each category using DPCR5 and RIIO-ED1 data.

8.27. We continued to allow business as usual safety clearance costs reported in the EQSCR table even though they should have been reported in the legal and safety table.

8.28. Six of the ten slow-track DNOs submitted ESQCR costs totalling £187m and our view is in line with this at £186m, a less than 1% reduction in total forecast costs.

Table 8.3: ESQCR modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	3	3	3	6	2	76%
NPgN						
NPgY						
WMID						
EMID						
SWALES						
SWEST	15	15	15	8	-8	-50%
LPN						
SPN	27	27	27	22	-5	-19%
EPN	45	44	45	35	-10	-22%
SPD	48	48	48	56	8	18%
SPMW	61	61	61	64	3	5%
SSEH	3	3	3	3	0	3%
SSES						
Total	202	201	202	194	-8	-4.1%
Total excl WPD	**187**	**186**	**187**	**186**	**-1**	**-0.3%**

Draft determinations

8.29. With regards to unit costs we calculated an industry median unit for each ESQCR method at each voltage level using 13 years of data (DPCR5 and RIIO-ED1). DNOs were given the minimum of submitted and Ofgem modelled costs. We did not make any adjustments to the submitted volumes due to the safety importance of ESQCR.

8.30. Where a DNO had completed the agreed ESQCR programme but reported the business as usual safety clearance costs in the ESQCR reporting table (rather than in legal and safety), we allowed these costs at draft determinations. This reflects the importance we placed on ensuring that DNOs operate safe networks.

Responses

8.31. There were no objections to our approach to assessing ESQCR costs, although one DNO noted that ESQCR business as usual costs should have been reported in the legal and safety table.

8.32. One DNO believed that ESQCR costs should be excluded from totex. This is discussed in Chapter 4.

Reasons for our decision

8.33. We remove the ratchet in our modelling for the reasons given in Chapter 3.

8.34. We confirmed the DNO's ESQCR programme volumes with HSE.

8.35. We keep using 13 years of data in our analysis, but exclude the DNOs' data where they have completed their ESQCR program in DPCR5, as they had different scope of works.

8.36. There were differences in how safety related costs were reported by DNOs with the same costs reported in different tables (legal and safety, ESQCR). We carried out sensitivity analysis on the costs and volumes of all safety-related activity to test if the differences in reporting affect the combined modelled costs. It did not have a material effect. Because of this and the importance we place on ensuring the DNOs operate safe networks, we accept the fact that some costs were reported in the wrong table and do not disallow costs on that basis.

Legal and Safety

8.37. Legal and safety costs are broken down into six categories; site security, asbestos management, safety climbing fixtures, fire protection, earthing upgrades and other. Site security at substations was further broken down by three voltage levels (HV, EHV and 132kV), and asbestos management was further broken down into two categories (substations and meter positions). Under the other category DNOs are free to suggest other legal and safety related activity.

Decision and results

8.38. We removed the ratchet in our assessment of legal and safety costs. This is in line with our decision to remove most ratchets, discussed in Chapter 3. We accepted the submitted volumes and apply a median unit cost at each voltage level using 13 years of data. We now exclude asbestos management from the benchmarking and continue to apply a qualitative adjustment to ENWL safety climbing costs.

8.39. The ten slow-track DNOs forecast they will spend £337m on legal and safety activity over the RIIO-ED1 period. This is an increase of £7m from draft determinations, explained by an increase in NPgY's costs following a reallocation of costs from CNI due to a change in CNI category 3 sites (see paragraph 8.93). We believe the efficient total cost to be £366m, £29m more than submitted. This is largely due to the removal of the ratchet.

Table 8.4: Legal and safety modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex[29]	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	40	29	40	38	-2	-5%
NPgN	24	18	24	23	-2	-7%
NPgY	51	42	57	52	-5	-9%
WMID	25	22	25	23	-3	-10%
EMID	26	22	26	23	-3	-13%
SWALES	11	11	11	11	0	0%
SWEST	21	21	21	21	0	0%
LPN	41	40	41	65	24	58%
SPN	34	32	35	44	9	27%
EPN	48	47	48	56	8	17%
SPD	25	23	25	23	-2	-6%
SPMW	36	36	36	39	3	9%
SSEH	5	4	5	4	-1	-19%
SSES	26	22	26	22	-4	-15%
Total	414	368	421	444	23	5.5%
Total excl WPD	**330**	**293**	**337**	**366**	**29**	**8.6%**

Draft determinations

8.40. We accepted the volumes as submitted. To assess unit costs for all categories except other legal and safety costs, we calculated a median unit cost at the most disaggregated level of reporting. This was based on 13 years of data. We gave the minimum of submitted and modelled costs. For the other category we undertook a qualitative assessment. We applied a positive adjustment to ENWL's safety climbing costs following a qualitative review of its justification.

Responses

8.41. Three key areas were raised with the legal and safety assessment. Two DNOs argued that median unit costs are inappropriate as it did not account for differences in the scope of works, with one noting specifically the scope of work relating to the removal of asbestos. Another noted that the low ground clearance which was included by some DNOs in this area should have been reallocated to ESQCR.

Reasons for our decision

8.42. We remove the ratchet in our assessment for the reasons in Chapter 3. We revisited the scope of works for the areas assessed under legal and safety and decided

[29] UKPN has included legal and safety costs related to link boxes. We have accepted the costs for the first two years of RIIO-ED1 as we explain in detail in Chapter 4.

to exclude asbestos management because of the significant variation in the related costs.

8.43. We acknowledge that there were reporting issues for legal and safety and ESQCR, as noted above in paragraph 8.36.

Quality of service

Decision, results and draft determinations approach

8.44. We made no changes from our draft determinations and did not specifically provide any ex ante allowances for QoS. However, in reviewing the case for other activities and company specific adjustments, we recognised that some projects have QoS benefits. This is true for LPN's central London case (Chapter 4) and SSEH's worst served customers (Chapter 9). Both DNOs have proposed improved CI and CML targets which we have accepted.

Responses

8.45. Three DNOs responded to our approach. Two largely agreed with the approach while one was disappointed at not receiving funding for tightening CML and CI targets.

8.46. This was one of the few areas that elicited responses from stakeholders other than DNOs. London First was concerned about the high utilisation of network, rising demand and incentives available to meet that future demand. It supported UKPN's proposals for early investment in the quality of supply in central London.

Reasons for our decision

8.47. We believe it is generally inappropriate to provide specific funding for QoS. DNOs receive financial incentives if they perform well against CI and CML targets under the Interruptions Incentives Scheme (IIS) and therefore should fund improvements on this basis.

8.48. However, we have taken the views of stakeholders into account in relation to Central London expenditure and worst served customers in the Highlands and Islands. We factor them into our assessment of efficient expenditure in the relevant cost activities.

Flood resilience

8.49. Flood resilience is broken down into several sections; flood mitigation schemes (fluvial and coastal) at HV, EHV, 132kV, and 275/400kV, flood mitigation schemes (pluvial), flooding site surveys (fluvial and coastal), and flooding site surveys (pluvial).

Decision and results

8.50. We continue to take a risk based approach to assessing flood resilience costs. We determine a risk delta based on calculating the risk of flooding at each substation before and after intervention. The delta gives credit to maintain the risk level at each substation, as well as risk reduction. We calculate a unit cost of each risk point reduced/maintained and apply that to the delta. The unit cost is taken as the lower of the DNO's own cost per risk point reduced/maintained and the industry lower quartile (LQ).

8.51. We correct for an error in our approach. The cost of each risk point is now calculated using both DPCR5 and RIIO-ED1 data. We used both data periods to calculate the risk points so it is correct to use both periods for costs.

8.52. Total submitted costs for flood resilience by the ten slow-track DNOs are £88m and our view is £85m, a difference of 3.7% (£3m).

Table 8.5: Flood mitigation modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	11	11	11	11	0	0%
NPgN	17	15	17	16	-1	-6%
NPgY	23	23	23	21	-2	-9%
WMID	1	1	1	1	0	0%
EMID	5	3	5	5	0	0%
SWALES	8	3	8	8	0	0%
SWEST	1	1	1	1	0	0%
LPN	4	4	4	4	0	0%
SPN	4	4	4	4	0	0%
EPN	8	8	8	8	0	0%
SPD	1	1	1	1	0	-2%
SPMW	1	1	1	1	0	0%
SSEH	1	1	1	1	0	-16%
SSES	20	20	20	20	0	0%
Total	103	94	103	100	-3	-3.2%
Total excl WPD	**88**	**86**	**88**	**85**	**-3**	**-3.7%**

Draft determinations

8.53. We assessed each category separately to give an industry median unit cost based on RIIO-ED1 data, with each DNO's unit cost determined by a simple division: RIIO-ED1 forecast costs/RIIO-ED1 forecast volumes.

8.54. We assessed the risk points at each substation for each flood mitigation scheme. We calculated the total risk on the network before and after investment. This was the flood likelihood at each substation (1 in 100, 1 in 200, or 1 in 1000) multiplied by the number of customers supplied by that substation. The flood likelihood after investment also gave credit where a DNO maintained the level of flood likelihood. We gave credit where DNOs provided protection up to the current unprotected level of risk. This was in line with the approach taken at DPCR5 and recognised that it may not be economic or feasible to protect to a higher level of risk. The difference between these risk levels was calculated to achieve a risk delta (ie total reduction in risk points).

8.55. We then took each DNO's submitted costs and divided this by the delta to calculate the cost per risk point reduced or maintained. For each DNO we applied the minimum of the DNO's own cost per change in risk point or the industry LQ cost per change in risk point. We chose to benchmark based on LQ (top 75% of costs) and not the stricter industry median. While we wanted to ensure costs were efficient, we also wanted to ensure that any reduction in costs did not put flood mitigation work at risk of not being completed. Equally, given the different flood mitigation strategies proposed by the DNOs we felt that to uplift those DNOs with a lower cost per risk point than the LQ would result in an inappropriately generous cost allowance. We have accepted the workload put forward by the DNOs.

Responses

8.56. Two DNOs agreed with our approach. One believed that there was a methodological flaw in our analysis. It suggested that the risk score improvements were based on a combination of schemes completed in DPCR5 and RIIO-ED1, whereas the allowances requested only relate to schemes in the RIIO period. It also said that the activity is a mix of fluvial/tidal and surface water flood defences which will have different cost risk benefit profiles and may be influencing the median, making the DPCR5 activity look the more efficient. It also suggested that there were inconsistencies in the way that improvements in flood risk are reported across DNOs.

Reasons for our decision

8.57. Following the concerns raised with our base model approach, we asked our engineering consultants to review each DNOs flood resilience programmes. This was to determine if we should make any qualitative adjustments to our base model.

8.58. Four DNOs (two DNO groups) received a reduction in their submitted costs and one of these groups raised issues with the assessment. A review of one group's costs revealed that the cost per site was very high compared to other DNOs, particularly its cost of survey and pre-mitigation. The consultants recommended a greater reduction than our model suggests. They recommended awarding the other DNOs the costs as per the base model.

8.59. We believe continuing with the approach at draft determinations is right. The majority of DNOs support this approach and the qualitative review is in line with the quantitative results.

BT21C[30]

Decision and results

8.60. We made no changes from the base model used for draft determinations approach. We accept the volumes submitted by DNOs and calculate an industry median unit cost using 13 years' of actual and forecast data.

8.61. We no longer make a qualitative adjustment to SPMW's modelled costs. This was an error at draft determinations. We continue to make a negative qualitative adjustment to SSE's modelled costs, as detailed below.

8.62. Six of the ten slow-track DNOs submitted RIIO-ED1 costs for BT21C totalling £80m. We do not believe these costs to be efficient and apply a £27m (33.2%) reduction to DNO forecast costs. The submitted costs are the same as draft determinations but the modelled costs are lower. This is due to the removal of SPMW's qualitative adjustment.

Table 8.6: BT21C modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL						
NPgN						
NPgY						
WMID	6	2	6	2	-3	-59%
EMID	9	3	9	2	-6	-72%
SWALES						
SWEST						
LPN			0	0	0	
SPN	16	10	16	10	-6	-37%
EPN	25	13	25	13	-11	-45%
SPD	5	4	5	4	-1	-27%
SPMW	28	35	28	20	-8	-28%
SSEH	2	2	2	2	0	0%
SSES	4	4	4	4	0	0%
Total	95	73	95	58	-36	-38.4%
Total excl WPD	**80**	**68**	**80**	**53**	**-27**	**-33.2%**

[30] BT21CN refers to the roll out of BT's next generation communications network which replaces Public Switched Telephone Network (PSTN) with a Digital Internet Protocol (IP). Whilst changing the communications protocol used on the existing network assets, it also accelerates the replacement of copper communications circuits with non-metallic optical fibre.

Draft determinations

8.63. We accepted the volumes of BT circuits submitted by each DNO. We were satisfied with the evidence provided (ie a list of all BT circuit reference numbers) that these volumes were justified. For our unit cost assessment, we calculated an industry median unit cost using 13 years of data. The unit costs included DPCR5 data where BT21C costs were classified as high value projects. The unit costs were then multiplied by the submitted volumes to set modelled costs.

8.64. We considered changing our volume driver following comments made by DNOs on the fast-track assessment. We asked for the detail on the length of overhead and underground pilot wires used to replace BT21C circuits, and detail on the type of solutions adopted and the justification for choosing those solutions. We did not have confidence in the data provided and therefore the number of BT circuits remained the volume metric.

8.65. We reviewed submitted data on the cost of different solutions to BT21C. We considered making a qualitative adjustment for those DNOs where an aggregate BT21C unit cost assessment could be penalising them unfairly (ie there are justifiable reasons for adopting more expensive solutions). The data received allowed us to complete a unit cost comparison by type of solution for only a limited number of solutions. Those DNOs with high aggregate unit costs (who therefore received a reduction) were also significantly more expensive for the comparable solutions types (eg microwave radio and fibre optic cable) than comparator DNOs. We concluded that this suggests cost inefficiencies across all BT21C solutions for those DNOs and it is therefore inappropriate to make a qualitative adjustment based on the cost of different solutions.

8.66. A positive qualitative adjustment was made to SPMW's modelled costs to account for greater volumes of BT21C circuits.[31] We also made a negative qualitative adjustment to SSE's modelled costs. The solution adopted by SSE is significantly less expensive than that of other DNOs and the model uplifts the submitted costs by 460-480%. We did not believe this was reasonable. There was insufficient evidence to make any qualitative adjustments for other DNOs.

Responses

8.67. One DNO argued that using the number of circuits as the volume metric disadvantages DNOs with longer routes and route length is a more accurate representation of the work required.

8.68. One DNO highlighted categorisation issues in the allocation of costs between BT21C and operational IT&T costs, particularly where companies are in different phases of their BT21C projects. It noted that the costs of replacing assets with relatively short asset lives which were installed as part of the BT21C project in DPCR5 or early in RIIO-

[31] This was an error at draft determinations as explained in paragraph 8.68.

ED1 will begin to show up in the operational IT&T costs towards the end of the RIIO-ED1 period. We consider this issue in our qualitative assessment of operational IT&T costs above.

Reasons for our decision

8.69. As noted we made no changes to the approach we took at draft determinations other than to remove a positive qualitative adjustment for SPMW in the disaggregated modelling.

8.70. The SPMW special case for BT21C was based on the fact that the interconnected network will require more circuits to be replaced than for traditional radial networks. We agree with this, but as our disaggregated model accepts the volumes forecast by DNOs, the special factor is accounted for in our base model. Therefore, we do not need to make any further volume based qualitative adjustment.

8.71. We do not believe that route length is necessarily a better volume metric than number of circuits.

8.72. It is evident that the adopted solutions as well as the format in which all the DNOs report cost and volumes vary significantly and we are not in position to construct better unit cost comparators. Solutions proposed by DNOs vary significantly which makes direct comparison between DNOs difficult. Therefore we took a more holistic approach to considering whether to make qualitative adjustments to any DNO following the results of our base model.

8.73. We considered two key issues: the overall cost of the package of solutions adopted by each DNO and the comparative unit costs of the same solutions across DNOs.

8.74. The DNO that raised the issue of using route length as a volume metric typically adopted the most expensive BT21C solution. The justification for doing so was not sufficient for us to make a positive qualitative adjustment. It planned to implement predominately a fibre solution. This is the most expensive option and adopting it is in contrast with the strategy of majority of the DNOs. The majority of other DNOs are proposing to use short lengths of fibre or pilot cable only where there are more specific requirements, eg reliability or bandwidth.

8.75. At the same time, we recognised the cost per km of fibre optic cable of this DNO is lower than another DNO (the comparative assessment was only possible for two DNOs). This is expected for longer circuits due to an element of fixed costs.

8.76. Overall, we did not make any qualitative adjustments as the DNO seeking that adjustment has not sufficiently justified the use of more expensive solutions.

Losses and other environmental

8.77. Total environmental costs comprise costs related to schemes to reduce losses and eight other environmental areas as follows:

- visual amenity
- oil pollution mitigation scheme - cables
- oil pollution mitigation scheme - operational sites
- oil pollution mitigation scheme - non-operational sites
- SF6 emitted mitigation schemes
- noise pollution
- contaminated land clean up
- environmental civil sanction.

8.78. For losses, it is important to note that the costs reported in this section and the adjustments described in Table 8.9 refer only to CV12 costs.[32] The benefits of loss reduction measures are greater than reported in CV12. For instance, under general asset replacement cycles DNOs are replacing old transformers with low loss transformers and this is captured under asset replacement costs and not under environmental costs.

8.79. Where DNOs appropriately justified accelerating asset replacement or higher unit costs to deliver incremental losses benefits, we have allowed the associated higher volumes or unit costs. Low-loss transformer volumes have been allowed for ENWL and SPEN. Positive unit cost adjustments were made to SSEPD's transformer replacement costs and to NPg's LV and HV cable costs.

Decision and results

8.80. We made two key changes to the environmental cost assessment. First, we removed the ratchet. We now use the modelled costs (and not lower of modelled and submitted) for losses, and six of the other environmental categories - visual amenity, oil pollution mitigation schemes (cables, operational sites and non-operational sites), noise pollution and contaminated land clean up. Second, we only apply median unit costs where there are a sufficient number of data points.

[32] These are the costs reported in the CV12 table in the business plan data tables (BPDTs) submitted by the DNOs. CV12 losses refer to the replacement of assets for which that replacement was driven mainly for environmental reasons (ie losses reduction). Asset replacement reported elsewhere (in CV3) may also have environmental benefits but the primary reason for replacement is not environmental-related.

8.81. For those activities where the assessment involves unit cost analysis, the unit cost used for each falls into one of three categories as follows:

- Expert view: losses
- Median: oil pollution mitigation schemes – operational sites, oil pollution mitigation schemes – non-operational sites, noise pollution and contaminated land clean up
- DNO own (lower of DPCR5 and RIIO-ED1): visual amenity, oil pollution mitigation schemes – cables and environmental civil sanctions

8.82. For environmental civil sanction we made no changes. It remains subject to the qualitative assessment at draft determinations. The changes for each activity are summarised in Table 8.7.

Table 8.7: Changes from draft to final determinations for losses and other environmental

Environmental category	Draft determinations approach	Final determinations approach
Losses reduction schemes	Volumes allowed where appropriately justified. Unit costs: the minimum of submitted or modelled where modelled costs use the expert view of the relevant asset type. This was overlaid by a qualitative assessment where unit costs are allowed when they are appropriately justified by losses reduction and are above minimum legal requirements. For ENWL, a qualitative adjustment was made to allow the 'theft in conveyance' prior to benchmarking. For SSES the expenditure on losses was not appropriately justified and therefore not allowed.	As draft determinations except unit costs now set at the expert view.
Visual amenity (excluding AONB)	Volumes allowed where justified. Unit costs: the minimum of submitted or modelled where modelled costs uses the expert view of underground cable costs.	As draft determinations except unit costs are DNOs' own (but lower of DPCR5 and RIIO-ED1).
Oil Pollution Mitigation Scheme - Cables	Volumes allowed where justified. Unit costs: the minimum of submitted or modelled where modelled costs use the industry median based on 13 years' of DNO's data. For contaminated land clean up an adjustment was made to allow ENWL what it asked for, due to the strong justification of the schemes.	As draft determinations except unit costs are DNOs' own (but lower of DPCR5 and RIIO-ED1).
Oil Pollution Mitigation Scheme - Operational Sites		As draft determinations except unit costs now modelled median.
Oil Pollution Mitigation Scheme - Non Operational Sites		As draft determinations except unit costs now modelled median.
Noise Pollution		As draft determinations except unit costs now modelled median.

Contaminated Land Clean Up		As draft determinations except unit costs now modelled median.
SF6 Emitted Mitigation Schemes	No costs submitted.	No costs submitted.
Environmental Civil Sanction	Qualitative review and costs accepted as submitted for all DNOs.	As draft determinations.

8.83. The ten slow-track DNOs forecast they would spend £102m on environmental activity in RIIO-ED1; we assessed the efficient level of expenditure to be £103m. This is £31m more than at draft determinations and is largely due to the removal of the ratchet.

Table 8.8: Environmental modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	16	13	16	13	-3	-18%
NPgN	1	1	1	2	1	159%
NPgY	1	1	1	4	3	307%
WMID	4	4	4	5	1	16%
EMID	5	5	5	6	1	20%
SWALES	2	2	2	3	0	17%
SWEST	2	2	2	3	1	26%
LPN	4	3	4	6	2	51%
SPN	3	3	5	9	4	77%
EPN	10	9	12	13	1	12%
SPD	18	16	18	17	-1	-8%
SPMW	16	14	16	15	-1	-8%
SSEH	10	3	10	4	-6	-58%
SSES	18	10	18	19	1	3%
Total	111	85	115	118	3	3.0%
Total excl WPD	**98**	**72**	**102**	**103**	**1**	**0.8%**

Draft determinations

Losses

8.84. We undertook a qualitative assessment based on the DNOs' losses strategies at fast-track, which we reviewed ahead of draft determinations. While we focused on the narratives, we also analysed some of the CBAs provided. Our assessment concluded that most companies had addressed most or all of the key areas in our strategy decision, but we highlighted the need for more robust CBA justification in a number of cases. We then looked in more detail at the measures proposed by each DNO, with their associated costs and benefits. We assessed the proposed measures to reduce losses and explored these through questions to the companies. We asked DNOs to identify all losses-reducing activities across their strategies and sought specific quantification of proposals where proposed measures and costs were not specified. We have made use of DNO narratives, supporting information provided during the assessment process and CBAs.

8.85. We also sought confirmation of how proposed measures, particularly low loss transformers, compared with legal minimum requirements for existing or impending EU legislation related to asset specifications.

Other environmental

8.86. At draft determinations the overarching approach for environmental activity was to allow the submitted volumes of work where a qualitative assessment supported it, and to assess whether the costs are reasonable.

8.87. Our quantitative modelling of unit costs was overlaid and sense checked with a qualitative assessment bespoke to each environmental category. Where we set industry median unit costs, we used 13 years of actual and forecast data. Many of the categories had limited data and so a longer time period provided information which is reflective of RIIO-ED1 as well as historical data. We chose 13 years for all categories to ensure consistency across the environmental assessment. We applied the minimum of modelled and submitted as we felt that while the qualitative assessment gave us confidence to allow forecast costs in some cases (and to allow volumes in others) it did not provide justification to allow more than the DNOs requested.

8.88. Table 8.8 above summarises our draft assessment for each of the eight categories.

Responses

8.89. The majority of DNO groups that responded agreed with the approach we took at draft determinations.

8.90. One DNO argued that we should not use median unit costs when the sample size is small. It also considered that the approach does not consider company specific factors such as geographical location and meteorological conditions that increase costs and different scope of works.

Reasons for our decision

8.91. We remove the ratchet in our modelling and we now only apply median unit costs where there are a sufficient number of data points. Where there are limited data points, we use the DNO’s own unit costs but take these as the lower of its DPCR5 and RIIO-ED1 unit costs. There was no clear evidence presented that would justify differences in units costs between DPCR5 and RIIO-ED1. We accept all the volumes submitted by DNOs in each category following a qualitative assessment that concluded they were justified.

8.92. We considered the impact of geographical location and meteorological conditions in this area with our engineering consultants. We do not believe that persuasive evidence has been submitted to substantiate such claims. For example, we believe any differences in contractor costs would be covered under regional labour adjustments.

Critical national infrastructure (CNI)

Decision and results

8.93. Following confirmation from DECC of the sites across the distribution network which are classified as Category 3 or higher CNI, we allow the submitted costs of £7m for these sites. Our allowed costs have changed from draft determinations due to the reclassification of some sites, which were formerly Category 3 or above, to Category 2 or lower by DECC.

Table 8.9: CNI modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL						
NPgN						
NPgY	12	12	1	1	0	0%
WMID						
EMID						
SWALES						
SWEST						
LPN	0	0	1	1	0	0%
SPN	0	0	1	1	0	0%
EPN	0	0	2	2	0	0%
SPD						
SPMW	2	2	2	2	0	0%
SSEH						
SSES						
Total	14	14	7	7	0	0.0%
Total excl WPD	14	14	7	7	0	0.0%

Draft determinations

8.94. At draft determinations we allowed all costs for sites which DECC had confirmed were classified as Category 3 CNI. As confirmed by DECC all sites classified as Category 3 CNI or above are eligible for ex ante funding in accordance with the Physical Security Upgrade Programme (PSUP).

Responses

8.95. One DNO said that as discussions with DECC on CNI classifications was ongoing, should requirements at affected sites materially change, they would need to be adequately covered by a re-opener mechanism.

Reasons for our decision

8.96. Our approach is the same as at draft determinations in that we allow all costs for sites classified as Category 3 and above. The list of sites classified as Category 3 and above, and therefore eligible for ex ante funding in accordance with the Physical Security Upgrade Programme (PSUP) has changed however. As a consequence, five DNOs incur costs.

8.97. Our approach to funding for CNI sites is consistent with DECC's position. Sites which are subsequently reclassified as Category 3 after the commencement of RIIO-ED1 may be eligible for funding through a re-opener mechanism.

Black start

8.98. Black start is broken down into two main categories: black start resilience (BSR) at substations and BSR - securing of existing telecommunications infrastructure. These two categories are broken down further. BSR at substations by voltage (EHV and 132kV) and by battery type (SCADA or Protection). BSR – securing of existing telecommunications infrastructure is broken down by landlines and internal telephony, mobile and voice communications, and SCADA infrastructure. This results in seven sub-categories of black start, all of which were subject to a separate cost and volume assessment.

Decision and results

8.99. We made no changes to our assessment of black start costs for final determinations. For each sub-category we apply industry median unit costs using eight years of RIIO-ED1 data.[33] The volumes of batteries are based on the number of unprotected primary substations multiplied by the industry average number of batteries per substation. The submitted volumes for the internal telephony, mobile and voice communications and SCADA infrastructure are accepted.

8.100. We made no qualitative adjustment to our base model costs for those DNOs that use generators rather than batteries to provide BSR.

8.101. The ten slow-track DNOs submitted £41m for blackstart resilience. Our modelled costs are £39m. Submitted costs changed from £44m at draft determinations, explained by SPMW's reduction.

[33] At draft determinations the model took the lower of the DNOs DPCR5 and RIIO-ED1 then applied an industry median. This was an error that has been corrected. The model applies the industry median of the RIIO-ED1 costs. The effect is small as very few DNOs reported black start costs in DPCR5.

Table 8.10: Black start modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	7	8	7	8	1	9%
NPgN	4	3	4	3	-1	-34%
NPgY	6	5	6	5	-1	-24%
WMID	3	4	3	4	0	11%
EMID	7	8	7	8	2	27%
SWALES	2	3	2	3	1	57%
SWEST	4	4	4	4	1	23%
LPN	2	2	2	2	0	-7%
SPN	3	4	3	4	1	24%
EPN	4	6	5	6	1	29%
SPD	2	2	2	2	0	10%
SPMW	7	4	4	4	0	3%
SSEH	4	4	4	4	0	-10%
SSES	2	1	2	1	-1	-42%
Total	59	56	56	58	2	4.4%
Total excl WPD	**44**	**38**	**41**	**39**	**-1**	**-3.6%**

Draft determinations

8.102. For all areas, the industry median was taken as the unit cost using eight years of RIIO-ED1 data, as only forecast data was available. This was multiplied by submitted volumes to calculate the unit cost adjustment for each DNO.

8.103. As noted, the volumes of batteries were based on the number of unprotected primary substations multiplied by the industry average number of batteries per substation. The volumes for the internal telephony, mobile and voice communications and SCADA infrastructure could be no greater than the number of unprotected primary substations.

Responses

8.104. Three DNOs responded on our approach to assessing black start costs. One submitted costs based on installing generators rather than batteries at 132kV substations. It believed that lower cost, batter-based solutions will provide inferior resilience to black start events.

8.105. Another said we had not made like-for-like comparisons in its unit cost assessment of black start costs.

8.106. The third argued that the costs of all batteries including those for protection, BT21C and black start, should be assessed as a whole.

Reasons for our decision

8.107. Following an engineering review we do not believe the generator solution at 132kV substations put forward is justified and believe that battery solutions provide the necessary resilience. This is supported by other DNOs. No other DNO group is proposing a generator solution at 132kV substations.[34]

8.108. We disagree that we have not make like-for-like comparisons in our unit cost assessment. Our cost assessment is conducted at the sub-category level and an industry median unit cost was applied for each. There was no compelling evidence submitted by any DNO to suggest that its unit costs should differ in meeting the requirements of black start resilience.

8.109. Finally, we are making changes to the Regulatory Instructions and Guidance (RIGs) in RIIO-ED1 to ensure that we consider the costs of all batteries collectively.

Rising and lateral mains (RLMs)

Decision and results

8.110. We made no changes to our approach at draft determinations and our results have not changed. Submitted volumes for RLM for each DNO are accepted and unit costs are based on RIIO-ED1 data using customer numbers as the cost driver.

8.111. Our modelled costs are largely in line with DNO forecast costs.

[34] SPEN was permitted to resubmit its BPDT following our decision that battery solutions meet the requirements for black start resilience.

Table 8.11: RLM modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	15	15	15	15	0	0%
NPgN	3	3	3	3	0	0%
NPgY	4	4	4	4	0	0%
WMID						
EMID						
SWALES						
SWEST						
LPN			0	0	0	
SPN	16	16	16	16	0	0%
EPN	10	9	10	9	0	-4%
SPD	81	81	81	81	0	0%
SPMW	39	39	39	39	0	0%
SSEH	3	3	3	3	0	0%
SSES	7	7	7	7	0	0%
Total	178	177	178	177	0	-0.2%
Total excl WPD	**178**	**177**	**178**	**177**	**0**	**-0.2%**

Draft determinations

8.112. Following a qualitative assessment of volumes and a review of DNO run rates, the submitted volumes for RLM for each DNO were accepted. We accepted that the volumes do not lend themselves to benchmarking, as different DNOs will justifiably need to do more RLM work than others and many of the factors that drive the workload are outside the DNOs' control. We made no volume adjustments.

8.113. We calculated the unit costs based on RIIO-ED1 data using customer numbers as the cost driver.

Responses

8.114. Two DNOs explicitly agreed with this approach. No additional comments or objections were received.

Reasons for our decision

8.115. We make no changes to our approach as we believe our approach at draft determinations was sound and no objections were raised with it.

Improved resilience

Decision and results

8.116. SSEH requested an ex ante allowance to improve resilience for worst served customers (WSC). Our consultants compared costs of similar projects that have been carried out in the past, and alongside them we reached our efficient view of these costs. From the £25m submitted, we applied a £7m (27%) reduction for these WSC schemes as shown in Table 8.13.

Table 8.12: WSC adjustments

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
SSEH	25	12	25	18	-7	-27%

8.117. We expect SSEH to deliver the same level of benefits, in terms of CI and CML reductions, as it has identified in its business plans and the related CBAs, for our efficient view of costs.

Draft determinations approach

8.118. SSEH requested an ex ante allowance to improve resilience for worst served customers (WSC). This was not submitted in the fast-track business plan. It submitted six CBAs to justify its proposal. We asked our economic consultants (CEPA) to review the CBAs and related schemes. CEPA's view was that the benefits did not justify the costs. We then sought the views of our technical consultants (DNV GL) to review the schemes. Based on these reviews and our disaggregated analysis, we further reviewed the submitted breakdown costs for each scheme.

8.119. Using our expert view unit costs and comparing costs of similar projects that have been carried out in the past, the details of which came from a database of projects held by the consultants, we reached our efficient view of costs. From the £25m submitted, we allowed £13m, £12m (51%) less than submitted.

Responses

8.120. SSE questioned the use of the expert view unit costs for assessing WSC schemes as the schemes would require high cost materials. They provided additional information and cost breakdowns to support this.

Reasons for our decision

8.121. We assessed all the additional information provided by SSE together with our technical consultants. Because of the remote location and the technical difficulties in construction, higher unit costs are justified for the WSC schemes.

Summary of non-core cost results

8.122. In total, the ten slow-track DNOs estimated that they will spend £1,785m on non-core related activities in RIIO-ED1, a £1m decrease from draft determinations. Our assessments of the individual activities suggest this should be £1,756m, £29m (1.6%) lower than DNO forecast costs.

8.123. Our modelled costs increase by £97m from draft determinations. With LPN gaining most (£34m) followed by ENWL, SPN and SSES (all £14m). SPMW's modelled costs fall by £13m, explained largely by the removal of the BT21C qualitative adjustment.

Table 8.13: Non-core modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	184	154	183	168	-15	-8%
NPgN	97	86	97	94	-3	-4%
NPgY	172	162	167	162	-4	-3%
WMID	134	129	134	131	-3	-2%
EMID	145	134	145	138	-7	-5%
SWALES	75	73	75	78	3	4%
SWEST	129	127	129	122	-8	-6%
LPN	131	117	132	151	20	15%
SPN	199	185	202	199	-3	-2%
EPN	307	287	311	294	-17	-6%
SPD	211	207	211	217	5	3%
SPMW	247	254	243	241	-2	-1%
SSEH	75	54	75	61	-14	-18%
SSES	163	155	163	169	6	4%
Total	2,269	2,121	2,268	2,225	-43	-1.9%
Total excl WPD	**1,785**	**1,659**	**1,785**	**1,756**	**-29**	**-1.6%**

9. Network Operating Costs

Chapter summary

Our approach to assessing network operating costs (NOCs). It reviews our draft determinations approach, the issues raised during the consultation, and describes our final determinations assessment and the results of this. It also describes our method for setting ex ante allowances for smart meter costs and for improved resilience.

Overview

9.1. Network operating costs (NOCs) include the following activity areas:

- troublecall
- occurrences not incentivised (ONIs)
- severe weather 1 in 20 events
- inspections and maintenance
- tree cutting
- NOCs other.

9.2. We have taken a range of different approaches to assess these individual activity areas.

9.3. For the draft determinations we used regression analysis in our assessment of tree cutting (ENATS 43-8 activity), troublecall and ONIs.

9.4. The following NOCs activities were not regressed for the draft determinations assessment; severe weather 1 in 20 events, inspections and maintenance, tree cutting (ETR 132 activity), and NOCs other.

Troublecall and ONIs

Decision and Results

9.5. We make no changes to our draft determinations approach for troublecall with the exception of our unit costs assessment for submarine cables. Due to the variability in unit costs for submarines cable, we are now allowing the DNOs their own unit costs. For the other areas of troublecall we continue to assess volumes and unit cost in the same way as for draft determinations.

9.6. For the occurrences not incentivised (ONIs) volume assessment, we make a slight change to our methodology to mirror the volume assessment for troublecall. Where there are large variations in unit costs for certain categories, we make further qualitative adjustments for these categories.

9.7. For both troublecall and ONIs the assessment is bespoke for each voltage level and fault category, as detailed in Table 9.1.

9.8. The ten slow-track DNOs collectively forecast £1,572m for troublecall and our modelled costs are £1,640m, an increase of £68m (4.3%).

9.9. Our modelled costs increase by £84m from draft to final determinations. This increase is due to corrections to our qualitative adjustments and in allowing subsea cable costs for SSEH.

9.10. The ten slow-track DNOs collectively forecast £427m for ONIs and our modelled costs are largely in line with that at £429m. Our modelled costs are £25m more than at draft determinations.

Table 9.1: Troublecall modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	162	167	162	167	5	3%
NPgN	150	129	150	130	-20	-13%
NPgY	226	219	226	221	-5	-2%
WMID	175	157	175	154	-20	-12%
EMID	217	166	217	177	-40	-18%
SWALES	80	84	80	87	7	9%
SWEST	151	145	151	154	3	2%
LPN	138	127	138	145	7	5%
SPN	151	142	151	150	-1	-1%
EPN	227	226	227	236	9	4%
SPD	140	144	140	150	10	7%
SPMW	115	122	115	123	7	6%
SSEH	98	87	98	103	4	4%
SSES	164	192	164	216	52	32%
Total	2195	2108	2195	2213	18	0.8%
Total excl WPD	**1572**	**1556**	**1572**	**1640**	**68**	**4.3%**

Table 9.2: ONIs modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	36	27	36	32	-4	-11%
NPgN	35	27	35	32	-2	-7%
NPgY	72	63	72	67	-5	-7%
WMID	31	30	31	30	-1	-3%
EMID	22	22	22	22	0	2%
SWALES	14	11	14	11	-3	-21%
SWEST	20	16	20	16	-4	-21%
LPN	41	41	41	40	-2	-5%
SPN	38	41	38	38	0	1%
EPN	67	66	67	65	-2	-3%
SPD	35	34	35	43	8	22%
SPMW	38	35	38	42	4	11%
SSEH	10	9	10	9	-1	-10%
SSES	55	61	55	61	6	11%
Total	515	484	515	509	-6	-1.2%
Total excl WPD	**427**	**404**	**427**	**429**	**2**	**0.4%**

Draft determinations approach

9.11. A range of different approaches were used for the analysis of troublecall and ONIs.

9.12. Table 9.3 summarises our approach for each voltage level and fault type, both at draft determinations and final determinations, and our rationale for the final determinations approach.

Table 9.3: Summary of cost assessment approach for troublecall and ONIs

Voltage level and fault category	Summary of draft determinations	Revised approach for final determinations	Rationale for change
LV/HV Overhead faults	Regressed using LV/HV overhead line length.	No change in our methodology from draft determinations.	
LV/HV plant and equipment	Assessed using ratio benchmarking analysis. Assessment uses industry median unit costs. Efficient volumes assessed taking the lower of DPCR5 actual or RIIO-ED1 submitted fault rates.	No change in our methodology from draft determinations.	

LV underground faults	Industry median unit costs being used. We have also considered the length of underground cable replaced and have made a qualitative adjustment to take account of this. Efficient volumes assessed taking the lower of DPCR5 actual or RIIO-ED1 submitted.	No change in our methodology from draft determinations.	
HV underground faults	Unit costs for faults assessed using MEAV. Efficient volumes assessed taking the lower of DPCR5 actual or RIIO-ED1 submitted.	No change in our methodology from draft determinations. An error in our Draft determinations Business Plan Expenditure document has been corrected. Fault unit costs are assessed using industry median unit costs instead of MEAV.	
LV/HV switching faults	Efficient volumes assessed taking the lower of DPCR5 actual or RIIO-ED1 submitted fault rates. Unit costs for these fault types assessed using industry median.	No change in our methodology from draft determinations.	
Submarine cable faults		No change from draft determinations for volume assessment. There is a change to our unit cost assessment. We are now awarding DNOs their own unit costs.	A DNO explained that using the industry median unit cost is inappropriate because the work it undertakes to repair a fault is considerably more costly than that of other DNOs.
EHV and 132kV faults		No change in our methodology from draft determinations.	
Pressure assisted cables		No change in our methodology from draft determinations.	

ONIs	Assessed using ratio benchmarking analysis. We have assessed volumes and unit costs at a disaggregated level. Efficient volumes were assessed taking the lower of DPCR5 actual or RIIO-ED1 submitted.	Slight change in our methodology from draft determinations. Our assessment of ONIs volumes mirrors that of troublecall. For unit cost assessment we have made a number of qualitative adjustments.	A DNO highlighted the inconsistency in ONIs volume assessment to that of troublecall. For our unit cost assessment, DNOs highlighted the wide variation in costs across the industry.

Qualitative Adjustments

9.13. For LV and HV underground faults there is a definitional boundary between asset replacement and troublecall. Those DNOs that undertake proactive replacement of these assets enter the replacement costs in the relevant asset replacement table of the business plan data templates (BPDTs). Those that adopt a reactive replacement strategy enter these costs as troublecall costs.[35] The four WPD DNOs adopt a reactive replacement strategy. As such the cost per fault is typically higher for the WPD DNOs as the length of cable used to repair each fault is greater.

9.14. To account for this in our troublecall analysis we made an adjustment to WPD for LV underground faults. We calculated the average length of cable installed to repair a fault for the other ten DNOs. We multiplied this by WPD's fault rates to determine the number of faults that should be assessed for WPD under troublecall. The troublecall benchmark unit costs were then applied to these faults. For the additional length of cable that WPD install when repairing a fault, we applied the relevant unit cost from the asset replacement model. This approach did not adversely affect the calculation of efficient volumes for the other DNOs in the asset replacement model as these were calculated using the age-based model rather than run rate analysis.

9.15. For UKPN and SPD LV underground consac cable faults, we made a qualitative adjustment to our modelled volumes where our analysis indicated inconsistency in DNOs' data reporting.

9.16. For SSEPD we made a qualitative adjustment for the improvement in fault rates used by SSEPD to justify its CONSAC cable replacement programme. SSEPD's LV switching volumes were comparatively high and we used our implied fault rate (the minimum of DNO volumes and the industry median fault volume), as the basis for our qualitative adjustment.

[35] DNOs reporting this as asset replacement would place costs and volumes in the CV3 table in the BPDTs but those reporting in troublecall would place the costs in CV15a.

9.17. We also made a qualitative adjustment to SSEPD’s HV overhead line volumes to reflect its asset replacement allowance for the undergrounding of 500km of overhead lines affected by trees.

9.18. For ONIs, we made a number of qualitative adjustments where volumes were high. This applied to the following DNOs: NPgN, SPD, SPMW and EPN. We based our qualitative analysis on the average historical run rates and the output of our customer number analysis.

Responses

9.19. Two DNOs felt there were significant activity definition and classification issues for ONIs. Another DNO highlighted that there are inconsistencies between the methodology we used to asses troublecall and the methodology for ONIs. It felt that there were inconsistencies in our unit costs assessment for certain categories of ONIs.

9.20. One DNO did not agree with our unit costs assessment for some areas of troublecall. It stated that our assessment failed to take into account either its reactive asset replacement strategy or the mix of asset types across DNOs. It claimed other DNOs’ cost forecasts for HV plant and equipment were implausible and that these forecasts distorted our unit cost assessment.

9.21. One DNO queried our unit cost assessment for subsea cables. Its view was that using the industry median cost is not appropriate because the work it undertakes to repair a fault is considerably more costly than other DNOs.

9.22. At the bilateral meetings one DNO highlighted a number of its concerns for the troublecall assessment. For 132kV and EHV volume assessment it felt our approach was inconsistent with the IIS target setting methodology, where we used 10 year average volumes. It also questioned the qualitative adjustments we had made to the volumes for LV CONSAC and pressure assisted underground cables. Finally, this DNO identified a number of apparent errors in our calculation of the qualitative adjustments.

Reasons for our decision

9.23. We have refined our methodology for assessing ONIs. For volumes, we use the same methodology as troublecall, ie total volumes are set as the lower of DPCR5 actuals or RIIO-ED1 volumes. We remove the qualitative volume adjustments that were derived using analysis of customer numbers. For SMPW we make a qualitative adjustment based on its regional case. For our unit cost assessment, we assess each of the subcategories separately and make a number of qualitative adjustments where we identified a wide range of unit costs across the industry.

9.24. We make a number of qualitative adjustments to fault volumes where DNOs are reporting excessively high fault volumes or are forecasting significantly higher fault rates on a small number of network assets. Following the advice of our consultants we remove the qualitative volume adjustment for LV CONSAC for a DNO. We retain the other qualitative adjustment that we made in draft determinations. We recognise that there were some formula errors in our qualitative adjustments and have corrected these.

9.25. For WPD's LV UG cable qualitative adjustment we make one further minor change to our methodology. We now use the historical industry median length of cable installed as the benchmark length of cable required to repair an LV cable fault.

9.26. Although one DNO felt that our unit costs assessment for number of troublecall areas was inappropriate, we think our overall approach at draft determinations was sound and continue to use it for final determinations.

9.27. We continue to use median unit costs on the basis it reflects the average scope of work across the industry and excludes the outliers. We apply a consistent approach throughout the disaggregated costs assessment. Where submitted costs are above the industry median, we disallow the difference. Where they are below the industry median we uplift DNOs' submitted costs. The DNO that disagreed with our approach did not sufficiently justify why its scope of work for each area of troublecall is different to that of the other DNOs.

9.28. We refine the unit cost assessment for subsea cables to award DNOs their own unit costs. One DNO group thought it was unfair to benchmark its costs to that of the other DNOs because the work it undertakes is to repair faults is significantly more costly. We accept this and change our methodology accordingly.

9.29. Our methodology for the assessment of 132kV and EHV fault volumes does not change from draft determinations. Volumes were assessed as the lower of the annual average of DPCR5 actuals or the RIIO-ED1 annual average. We reviewed one DNO's suggestion of using the IIS ten year average volumes (2005-06 to 2014-15). For most DNOs the historical ten year annual average volumes are higher than both the DPCR5 actual and RIIO-ED1 submitted volumes. We do not believe it is reasonable to use volumes that do not accurately reflect recent actuals or expected future volumes.

Tree Cutting (ENATS 43-8)

Decision and results

9.30. For tree cutting, ENATS 43-8 activity we make no changes to the draft determinations approach. We continue to apply regression analysis to ENATs 43-8 activity.

9.31. We asked our consultants to give us their view on some of the responses from DNOs and the supporting evidence submitted.

9.32. Over the RIIO-ED1 period the DNOs are forecasting to spend on average 25% less on ENATS 43-8 activity per annum than in DPCR5.

9.33. Table 9.4 shows that the ten slow-track DNOs submitted £625m in tree cutting costs for RIIO-ED1 and our view of efficient costs is slightly lower at £621m. No changes are made to the modelled costs for ENATS 43-8. The table also includes the costs of ETR 132 activity.

9.34. We retain our approach from draft determinations for assessing ETR 132 activity, with one change. We remove the ratchet which limited DNOs to either the lower of its submitted or our modelled costs, as discussed in Chapter 3. We have decided to exclude SP from our assessment, as well as NPg, due to SP's different approach to reporting costs and volumes

9.35. The ten slow-track DNOs submitted £70m in costs for ETR 132 activity and we allow £79m, an increase of £9m (12.9%) . These results are in line with the fact that DNO forecasts for RIIO-ED1 include efficiencies compared with their historical costs for ETR 132 activity.

Table 9.4: Tree cutting modelled costs (2012-13 prices)*

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	28	37	28	40	11	41%
NPgN	32	34	32	34	3	9%
NPgY	42	39	42	39	-3	-8%
WMID	61	64	61	65	3	5%
EMID	48	49	48	50	2	5%
SWALES	59	53	59	54	-5	-9%
SWEST	83	88	83	89	6	8%
LPN	0	0	0	0	0	0%
SPN	66	59	66	59	-6	-10%
EPN	127	135	127	136	9	7%
SPD	62	56	62	56	-7	-11%
SPMW	91	94	91	94	4	4%
SSEH	53	64	53	67	14	26%
SSES	125	93	125	95	-29	-24%
Total	876	866	876	878	2	0.2%
Total excl WPD	**625**	**612**	**625**	**621**	**-5**	**-0.7%**

*The results table includes ETR 132 activity.

Draft determinations approach

9.36. For ENATS 43-8 activity we applied regression analysis. We used spans cut and spans inspected as the drivers for the regression. We applied a scaling adjustment but did not apply a workload adjustment. The time period used for the regression was the eight years of RIIO-ED1.

9.37. For ETR 132 activity we performed a unit cost assessment using the industry median unit cost as a benchmark. NPg was excluded from assessment due to its significantly different approach to reporting costs and volumes.

Responses

9.38. One DNO commented that tree-cutting activity volumes could be a reliable cost driver only if coupled with a qualitative assessment of the appropriateness of company forecast volumes. This DNO felt that as most companies are forecasting flat year-on-year volumes through RIIO-ED1, which are in contrast to the actual reported volumes during DPCR5, any distortions are likely to be small.

9.39. One DNO disagreed with the use of only forecast costs and volumes for the RIIO-ED1 period in the regression analysis. It felt that this was inconsistent with Ofgem's approach to regressions elsewhere and that it does not take into account historical efficiencies.

9.40. Another DNO felt that our assessment should take account of the impact of growth rates on the cost of tree cutting per span. It felt that growth rates were a reliable indicator of regional differences between DNOs and should be used as a multiplier on each DNO's median unit costs.

9.41. Only two DNOs commented specifically on our assessment of ETR 132 activity. Both DNOs agreed with our draft determinations approach. One DNO commented that due to the necessary exclusion of some DNOs from assessment, Ofgem needed to gather more information on the range of approaches to risk reduction taken.

Reasons for our decision

9.42. For ENATS 43-8 we have decided to continue to use the eight years of RIIO-ED1 as the period for the regression. This is because DPCR5 workloads for tree cutting have been back-loaded to later years of the price control, contrary to how work has been forecast for RIIO-ED1. We also believe that the relative efficiencies displayed by DNOs in the RIIO-ED1 period are in line with our analysis of historical efficiencies.

9.43. We have decided not to consider growth rates in our assessment of efficient unit costs for ENATs 43-8 activity. We do not believe that growth rates alone sufficiently reflect the range of regional and topographical factors that can influence the costs of tree cutting in different DNO regions and across different spans. Other DNOs have not been able to review the data provided in support of making this change, and no other DNOs proposed to include adjustments for regional differences in our assessment.

9.44. As our results are in line with historical efficiencies and responses received on draft determinations were generally supportive of our assessment, we have decided not to change our approach to assessing ETR 132 activity for final determinations. We have removed the ratchet for the reasons described in Chapter 3.

Non-regressed areas of NOCs

9.45. Assessment of the following areas was not based on a regression analysis: severe weather - atypical; inspections and maintenance; NOCs other; tree cutting (ETR 132 activity only).

9.46. Our estimate of efficient costs and workloads was carried out in a number of ways depending on the activity area being assessed.

Severe Weather 1 in 20 events

Decision and results

9.47. We have decided to change our assessment approach for severe weather 1 in 20 (SW 1-20) events from draft determinations.

9.48. We have estimated an industry wide view of required expenditure. This is based on 50% of the DPCR5 UQ per annum cost of SW 1-20 events multiplied by the probability of a SW 1-20 event occurring, plus 50% of the DNOs' forecast expenditure. We have allocated this expenditure based on the overhead line (OHL) MEAV.

9.49. For SW 1-20 allowances nine of the ten slow-track DNOs forecast costs totalling £78m.[36] Our modelled view is £47m, a £31m disallowance. Our modelled view is £47m, a £31m disallowance. This is lower than at draft determinations for the reasons set out above.

Table 9.5: Severe weather 1 in 20 modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	2	2	2	4	1	55%
NPgN	20	20	20	4	-16	-79%
NPgY	18	17	18	3	-15	-81%
WMID	13	13	13	6	-6	-51%
EMID	13	13	13	6	-7	-54%
SWALES	6	6	6	5	-1	-17%
SWEST	10	10	10	8	-3	-25%
LPN						
SPN	6	6	6	3	-3	-43%
EPN	7	7	7	9	2	28%
SPD	4	4	4	4	0	9%
SPMW	4	4	4	4	0	9%
SSEH	8	8	8	7	-1	-15%
SSES	8	8	8	8	0	-3%
Total	119	118	119	72	-48	-40.1%
Total excl WPD	**78**	**76**	**78**	**47**	**-31**	**-39.8%**

[36] LPN do not incur costs as SW1 in 20 allowances are based on overhead lines and LPN do not have these.

Draft determinations approach

9.50. For SW 1-20 events, we used a unit-cost based assessment only. We took the minimum of the unit costs from the RIIO-ED1 forecast and the unit costs of the DPCR5 period rolled forward.

Responses

9.51. A number of DNOs felt that our draft determinations methodology gave inconsistent results. A common issue raised was that DNOs who had not suffered a SW1-20 had been awarded their full submitted costs.

9.52. One stated that for the draft determinations Ofgem had been inconsistent in its assessment of allowances for different DNOs. This respondent felt that as some DNOs had proposed significant and unprecedented levels of severe weather 1-20 forecast costs, yet still broadly had their full forecast allowed, Ofgem needed to revisit its analysis.

9.53. One DNO suggested we should set allowances based on the average costs proposed by DNOs for the RIIO-ED1 period; this would be more consistent with its approach in other areas of the cost assessment.

Reasons for our decision

9.54. We reviewed our assessment of SW 1-20 events in light of the responses received from DNOs and following a further assessment of DNOs' actual DPCR5 expenditure on SW 1-20 events. We decided that it was appropriate to change the calculation of our modelled view of SW 1-20 expenditure. For final determinations we have used actual expenditure from DPCR5, the probability of an event occurring during RIIO-ED1, and the DNOs' forecast expenditure to create an industry wide estimate of expenditure.

9.55. We have allocate this industry wide estimate across the DNOs based on each DNO's share of the industry's OHL MEAV. We use OHL MEAV as this is the element of a DNO's network most susceptible to a severe weather event.

Inspections and Maintenance

Decision and results

9.56. For inspections and maintenance we maintain the approach used at draft determinations. Our volumes assessment is based on MEAV (with a different MEAV used for LPN to reflect its lack of overhead lines). Our unit cost assessment is calculated using the industry median as a benchmark.

9.57. For inspections and maintenance, the ten slow-track DNOs have collectively forecast £757m. The forecast has increased from draft determinations due to increases in inspections and maintenance associated with UKPN's link box programme. Our modelled costs are lower at £728m.

Table 9.6: Inspection and maintenance modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	65	65	65	61	-3	-5%
NPgN	47	45	47	43	-4	-9%
NPgY	66	64	66	61	-5	-7%
WMID	70	70	70	66	-4	-6%
EMID	63	75	63	71	7	12%
SWALES	36	42	36	40	4	10%
SWEST	50	60	50	57	6	12%
LPN	113	106	115	123	8	7%
SPN	70	69	72	65	-7	-9%
EPN	116	112	118	106	-12	-10%
SPD	53	59	53	55	3	5%
SPMW	67	75	67	71	4	5%
SSEH	32	40	32	40	7	23%
SSES	124	109	124	103	-20	-16%
Total	972	990	978	961	-17	-1.7%
Total excl WPD	**752**	**744**	**757**	**728**	**-30**	**-3.9%**

Draft determinations approach

9.58. At draft determinations we carried out a volumes assessment based on MEAV. We used a different MEAV for LPN to reflect the lack of overhead lines on its network.

9.59. For our unit cost assessment we calculated the efficient costs for DNOs using the industry median as a benchmark.

Responses

9.60. Only two DNOs commented on our assessment of inspections and maintenance.

9.61. One DNO agreed that it was not practical to conduct volume analysis on individual asset types due to the materiality of the volumes, differing company practices and outstanding issues with defining the boundaries between maintenance and refurbishment activities. It felt that MEAV is a reasonable overall indication of asset base size and its use is consistent with other areas of the cost assessment. This DNO felt that our unit cost assessment could accommodate definitional issues at an activity level to give an overall view of cost efficiency.

9.62. One DNO felt that the inspections and maintenance assessment should be based on work undertaken by DNOs in accordance with company policy, and allow submitted costs for DNOs to meet legal, safety and statutory obligations. This DNO felt that MEAV was an arbitrary and inappropriate driver for the volumes assessment.

Reasons for our decision

9.63. We continue to think that MEAV is an appropriate driver for our volumes assessment. We believe that MEAV gives a strong representation of DNOs' asset populations and that its use is consistent with other areas of the cost assessment. We do not believe that a qualitative assessment of individual DNOs' work plans for inspections and maintenance is appropriate.

9.64. We think our unit cost based assessment is appropriate given the relatively narrow scope of different inspection and maintenance activities between DNOs.

9.65. Given the balance of responses received on this area we think our assessment is appropriate.

NOCs Other

9.66. NOCs other includes substation electricity, dismantlement and remote location generation.

Decision and results

9.67. For our assessment of NOCs other we keep the approach used for draft determinations.

9.68. For NOCs other, the ten slow-track DNOs have collectively forecast £220m. Our efficient view of costs is £26m lower, with our modelled costs at £194m. There are no changes in either submitted or modelled costs from draft determinations.

Table 9.7: NOCs other modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	15	15	15	15	0	0%
NPgN	7	8	7	8	0	4%
NPgY	14	14	14	14	0	2%
WMID	20	19	20	19	-1	-4%
EMID	24	22	24	22	-2	-7%
SWALES	9	8	9	8	-1	-14%
SWEST	14	15	14	15	0	3%
LPN	23	20	23	20	-3	-12%
SPN	19	16	19	16	-4	-19%
EPN	36	35	36	35	-1	-3%
SPD	17	16	17	16	-1	-7%
SPMW	19	10	19	10	-8	-44%
SSEH	61	52	61	52	-9	-15%
SSES	8	8	8	8	0	0%
Total	287	256	287	258	-29	-10.2%
Total excl WPD	**220**	**193**	**220**	**194**	**-26**	**-11.8%**

Draft determinations approach

9.69. For substation electricity we apply an industry median unit cost using eight years of RIIO-ED1 data to each substation.

9.70. For dismantlement we apply the industry median percentage annual increase in costs between DPCR5 to RIIO-ED1 to each DNO's DPCR5 costs.

9.71. For remote location generation fuel costs and remote location generation operation and maintenance costs, our modelled costs are based on each DNO's actual annual average DPCR5 costs.

Responses

9.72. Two DNOs suggested alternative methodologies for assessing substation electricity. One proposed to exclude higher voltage substations from the benchmarking. The other proposed assessing supply contracts.

Reasons for our decision

9.73. For dismantlement and remote location generation we did not receive any comments and decided to keep our approach. For substation electricity we reviewed the proposed options but remain confident of the quality of the data, and have decided to use the same methodology as at draft determinations.

Ex ante call out smart meter costs

9.74. There are four cost categories that comprise the DNO operational smart meter costs:

- **on-site**: subject to a smart meter volume driver. A proportion of costs are ex ante costs. The remainder is subject to an uncertainty mechanism
- **indirect IT and data services for smart meter roll out**: subject to smart meter volume driver. A proportion of costs are ex ante costs. The remainder is subject to an uncertainty mechanism
- **ongoing smart meter IT and data services up to 2021-22:** subject to pass through (discussed in Chapter 11)
- **ongoing smart meter IT and data services post 2021-22**: not subject to pass through (discuss in Chapter 11).

9.75. Our assessment in this section refers only to the ex ante element of the first two items above.

Decision and results

9.76. Our assessment is unchanged from draft determinations. We continue to benchmark the DNOs' submitted unit costs against the industry lower quartile and on volumes we provide an ex ante allowance based on a 2% call out rate. We continue to include a qualitative adjustment for LPN.

9.77. Table 9.8 details the results of the assessment of smart meter roll out costs.

9.78. The ten slow-track DNOs submitted £127m in smart meter costs and our modelling allows £131m, £4m (2.9%) above the submitted costs.

9.79. Both the submitted and modelled costs for final determinations are the same as draft determinations.

Table 9.8: Smart meter call out modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	12	13	12	13	1	9%
NPgN	12	10	12	10	-2	-17%
NPgY	17	14	17	14	-3	-17%
WMID	10	15	10	15	5	56%
EMID	10	16	10	16	6	56%
SWALES	5	7	5	7	2	49%
SWEST	6	10	6	10	3	52%
LPN	20	12	20	12	-8	-39%
SPN	14	14	14	14	0	1%
EPN	23	22	23	22	-1	-3%
SPD	8	14	8	14	6	67%
SPMW	6	9	6	9	4	59%
SSEH	3	5	3	5	1	36%
SSES	13	18	13	18	6	43%
Total	158	178	158	179	21	13.0%
Total excl WPD	**127**	**131**	**127**	**131**	**4**	**2.9%**

Draft determinations approach

9.80. Our volume assessment provided an ex ante allowance based on a 2% call out rate. For the unit cost analysis, we benchmarked DNOs' submitted unit costs against the industry lower quartile. We included a qualitative adjustment for LPN to take into account extra costs related to the higher number of multi-storey properties in London compared to the rest of GB.

Responses

9.81. Most DNOs supported our approach. One DNO challenged the unit cost methodology. It noted that there are additional costs for asbestos meter boards, and the cost disallowance would be inconsistent with its duties on these. Another DNO requested additional clarification on the disallowance of costs related to streetworks and network constraints.

Reasons for our decision

9.82. We think there is uncertainty over the costs of the smart meter roll out programme until it commences. For this reason we benchmark using the lower quartile (LQ). We also note that costs will be incurred for the removal or protection of asbestos meter boards but the LQ benchmarking allows for these costs in our benchmarking. We consulted the HSE regarding asbestos .HSE suggests that, following a risk assessment, the least cost encapsulation method is acceptable for meter boards.

9.83. For LPN we provided a 29.9% qualitative adjustment on its unit costs. Based on the information provided we consider that this is justified due to the significantly higher number of multi-storey dwellings in the London area. Other extra costs (eg civils or streetworks) can occur throughout the UK, and should be covered by the industry lower quartile unit cost.

Summary of NOCs results

9.84. **In total, the ten slow-track DNOs estimated that they will spend £3,807m on NOCs activities in RIIO-ED1. Our assessments of the individual activities suggest this should be £3,789m. Our modelled costs are £18m (0.5%) lower than DNO forecast costs.**

Table 9.9: NOCs modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	320	326	320	332	11	4%
NPgN	303	273	303	261	-41	-14%
NPgY	455	430	455	419	-36	-8%
WMID	379	366	380	356	-24	-6%
EMID	397	363	397	364	-32	-8%
SWALES	210	211	210	212	3	1%
SWEST	335	343	335	347	12	4%
LPN	335	307	337	340	2	1%
SPN	364	347	365	345	-20	-5%
EPN	602	603	604	608	4	1%
SPD	320	326	320	339	18	6%
SPMW	340	350	340	355	15	4%
SSEH	266	264	266	281	15	6%
SSES	496	490	496	510	14	3%
Total	5,123	5,000	5,129	5,069	-60	-1.2%
Total excl WPD	**3,177**	**3,716**	**3,807**	**3,789**	**-18**	**-0.5%**

10. Closely Associated Indirects, Business Support and Non-op Capex

Chapter summary

Our assessment of indirect costs - closely associated indirects costs, business support costs and non-operational capex costs.

Indirect costs overview

10.1. The direct costs of carrying out work on a DNO's network are captured in network investment costs and network operating costs (NOCs). DNOs also incur indirect costs. These include costs that support the direct activity, known as closely associated indirect (CAI) costs, costs that support the running of a DNO's business known as business support costs (BSCs) and non-operational capital expenditure (capex) such as office buildings and certain IT systems.

10.2. Some activities within CAI costs and BSCs are carried out at a group level rather than by individual DNOs. Each company has its own methodology for allocating such costs between its DNOs and other companies within the same group.

CAI costs

10.3. CAI costs comprise the following ten activities:

- network design and engineering
- project management
- system mapping – cartographical
- engineering management and clerical support (EMCS), including wayleaves
- stores
- network policy
- control centre
- call centre
- vehicles and transport
- operational training including workforce renewal.

10.4. We also report streetworks costs in this section.

10.5. We group the CAI activities into five categories for the purposes of our assessment and for reporting in this section as follows:

- regressed areas: network design and engineering, project management, system mapping, EMCS (excluding wayleaves), stores, network policy, control centre and call centre
- wayleaves
- vehicles and transport
- operational training including workforce renewal
- streetworks.

Decision and results

10.6. For the regressed areas, we are not making changes to our draft determinations approach. We aggregate the eight categories and run regression analysis using eight years of RIIO-ED1 forecast data, and MEAV and asset additions as the explanatory variables. We still make a qualitative adjustment for the three UKPN DNOs but do not normalise its LV control costs by removing from control centre costs prior to benchmarking.

10.7. For wayleaves, we continue to adopt ratio analysis to calculate unit costs. We still use 13 years of data but now use the number of supports (towers and poles) as the cost driver, rather than total network length used at draft determinations.

10.8. For vehicles and transport, we are making no changes to our approach at draft determinations and use ratio analysis using 13 years of data and MEAV as the cost driver. We continue to analyse CAI vehicles together with non-operational capex vehicles.

10.9. For operational training, our assessment is unchanged from draft determinations, with the exception of a minor change to normalise for differences in retirement age. We separately assess workforce renewal and non-workforce renewal costs using ratio benchmarking at a DNO group level over the eight years of RIIO-ED1.

10.10. For streetworks, the only change we make from draft determinations is to allow an efficient level of permit conditions costs. This follows a qualitative assessment of these costs. At draft determinations we disallowed all such costs due to insufficient evidence. Our approach to assessing permit and lane rental costs remains unchanged. For permits, volumes and unit costs are taken as the lower of actual annual average costs of each DNO actuals and its RIIO-ED1 forecasts. For lane rentals, volumes and unit costs are taken as the lower of actual annual average costs of each DNO and its RIIO-ED1 forecasts.

10.11. Table 10.1 details the results of the assessment of all CAI costs (ie the combined results of the five separate assessments set out above).

10.12. The ten slow-track DNOs submitted £3,349m in CAI costs and our modelling allows £3,413m, an increase of £63m (1.9%) above their forecasts. These results are in line with the fact that DNO forecasts for the RIIO-ED1 years included considerable efficiencies compared to their historical CAI costs.

10.13. The submitted costs for final determinations are the same as they were at draft determinations but the modelled costs are £13m higher. A combination of the above changes and our amendment to MEAV (see Chapter 3) explains the changes, which affect the DNOs.

Table 10.1: CAI modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	325	380	325	374	49	15%
NPgN	231	234	231	237	6	3%
NPgY	270	300	270	299	29	11%
WMID	401	393	401	399	-2	-1%
EMID	399	420	399	417	18	5%
SWALES	225	227	225	239	14	6%
SWEST	329	305	329	320	-9	-3%
LPN	334	325	334	317	-16	-5%
SPN	378	337	378	331	-47	-13%
EPN	510	508	510	510	-1	0%
SPD	273	296	273	304	31	11%
SPMW	297	297	297	305	7	2%
SSEH	251	231	251	249	-2	-1%
SSES	480	490	480	487	7	2%
Total	4,702	4,746	4,703	4,787	85	1.8%
Total excl WPD	**3,349**	**3,400**	**3,349**	**3,413**	**63**	**1.9%**

Regressed areas

Draft determinations approach

10.14. For draft determinations we grouped eight of the CAI activities. This addressed the boundary issues in the reporting of CAI costs and the movement of cost being reported across these categories in different business plan submissions. It provided statistically robust results.

10.15. In setting our approach to regressions, we set a three-pronged test as follows: a) the cost drivers must make economic and/or engineering sense; b) the results must pass key statistical tests; and c) the results must pass a sense check. We tested a large range of regressions using different cost drivers and different time periods. We narrowed this down based on meeting these criteria.

10.16. The regression used eight years of RIIO-ED1 forecast data. The significant industry wide reduction in annual costs from DPCR5 to RIIO-ED1 raised the question of whether we should use only historical data (2010-11 to 2013-14) to estimate the parameters in the model, focus only on forecast data (RIIO-ED1), or a combination of both. A model based on DPCR5 data only, would have provided DNOs with modelled costs significantly greater than their submitted costs. Models that combined the two periods did not pass our statistical tests due to the structural break in the data. Therefore, we used eight years of forecast data in the regression. The use of eight years of data also avoided the need to scale the output from the regressions, which was criticised in our fast-track assessment.

10.17. MEAV and the efficient value of asset additions were the explanatory variables in the regression.[37] The identification of appropriate cost drivers was the key first step in the modelling process. We built upon work with our engineering consultations as well as discussions with the DNOs to determine appropriate explanatory cost drivers. Both the scale of a network and the workload on that network are widely accepted to drive CAI costs. All other things being equal, the larger the network, the more work that would be required to maintain that network, and the more direct work done on a network, the more indirect costs will be incurred (for example, design costs and project management costs). MEAV and asset additions are proxies for scale and workload, respectively. MEAV was widely supported as a driver. Asset additions, while it does not reflect all direct activity, it does cover both load and non-load-related activity. As such, it does not favour replacement over reinforcement or vice versa. As we decided to benchmark based on forecast data, it was important that we chose cost drivers that reflect the relative future workloads of the DNOs.

10.18. We ran the regression at DNO rather than group level. There was insufficient evidence of shared costs for these CAI categories to justify a group level analysis. We sought data from the DNOs to allow us to make a more informed judgement on the level of shared costs, but the interpretation of this from the DNOs varied and was not robust enough to use. We also found that the group level regressions did not give plausible results.

10.19. There is no single metric or method to assess the statistical performance of models mechanistically, but we were satisfied with the regression using the above explanatory variables and eight years of forecast data. Following a sense check of the results we considered our model provided too harsh a reduction to the forecast costs of three UKPN licensees. The UKPN and WPD groups are relatively similar in terms of scale and we therefore expected our model to produce similar results in CAI costs, which are largely driven by scale. We made an adjustment to the UKPN group costs to reflect this and this was reapportioned to the UKPN DNOs (LPN, EPN and SPN) based on the proportion of their submitted forecasts. This positive adjustment did not change the overall ranking on CAI costs.

Responses

10.20. DNOs broadly supported our approach at draft determinations, recognising the need to meet all three tests set out. For example, one DNO noted that while further disaggregation may present a more intuitive fit with cost drivers this may not provide a more robust statistical model.

[37] The efficient value of asset additions accepted a DNO's submitted asset additions volumes but used our view of efficient unit cost.

10.21. Most DNOs welcomed the inclusion of asset additions as a cost driver. One DNO questioned the use of this for categories such as call centres and stores. Another noted that asset additions do not fully reflect the activities that drive these categories of CAI costs and suggested using submitted direct costs as a driver. The same DNO also questioned the use of eight years of data in the CAI regressions, noting that this is inconsistent with the totex regression which used 13 years of data.

10.22. One DNO suggested that we should normalise out its LV control costs from control centre costs as it is the only DNO group to operate LV control and that is 24/7 operational. This was not raised prior to the publication of draft determinations.

Reasons for our decision

10.23. For the regressed categories, we make no changes to our draft determinations approach. We consider that MEAV is a good driver for the overall activities that a DNO undertakes, which is why we have also used it as a driver for totex. The asset additions reflect the gross work on assets that the DNO undertakes. We do not think it is appropriate to use the DNOs' submitted costs as a driver as this would reward inefficient companies. While the asset additions are not adjusted for our view of efficient volumes, it is adjusted for our view of efficient unit costs.

10.24. We reviewed the case for normalising UKPN's LV operational control costs with our engineers. We do not consider that it is necessary to make an additional qualitative adjustment for this as these costs are adequately covered by our existing qualitative adjustments.

Wayleaves

Draft determinations approach

10.25. We used ratio analysis for our assessment at draft determinations. This calculated unit costs using total network length (overhead and underground) as the cost driver and 13 years of data. We believed using 13 years of data accounted for the forecast increases in wayleave costs during RIIO-ED1 due to proactive land agents seeking payments.

Responses

10.26. At one of the bilateral meetings, one DNO raised concerns with the use of network length as a cost driver. It suggested that using only overhead lines (ie removing underground cables) was a more appropriate cost driver. This was because wayleave costs per km are influenced significantly by the percentage of overhead line.

Reasons for our decision

10.27. For final determinations we now use the number of supports (towers and poles) as the cost driver, rather than network length. All other elements of the assessment remains the same as at draft determinations. Due to the adoption of this cost driver, all of LPN's costs are disallowed as it does not have towers and poles. LPN still incurs wayleave costs for rental of substation and other rentals, and therefore we make a qualitative adjustment to allow its submitted costs.

10.28. When reviewing the use of total network length as a cost driver with our engineering consultants, we came to two main conclusions.

10.29. We identified that the inclusion of underground cables was not appropriate. Most of the assets installed on privately owned land and subject to wayleave payments, will be overhead lines. It is quite rare for underground cables of any significant length to be installed on anything other than public land. Where underground cables are installed, compensation will usually not be relevant, as the route will not sterilise the use of the ground above. By including underground cables in the network length, there is the risk of disadvantaging those DNOs with a higher than average ratio of overhead line to underground cable.

10.30. We identified the number of supports as a more appropriate cost driver than the length of overhead lines. It is these supports that more directly influence compensation payments as it is the supports that sterilises the land owners' use of the ground. In addition, the vast majority of low voltage overhead lines will be along public highways and will not attract wayleave costs.

Vehicles and Transport

Draft determinations approach

10.31. We analysed CAI vehicle and transport costs with non-operational capex vehicle and transport costs to avoid any bias in our modelling between those DNOs that lease and those DNOs that buy vehicles. We used ratio analysis taking the industry median costs based on 13 years of data, adopting MEAV as the cost driver. Using 13 years of data smoothed the lumpy nature of vehicles costs. The modelled costs were then reallocated to CAI and non-op capex based on the ratio of submitted expenditure in these two areas.

Responses

10.32. The majority of DNOs agreed with our approach. However, at a bilateral meeting one DNO disagreed with using MEAV as a cost driver. It noted that vehicles and transport activities have a very close relationship with direct activities and are best assessed by reallocating vehicles and transport costs across direct costs using direct labour as basis of allocation. It suggested that if vehicle and transport activity must be assessed separately, then a more appropriate driver is the number of direct employees associated with direct activities.

Reasons for our decision

10.33. We make no changes to our approach used for draft determinations and continue to use ratio analysis using 13 years of data and MEAV as a cost driver.

10.34. The scale of the network will determine the number of vehicles required to maintain that network.

10.35. Both suggestions above rely on direct labour (FTE) data – the first to apportion costs and the second as a cost driver. We reject the use of FTE data on the basis that it is not consistently reported by all DNOs. In addition, one of the principles we adhere to where possible is not use endogenous cost drivers. This was agreed with the DNOs early in the cost assessment development work.

Operational Training and Workforce Renewal

Draft determinations approach

10.36. Operational training costs were separated into two categories - workforce renewal costs and non-workforce renewal costs. These were assessed separately using ratio benchmarking at group level over the eight years of RIIO-ED1. Workforce renewal costs were benchmarked against the total number of leavers, while non-workforce renewal costs were benchmarked against the total current workforce. In calculating the number of leavers we normalised for differences in DNOs' assumed rate of non-retirement leavers. An additional normalisation was applied in calculating number of leavers to take account of differences in assumed retirement age.

Responses

10.37. One DNO was of the view that the use of median attrition rate fails to reflect the differences in staff turnover rates across different geographical areas. It suggested that it would be more appropriate to use DNO's own forecast attrition rates.

10.38. A non-DNO expressed concerns that training investment through a specific allowance for workforce renewal has been withdrawn and finance for the sector as a whole reduce, yet service levels are expected to improve.

Reasons for our decision

10.39. Our operational training assessment is unchanged from draft determinations. While we accept that some DNOs have had historically higher than average attrition rates, we do not accept this as an argument for using company specified attrition rates rather than the median value in our assessment. Those DNOs with higher attrition also have higher average salaries per FTE (excluding non-price control activities). It is our view that these higher salaries should be sufficient to mitigate any disadvantages related to staff retention.

10.40. The workforce renewal costs are no longer a specific allowance but they are still part of the ex ante allowances. They have not been removed.

Streetworks

10.41. Streetwork costs are embedded in the relevant cost activity tables and fall into two groups: existing streetwork costs and new streetwork costs. Existing streetwork costs comprise those costs associated with notification penalties, inspections, inspection penalties, congestion charges and set up costs. New streetwork costs comprise permits, permit penalties, condition costs, and lane rentals. Streetwork administration costs are assessed as part of EMCS costs.

Draft determinations approach

10.42. For draft determinations, the existing streetwork costs remained embedded in the relevant activity and were therefore subject to the overall assessment of that activity. New streetwork costs were stripped out of the relevant activity and subjected to the assessment detailed in Table 10.2.

Table 10.2: New streetwork costs draft determinations approach

Category	**Approach**
Permit and permit penalties	Eight of the 14 DNOs submitted permit costs. As permit volumes and costs are specific to particular local authorities and highway authorities, industry benchmarking was not appropriate. Volumes were taken as the lower of the DNO average annual actuals or the DNO RIIO-ED1 forecast. Unit costs were taken as the lower of DNO average annual actuals or RIIO-ED1 forecast. Our view took into account that in very limited cases incurring a permit penalty may be the most cost effective solution.
Permit condition costs	These are costs of conditions placed on permits such as night-time working. Only SSES and LPN provided forecast costs. We did not believe these were sufficiently justified and they were disallowed.
Lane rentals	There is only one lane rental scheme, the TfL scheme that has been in operation for over 12 months to July 2013 and therefore only this scheme satisfied our criteria for setting ex ante allowances (TfL implemented its scheme on 11th June 2012). Only two DNOs have costs under this scheme – LPN and SSES. Volumes were taken as the lower of actual annual average volumes (2011-11 to 2013-14) and RIIO-ED1 volumes. For unit costs, SSES' unit costs were significantly higher than LPN's with no clear justification. The LPN unit cost was applied to both DNOs. The LPN unit cost was based on the lower of actual annual average unit costs (2010-11 to 2013-14) and RIIO-ED1 unit costs.

Responses

10.43. Most DNOs supported the approach to the streetworks assessment, but one challenged the disallowance of permit condition costs. It noted that there are additional costs associated with ensuring compliance with the specific requirements of different permit schemes. Complying with the requirements imposes additional planning and preparation work on the DNO. These requirements are outside the control of the DNOs and are bespoke to each authority implementing the permit schemes.

Reasons for our decision

10.44. Our approaches to assessing all elements of streetwork costs remain unchanged. However, we now accept the majority of forecast permit condition costs following the submission of further evidence.

10.45. We accept that permit condition costs are bespoke to each local authority or highway authority and therefore need to be justified on a case-by-case basis. In reviewing further evidence, we are satisfied that the majority of permit condition costs are justified. However, we note the volatility of these costs and we feel it is sensible to allow the lower of the DNO's DPCR5 or RIIO-ED1 (where unit cost is the condition cost per permit). This approach accepts that each DNO may incur different costs due to different conditions imposed on them but also recognises that its area that is difficult to benchmark and data is volatile.

BSCs

10.46. BSCs comprise the following five categories:

- finance and regulation
- HR and non-operational training
- property management
- CEO and group management
- IT & telecoms.

Decision and results

10.47. We have not made any changes to our draft determinations approach to assessing BSCs and there are no changes to the results.

10.48. We aggregate four of the BSC categories (finance and regulation including insurance, HR and non-operational training, property management, and CEO and group management), and subject them to ratio benchmarking using 13 years of data and MEAV as a cost driver. We conduct the analysis at an ownership group level.

10.49. Business support IT&T costs are subject to a separate assessment. This assessment is a combination of ratio analysis and expert review. The ratio analysis also uses 13 years of data and MEAV as a cost driver and is conducted at an ownership group level. The qualitative assessment carried out by our consultants is the same as that for Operational IT&T as described in Chapter 8.

10.50. The ten slow-track DNOs collectively forecast £1,727m in BSCs and our modelling allows £1,905m, an increase of £178m (10.3%). As for CAI costs, the overall assessment results are in line with the fact that DNO forecasts for the RIIO-ED1 years included considerable efficiencies compared to their historical BSCs.

10.51. ENWL incur a minor reduction to costs in our modelling (less than 2% of forecast costs) and the other DNOs in NPg, UKPN, SPEN and SSEPD ownership groups have modelled costs 8% to 18% above their RIIO-ED1 forecast costs.

Table 10.3: Business support modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	237	235	237	235	-2	-1%
NPgN	133	157	133	157	23	18%
NPgY	153	180	153	179	27	17%
WMID	207	204	207	204	-3	-1%
EMID	214	211	214	212	-3	-1%
SWALES	112	110	112	110	-1	-1%
SWEST	178	176	178	176	-2	-1%
LPN	168	181	168	181	13	8%
SPN	172	185	172	185	14	8%
EPN	221	238	221	239	18	8%
SPD	153	169	152	168	16	10%
SPMW	127	141	127	140	13	10%
SSEH	144	165	144	166	22	15%
SSES	220	254	220	255	34	16%
Total	2,439	2,604	2,438	2,607	169	6.9%
Total excl WPD	**1,728**	**1,904**	**1,727**	**1,905**	**178**	**10.3%**

Draft determinations approach

10.52. For draft determinations we comprehensively reviewed many possible alternatives for assessing BSCs. Based on the economic literature, supporting materials and previous Ofgem practices we considered and tested the following alternatives:

- aggregated and disaggregated assessment
- DNO and group level assessment
- ratio benchmarking, regression analysis, Monte Carlo simulation and combination of these
- assessment with and without fixed cost normalisation (with improved fixed cost estimation that takes account of economies of scale)
- a range of possible drivers and documented cost driver selection process
- inclusion or exclusion of insurance costs in the assessment
- different time frames: actuals (2010-11 to 2013-14), DPCR5 (2010-11 to 2014-15), RIIO-ED1 forecasts (2015-16 to 2022-23) and all 13 years (2010-11 to 2022-23).

10.53. In deciding on the criteria for the final assessment approach we considered a number of factors including the appropriateness of the assumptions, the economic rationale, performance against the statistical tests, sensitivities, the level of complexity, expert views and a final sense check of results.

10.54. The approach adopted was ratio benchmarking at an ownership group level for four aggregated BSC categories (finance and regulation including insurance, HR and non-operational training, property management, and CEO and group management). Business support IT&T costs were subject to a separate assessment. This was assessed through a combination of ratio analysis at ownership group level and expert review. It was the same expert review for operational IT&T and non-operational capex IT&T.

10.55. The cost driver was MEAV. Based on methodological selection process and our tests, MEAV was considered the most appropriate driver to describe the aggregated BSCs and the business support IT&T costs. Other drivers such as direct employees and revenue, were rejected for three key reasons: the lack of economic rationale; their endogenous nature; and significant changes were made to them by DNOs between the fast-track and the slow-track submissions, reducing our confidence in them.

10.56. The assessment did not include fixed cost normalisation. A group level assessment is undertaken which accounted to some degree for the sharing of costs across DNOs within a group. It also addressed the problem of significant differences in allocation methodologies across ownership groups, which made the DNO level data less comparable. The measure used as a comparator in the ratio benchmarking is the industry median ratio for 2010-11 to 2022-2023.

Responses

10.57. Generally there was strong support for our approach to assessing BSCs at draft determinations. However, one DNO was disappointed that we did not accept an adjustment should be made for its fixed costs as a single licensee.

10.58. Another DNO accepted our assessment of the four aggregated areas of BSCs, but raised issues with our assessment of IT&T costs. It suggested that the quantitative and qualitative approaches were not aligned as the qualitative analysis was done on a DNO specific basis, while the quantitative assessment was done at a group level. It suggested it would be more appropriate to apply full weight to the quantitative assessment.

Reasons for our decision

10.59. We have not made any changes to our draft determinations approach to assessing BSCs.

10.60. We maintain the position not to make a fixed cost adjustment for the single licensee DNO (ENWL). This is an issue of scale that applies to all DNOs to varying degrees. If we applied a fixed cost adjustment to each of the DNO allowances, we would need to change it if a DNO was subsequently purchased by, or divested from, a DNO group. We do not think that this is appropriate, and so have not included a fixed cost adjustment in our final determinations.

10.61. We believe the quantitative and qualitative assessments of business support IT&T are aligned. It is true that the qualitative assessment was initially conducted at the individual DNO level. But the quantitative assessment of BSCs, conducted at a group level, was fully considered in the consultant's approach to reviewing business support IT&T costs. The consultants ensured that the qualitative adjustments at an individual DNO level made sense at a group level.

10.62. We maintain that a weighting of 50% to the quantitative assessment and 50% to the qualitative assessment remains appropriate. As noted in Chapter 8, the quantitative assessments of operational IT&T and non-operational capex IT&T were given less weighting (25%) than that for business support. It was agreed with DNOs prior to draft determinations that the quantitative benchmarking for business support costs is more appropriate given the comparability and consistency of these DNOs costs (no trade-off issues).

Non-operational capex

10.63. Non-operational capex costs comprise the following four activities:

- property
- small tools, equipment, plant and machinery (STEPM)
- IT&T
- vehicles and transport.

10.64. The assessment of non-operational capex IT&T was combined with the assessment of operational IT&T. This is described in the operational IT&T section in Chapter 8. The assessment of non-op capex vehicles was combined with the assessment of CAI vehicles and transport, described above. This section therefore discusses only property and STEPM costs, although the results are for all four areas.

Decision and results

10.65. For non-operational property costs, we removed a ratchet, which gave DNOs the lower of our modelled view and its own forecast. We now conduct ratio analysis and apply industry median unit costs based on 13 years of data and using MEAV as a cost driver.

10.66. For STEPM, we conduct a qualitative review of each DNOs costs. We do not believe the cost data is reported consistently and therefore do not benchmark these costs.

10.67. Table 10.3 details the results of our assessment of non-operational capex costs. The ten slow-track DNOs have forecast that they will spend £629m on non-operational capex in RIIO-ED1. On average we consider that costs can be reduced by 4.1% to £604m.

10.68. Our modelled costs are £10m lower than at draft determinations for the slow-track companies, with the negative change greatest for SSEH. This is due to the change in our property assessment.

Table 10.4: Non-operational capex modelled costs (2012-13 prices)

DNO	RIIO-ED1 slow-track March submitted totex	RIIO-ED1 Draft determinations modelled costs	RIIO-ED1 slow-track final submitted totex	RIIO-ED1 Final determinations modelled costs	Difference (fd modelled minus submitted)	
	£m	£m	£m	£m	£m	%
ENWL	39	47	39	56	17	45%
NPgN	57	54	57	61	3	6%
NPgY	68	74	68	74	7	10%
WMID	91	83	91	95	4	5%
EMID	84	90	84	106	23	27%
SWALES	47	38	47	46	-1	-2%
SWEST	79	57	79	69	-10	-12%
LPN	60	54	60	49	-11	-18%
SPN	70	62	70	59	-11	-15%
EPN	96	94	96	96	-1	-1%
SPD	53	53	53	51	-3	-5%
SPMW	51	47	51	44	-7	-14%
SSEH	47	47	47	36	-11	-24%
SSES	88	81	88	79	-9	-11%
Total	930	882	930	920	-10	-1.1%
Total excl WPD	**629**	**614**	**629**	**604**	**-26**	**-4.1%**

Property

Draft determinations approach

10.69. For non-operational property costs we applied the lower of the DNO's own RIIO-ED1 forecast or the industry average over RIIO-ED1 to the eight years of RIIO-ED1.[38]

Responses

10.70. Two DNOs strongly objected to our use of a ratchet in setting non-operational capex property costs. They argued that this distorts the relative efficiency of DNOs.

Reasons for our decision

10.71. For non-operational property costs, we remove the ratchet. We now conduct ratio analysis and apply industry median unit costs based on 13 years of data and using MEAV

[38] In the draft determinations document *RIIO-ED1 business plan expenditure assessment* we stated that we applied the lower of DNO submitted and industry median unit costs (calculated using MEAV as a cost driver and 13 years of data). This is not what the model did. What was modelled is as described in paragraph 10.69.

as a cost driver. We believe median unit costs rather than lower quartile unit costs are appropriate given that we have removed the ratchet.

Small tools equipment, plant and machinery (STEPM)

Draft determinations approach

10.72. For STEPM, we used ratio analysis using MEAV as a cost driver and 13 years of data to set our modelled unit costs. We applied the minimum of our modelled and DNO forecast costs.

Responses

10.73. Similar to non-operational property costs, two DNOs strongly objected to our use of a ratchet in setting STEPM costs. One of these DNOs also noted that we must take account of the fact that DNOs have not reported costs for STEPM on a consistent basis.

Reasons for our decision

10.74. For STEPM we no longer use the quantitative benchmarking approach at draft determinations which incorporated a ratchet. Following further review, it was clear that the STEPM cost data were inconsistently reported. As such we do not believe it is appropriate to benchmark these costs. Instead we subject these costs to a DNO-by-DNO qualitative review.

10.75. In conjunction with our engineering consultants, we compared average annual expenditure in DPCR5 to RIIO-ED1 and sought justification in the narrative where this was different, and in particular where RIIO-ED1 expenditure was higher than at DPCR5. Following this review, we allow each DNO’s submitted costs.

10.76. We acknowledge that this approach does not reward DNOs for efficiency but it is only appropriate to award relative efficiency where the costs can be benchmarked. We believe that this approach ensures that where a DNO has provided a complete and detailed justification to Ofgem of its costs in this area these costs is allowed.

11. Smart grids and other innovation benefits

Chapter summary

Our approach to assessing the benefits to DNOs of using smart grids and other innovation, including changes from draft determinations.

Overview

11.1. Consumers have made significant investments in innovative projects which should allow DNOs to more efficiently invest in and operate the networks during RIIO-ED1. Our assessment of DNOs' efficient allowances includes an element to ensure benefits from these innovation investments are returned to consumers and that DNOs seriously consider how to deliver efficient and high quality network services. We expect DNOs to deliver these benefits and will monitor their performance during RIIO-ED1.

Decision and results

11.2. We have retained the approach of applying an adjustment to embed smart grids and other innovation savings in DNOs' allowances. We have reviewed the responses and have made a number of changes to our methodology for final determinations. The final determinations adjustment for smart grids and other innovation for each DNO is in Table 11.1.

Table 11.1: Value of smart grids and other innovation adjustment over RIIO-ED1

DNO	Embedded benefit (£m)[39]	Adjustment (£m)	Total smart saving (£m)
ENWL	-66	-8	-73
NPgN	-39	-21	-60
NPgY	-52	-21	-74
WMID	-43		-43
EMID	-69		-69
SWALES	-20		-20
SWEST	-33		-33
LPN	-51	-29	-80
SPN	-54	-22	-76
EPN	-73	-53	-126
SPD	-25	-55	-80
SPMW	-20	-60	-80
SSEH	-28	-14	-41
SSES	-69	-39	-109
Total	**-641**	**-322**	**-963**

Figures are rounded.

11.3. We reviewed further evidence from the DNOs to determine the level of savings in the DNOs' plans that can be attributed to smart grids and other innovative solutions. We benchmark the DNOs on the basis of these savings. We have considered two areas of savings, each discussed below.

Reinforcement

11.4. Our modelling of smart grid savings in reinforcement is disaggregated into the following areas, each with its own assessment:

- LV-EHV general reinforcement: we use UQ benchmarking of forecast savings as a proportion of submitted net expenditure in this area. We exclude expenditure on unbundling of shared services driven by thermal constraints on the service cables.
- 132kV general reinforcement: we use UQ benchmarking of forecast savings as a proportion of submitted net expenditure for all years in this area. The benchmark percentage is applied to expenditure in years 2017-18 to 2022-23.
- Fault level reinforcement: we use 75% of the best performing DNO's proportion of submitted net expenditure in this area. An UQ is not appropriate due to the small number of data points.

[39] The savings we consider to be embedded in DNOs' efficient allowances after the cost assessment. We assume that the submitted savings scale in proportion to the increase or reduction in a DNOs' allowance following the cost assessment.

11.5. The weighted average benchmark across reinforcement as a percentage of 'conventional' submitted reinforcement expenditure is under 20%.[40] This compares with a benchmark of 25% at draft determinations.

11.6. The benchmark percentages are applied to each DNO's efficient expenditure in each of the areas set out above. The level of savings DNOs are required to deliver is therefore scaled with their allowance. The scaling is according to the ratio between submitted and efficient allowances. This approach recognises that the opportunity to deliver savings is likely to be proportional to expenditure. A DNO with a higher reinforcement allowance has the opportunity to deliver a higher absolute value (but the same proportion) of savings.

11.7. The savings embedded in DNOs' business plans are also scaled in this way as we assume the same proportion of savings are embedded in the efficient allowances as in submitted forecasts. If a DNO's allowance is reduced in the cost assessment, it is appropriate to assume the absolute value of embedded benefits also reduces, but the proportion remains the same. As a result, a DNO that is better than the benchmark will be required to deliver a greater level (but same proportion) of benefits as it has a greater opportunity to do so. Conversely, a DNO that is worse than the benchmark will not be required to deliver as high a level (but same proportion) of benefits as it has less opportunity to do so because it has a smaller allowance.

Other cost areas

11.8. We use the best performing DNO across all other cost areas (where smart grid savings were identified) in aggregate as the benchmark for potential savings. The savings forecast by this DNO fall into the following cost categories:[41]

- asset replacement and refurbishment
- troublecall and ONIs
- inspection and maintenance
- operational IT and telecoms.

11.9. The benchmark is calculated as the forecast savings as a percentage of requested expenditure across these cost categories. The total potential savings are calculated by multiplying this benchmark by the total efficient expenditure in these categories.

11.10. The savings are apportioned between DNOs and cost areas on the basis of expenditure in each area. For example, if a DNO has 10% of industry expenditure across the relevant cost areas in asset replacement and refurbishment, 10% of the total savings that should be delivered will be allocated to that DNO's asset replacement and refurbishment allowance.

[40] Conventional submitted reinforcement expenditure refers to the implied expenditure DNOs would have submitted had the forecast not included smart grid savings. It is the sum of submitted expenditure and smart grid savings.
[41] A DNO also forecast savings in tree cutting.

11.11. Embedded savings in other cost areas are scaled according to the ratio between submitted and efficient allowances (as for reinforcement).

11.12. The cost categories of asset replacement and refurbishment have been combined in our assessment as costs in one category can deliver benefits in the other. The adjustment to replacement and refurbishment elements of DNOs' allowances is therefore calculated in aggregate. This is re-allocated between the two cost categories in proportion to expenditure in each.

Smart metering benefits

11.13. We include the net savings DNOs have claimed from the use of smart metering data in our benchmarking. We expect the savings identified in our benchmarking to be delivered through a combination of smart solutions including through the use of smart metering data. We have not added a further stretch related specifically to smart metering.

Draft determinations approach

11.14. Table 11.2 shows the value of the proposed adjustment at draft determinations for each DNO.

Table 11.2: Proposed value of smart grids and other innovation adjustment over RIIO-ED1 at draft determinations

DNO	Embedded benefit (£m)	Adjustment (£m)	Total smart saving (£m)
ENWL	-36	-36	-72
NPgN	-13	-37	-50
NPgY	-23	-44	-67
WMID	-28		-28
EMID	-60		-60
SWALES	-3		-3
SWEST	-19		-19
LPN	-52	-16	-68
SPN	-45	-23	-68
EPN	-52	-49	-101
SPD	-21	-42	-63
SPMW	-19	-47	-66
SSEH	-15	-29	-44
SSES	-21	-73	-94
Total	-405	-396	-801

Figures are rounded.

11.15. For draft determinations we considered evidence from a range of sources to assess the potential cost savings in reinforcement and other cost areas, including savings from the use of smart metering data. To ensure consistent treatment between

DNOs we assessed whether the claimed benefits in DNOs' business plans were from the use of smart solutions. We rejected some of the DNOs' claims where at least one other DNO was doing the same activity as 'business-as-usual'.

11.16. We used the Department of Energy and Climate Change's (DECC) January 2014 impact assessment for the smart metering programme to determine the level of benefits DNOs should be achieving from the use of the smart metering data.

11.17. We used evidence from the DNOs' business plans and their Transform models[42] to determine a forecast of the potential savings achievable in reinforcement. We set a benchmark of 25% savings compared to a baseline of 'conventional' expenditure. This was equivalent to £196m. We assumed that these savings could be delivered either through the use of smart grid solutions or smart metering data.

11.18. We only accepted embedded benefits for one DNO in cost areas outside reinforcement. We extrapolated these benefits across all slow-track DNOs to determine the smart grid savings possible in these areas. We added only some of the benefits DNOs should achieve in these cost areas through the use of smart metering data to account for potential double counting. Noting the uncertainty in the level of savings, we applied a more conservative view of potential benefits of £199m.

11.19. The savings identified were combined into a single pot and distributed across DNOs in proportion to totex. Each DNO's embedded smart grid and smart metering savings were netted off. The total reduction to slow-track DNOs' allowances was £396m.

11.20. Savings allocated to each DNO were apportioned across each cost area according to a fixed weighting.

Responses

11.21. Most DNOs disagreed that there is evidence that more savings from smart grids and smart metering can be achieved than those already in their business plans. Some DNOs accepted the principle of our adjustment and that more savings could be included in their allowances. They disagreed on the size of the adjustment. A number of DNOs thought smart grid savings should be delivered to consumers via the efficiency incentive during the period with no ex ante adjustment. One DNO proposed a mid-period review of smart grid savings to set an adjustment for the remainder of the RIIO-ED1 period.

11.22. An energy supplier supported our proposed adjustment and suggested applying a further reduction to DNOs' allowances. A consumer organisation perceived that the DNOs are reluctantly embracing the opportunities of smart grids and smart metering. It supported the proposed adjustment. A transmission network operator argued that the

[42] More information on the Transform model can be found in the publications on the SGF web page: https://www.ofgem.gov.uk/electricity/distribution-networks/forums-seminars-and-working-groups/decc-and-ofgem-smart-grid-forum

adjustment for smart grids was not sufficiently well justified. A trade union was concerned that reducing DNOs' allowances will increase the risk they bear.

11.23. The DNOs made a number of more specific comments on our methodology. These are discussed below.

Savings embedded in DNOs' business plans

11.24. The DNOs argued that we incorrectly disallowed smart grid savings claimed in their business plans. They argued that we had categorised a number of smart solutions as 'business as usual' activities. They asked us to reconsider the savings we accept as from smart solutions.

11.25. The DNOs have provided additional evidence to support their claims that the solutions they are planning to deploy are smart and more innovative than a conventional alternative. A number of DNOs have identified additional smart solutions in their plans.

Reinforcement savings

11.26. The DNOs proposed a separate assessment for areas of reinforcement not covered by the Transform model: 132kV general reinforcement, all fault level reinforcement, shared service unbundling, and reinforcement to solve harmonic issues.

11.27. They argued that an adjustment should not be made to reinforcement schemes that are already designed or in progress as it is not possible to include additional smart grid savings. A number of DNOs argued that we should review all scheme papers to determine the level of savings appropriate in each case.

Savings from smart metering

11.28. The DNOs did not support our use of the most recent impact assessment for the smart metering programme produced in January 2014 by DECC. They considered the savings in the ENA's smart metering report from 2013 to be more appropriate.

11.29. The DNOs argued that as suppliers control the roll out of smart metering we should not hold DNOs to delivering the level of benefits in the DECC impact assessment. They argued that we should consider net rather than gross smart metering benefits as they are dependent upon data and IT expenditure. While the DECC impact assessment has higher benefits than the DNOs' plans, the DNOs argued that it also expects higher levels of expenditure. The DNOs noted that we should net off the data costs after the end of the smart meter roll out. Data costs are not funded by consumers after the roll out and therefore DNOs should retain savings to cover these costs.

Savings in other cost areas

11.30. The DNOs argued that we should not use the savings forecast by one DNO in a single cost category to extrapolate potential savings for the industry.

Allocation of smart grid savings

11.31. A number of DNOs argued that the allocation of savings across DNOs should better take account of each DNO's ability to deliver those savings. They argued that totex is not a good driver for opportunity for smart grid savings. They proposed allocating on the basis of expenditure in each cost category.

Double counting

11.32. The DNOs argued that there may be double counting of savings between smart grids and smart metering. A DNO argued that we are double counting savings between this assessment and ongoing efficiency. It claimed that a proportion of its ongoing efficiency will be delivered through the use of smart grid solutions.

11.33. The DNOs argued that there may be double counting between the smart grids assessment and the general cost assessment.

Other

11.34. A DNO proposed using the level of each DNO's innovation funding to determine the level of savings each DNO should achieve.

11.35. A DNO argued that we had inconsistently recognised enabler costs. It argued that all DNOs would have expenditure on IT upgrades to roll out smart grid solutions and that we were penalising it for being transparent about these costs.

Reasons for our decision

11.36. We have seen evidence that a number of DNOs have not embedded sufficient savings from smart grids, innovation and smart metering in their business plans. We consider that it is appropriate to adjust DNOs' allowances accordingly. We expect DNOs to deliver further savings and these will be shared with consumers via the efficiency incentive.

Savings embedded in DNOs' business plans

11.37. We have reviewed the further information provided by DNOs and have accepted the majority of claimed savings as being smart or innovative. We gave DNOs many opportunities to provide evidence. For us to accept a solution as smart it had to either have been developed using innovation funding during DPCR5 or be demonstrably smarter or more innovative than what other DNOs do as business as usual. Table 11.3 lists the solutions we accepted as smart in our assessment.[43]

Table 11.3: Solutions accepted as smart or innovative

Solution	Newly accepted since draft determinations?
Hybrid generator	Yes
Smart copper theft detection	Yes
Submarine cable monitoring	Yes
Power line carrier	Yes
Chromatic analysis of insulating oil	Yes
Ecoplugs	Yes
Online transformer oil regeneration	Yes
Condition based risk management	Yes
Online tap changer acoustic monitoring	Yes
Partial discharge monitoring	Yes
Wood pole condition monitoring	Yes
Alternatives to creosote wood poles	Yes
Fault current limiter	Accepted at draft determinations
LV network automation and automatic load allocation	Accepted at draft determinations
Demand side response	Accepted at draft determinations
Automatic voltage control	Accepted at draft determinations
Enhanced meshing	Accepted at draft determinations
Dynamic transformer ratings	Accepted at draft determinations
Real time thermal ratings of overhead lines	Accepted at draft determinations
STATCOM	Accepted at draft determinations
Phase shifting transformer	Accepted at draft determinations
Energy efficiency	Accepted at draft determinations
Generator constraint management	Accepted at draft determinations
Weather impact and response modelling	Yes
Live line tree felling	Yes
Intelligent control devices for EVs	Accepted at draft determinations
Generator providing network support	Accepted at draft determinations
Other smart solutions from Transform model[44]	Accepted at draft determinations

11.38. In a number of cases where we have recognised a DNO's solution as smart or innovative we have been unable to accept the level of savings the DNO has claimed. In some cases DNOs did not calculate the savings incrementally relative to the most advanced alternative solution that could be considered business as usual and therefore were inflating the savings claimed. Table 11.4 explains our reasons for not accepting the submitted level of savings in each case.

[43] Note that these solutions may have a number of different variants. Some variants may not meet our criteria as being smart or innovative. For further information on the specific variants being implemented by DNOs, please see their business plans.
[44] Full list of the solutions in the Transform model: https://www.ofgem.gov.uk/ofgem-publications/56823/ws3-ph2-solution-annex-v1.0.pdf

Table 11.4: Smart solutions where we do not accept the quantification of savings

Solution	DNO	Reason for not accepting all savings
Condition-based risk management (CBRM)	NPg, WPD, UKPN	Savings calculated against a baseline of age based modelling which makes decisions based on asset age and does not consider asset condition, health or criticality. Benchmark DNO's benefits were calculated as the incremental savings of incorporating incremental, innovative techniques into the CBRM approach.
Oil regeneration for refurbishment	SPEN	Superseded by updated benefits calculation based on the same approach taken by the best performing DNO in this area. Original savings quantified on a different basis. Resubmission of benefits by SPEN explained that they had been revised to align calculation with other DNOs.

11.39. Where we do not accept the savings for a solution, we give the DNO the same proportion of savings in that cost category as the benchmark DNO. This does not affect the adjustment made to other DNOs.

11.40. In a small number of cases we have not received sufficient evidence that solutions are smart or innovative. The solutions for which we have insufficient evidence are detailed in Table 11.5.

Table 11.5: Claims of smart solutions with insufficient evidence

Solution	DNO	Reason for not accepting solution as smart
Perfluorocarbon tracers	NPg	Already in wide use as business as usual by other DNOs.
Mobile devices for fault response	NPg	Already in wide use as business as usual by other DNOs.
Smart solutions to benefit connecting customers (Driffield scheme)	NPg	Benefits accrue to connecting customer, not to DNO cost base.
Smart EHV schemes	NPg	Expert review indicates a lack of evidence that the schemes include a smart or innovative element.
Various smart solutions at lower voltages	NPg	Expert review indicates a lack of evidence that the expenditure reduction between fast-track and slow-track is due to smart or innovative solutions.
LV fault finding technology (eg Bidoyng, smart fuse)	All	While innovation projects have been funded in DPCR5, it is not clear how to differentiate smart from business as usual activities in this area. It would be inequitable to apply an adjustment on this basis.
Assumed smart solutions delivering ongoing efficiency	SPEN	We are only considering benefits in addition to ongoing efficiency. It is possible to forecast smart grid and other innovation savings in ex ante allowances given current information and best view of future requirements and solutions. This is distinct from ongoing efficiency, which is due to a range of factors.
Network interconnection	SPEN	Network interconnection does not provide benefits against expenditure in RIIO-ED1. For example, when reinforcement is required, an interconnected network will not be cheaper to reinforce. In contrast, we have accepted UKPN's savings from enhanced meshing. This is an innovative approach to releasing capacity at lower cost once the interconnected network requires reinforcement.

Circuit breaker retrofit	SPEN	Expert review indicates a lack of evidence that the schemes include a smart or innovative element.
Condition Based Risk Management (CBRM)	SPEN	No evidence of incremental savings in SPEN's business plan. We have accepted CBRM as a smart solution for some other DNOs. These DNOs provided evidence that they have embedded incremental savings of recent innovative developments and we have gained knowledge of their progress through annual visits. We have evidence that SPEN has not yet fully implemented CBRM. This is supported by our ongoing monitoring of DNOs' performance as well as the fact SPEN was unable to quantify the benefits of CBRM. Therefore we do not believe the incremental savings from innovative developments in CBRM are included in SPEN's business plan.

Reinforcement savings

11.41. We accept that the opportunities for savings in different areas of reinforcement may vary due in part to the different solutions that can be deployed. Therefore we have separated our assessment of benefits in reinforcement into three categories:

- LV-EHV general reinforcement
- 132kV general reinforcement
- Fault level reinforcement

11.42. We exclude expenditure on unbundling of shared services driven by thermal constraints on the service cables from LV-EHV general reinforcement. We accept that there is currently no viable alternative smart solution. Service unbundling to solve voltage issues at the substation can be avoided through the use of smart solutions. Therefore this is not excluded.

11.43. Expenditure on managing harmonics is included as we consider that there are smart and innovative alternatives to conventional reinforcement, some of which are being trialled with innovation funding.

11.44. We exclude all 132kV general reinforcement expenditure in the first two years of RIIO-ED1 from the adjustment as there is a risk these schemes are currently in progress or the design stage has already been completed. We have not reviewed all scheme papers as our cost assessment adopts a proportionate sampling approach. We note that some schemes DNOs argued should be excluded from the cut showed no sign of consideration of smart grids and are not yet fully designed. We include 132kV fault level reinforcement in the assessment as one DNO has forecast savings in this area, demonstrating that savings are achievable. We expect all DNOs to deliver these benefits.

11.45. We do not use the Transform model in our assessment in any of these categories as it is only directly applicable to a subset of LV-EHV general reinforcement. In each category we use comparative UQ benchmarking to avoid cherry-picking and to account for any possible double counting with the general cost assessment.

Savings in other cost areas

11.46. We consider that it is appropriate to use the savings identified by the best performing DNO across all cost areas outside reinforcement. This avoids issues of cherry picking by using different DNOs for different cost categories. Originally we considered setting a benchmark of 75% of the savings identified by the best performing DNO due to the risk of double counting with the cost assessment in some cost areas. The cost category where we identified a risk was in LV fault finding. We subsequently decided not to include LV fault finding solutions in our assessment. In the absence of double counting risk, we have set a benchmark at the total level of savings in other cost areas identified by the best performing DNO.

Savings from smart metering

11.47. We include the DNOs’ embedded savings in the comparative benchmarking of smart savings. We do not add a further stretch for smart metering to mitigate risks of double counting. The DNOs’ gross savings are reduced to reflect the cost of variable data over the first six years of RIIO-ED1 and the fixed and DCC licence fee costs for the last two years of RIIO-ED1, after the end of the smart meter roll out.

11.48. We expect in practice that DNOs can deliver all the benefits from smart metering that are identified in the DECC impact assessment. DNOs can and should work with suppliers to ensure smart metering delivers the greatest value for consumers at the earliest opportunity.

Allocation of smart grid savings

11.49. We accept that the allocation of savings in draft determinations did not fairly reflect the ability for DNOs to achieve them. In final determinations we allocate savings according to expenditure in each area. This better accounts for the ability of DNOs to achieve savings. For example, a DNO with a large reinforcement allowance is required to deliver higher absolute reinforcement savings than a DNO with a small reinforcement allowance.

No double counting

11.50. There is no double counting of smart grid and other innovation savings with ongoing efficiency. All DNOs have forecast smart grid savings in addition to ongoing efficiency and we are not including savings from smart grids that also form part of the ongoing efficiency assumption.

11.51. Given the level of investment consumers have made in innovation projects and the smart metering programme, we would expect savings from these in addition to historical levels of ongoing efficiency. We have no evidence that ongoing efficiency forecasts for RIIO-ED1 are significantly above those for previous price controls where these factors did not apply. We have undertaken a top-down assessment of the additional savings we are requiring DNOs to deliver. This demonstrates that the adjustment for smart grids and other innovation represents on average an additional implied frontier shift of 0.2% per year for slow-track DNOs. This compares to ongoing efficiency assumptions embedded in DNOs' business plans of between 0.8 and 1.1% per year. We consider that this additional evidence demonstrates our adjustment is appropriate and corroborates our benchmarking assessment.

11.52. We have not seen evidence of there being material double counting between the smart grids and other innovation assessment and the general cost assessment. In reinforcement any risk is mitigated by the use of UQ benchmarking in reinforcement. In other cost areas we only considered cost categories with no evidence of potential risk of double counting. We have excluded the LV fault finding cost area from our assessment because of the risk of double counting in this category.

Other

11.53. We consider it would be inappropriate to base the smart grid assessment on the level of innovation funding each DNO has received. The DNOs should be considering innovations developed by any DNO. DNOs should be working hard to ensure the learning from their own projects is shared across the industry as all consumers pay for it.

11.54. We consider an ex ante adjustment for smart grid and other innovation savings to be appropriate. An uncertainty mechanism would reduce incentives on DNOs to reduce costs and implement smart grid and other innovative solutions in the early part of the price control period.

11.55. We assessed additional information provided by DNOs to determine the smart grid benefits embedded in their business plans. We recognise that there was an incentive on DNOs to overstate the value of savings in their plans to avoid additional adjustment. To mitigate this, we have only accepted benefits that are justifiably smart and that were referenced in the DNOs' business plans.

11.56. In addition, the DNOs will be required to report against their forecast embedded benefits from each solution identified during RIIO-ED1 in the Environmental Report and Cost and Volume RIGs. DNOs will have to demonstrate that they are delivering at least the benefits they have claimed are embedded in their business plans. Stakeholders will be able to hold DNOs to account and we will be able to ensure consumers receive sufficient returns from their investments.

Smart meter IT and data costs

11.57. There are four cost categories that comprise the DNO operational smart meter costs:

- **on-site**: subject to a smart meter volume driver. A small proportion of costs are ex ante costs. The remainder is subject to an uncertainty mechanism (discussed in Chapter 9)
- **indirect IT and data services for smart meter roll out**: subject to smart meter volume driver. A small proportion of costs are ex ante costs. The remainder is subject to an uncertainty mechanism (discussed in Chapter 9)

- **ongoing smart meter IT and data services up to 2021-22:** subject to pass through (discussed here)
- **ongoing smart meter IT and data services post 2021-22**: not subject to pass through.

11.58. The costs that DNOs incur relating directly to the use of smart metering data are passed through to consumers up to 2021-22. In each DNO's ex ante allowance we include an estimate of what these smart metering IT costs might be. The DNOs will be allowed to recover the difference between their actual expenditure and this estimate, subject to an efficiency review in 2020-21. DNOs forecasting smart meter IT costs higher than the DNO group mean (£10.3m) have the requested allowance set to that of the lowest forecast (£6.9m). The adjustments are shown in Table 11.6. We took the same approach for draft determinations.

Table 11.6: Adjustments to smart meter IT and data cost allowances

DNO	Adjustment (£m)
ENWL	-6.2
NPgN	0.0
NPgY	0.0
LPN	-3.3
SPN	-3.3
EPN	-3.3
SPD	0.0
SPMW	0.0
SSEH	-0.7
SSES	-2.9

12. Real price effects and ongoing efficiency

Chapter summary

Our approach to accounting for real price effects and ongoing efficiency in our cost assessment, including changes from draft determinations.

Real price effects

Decision and results

12.1. DNOs' allowances are indexed by the Retail Prices Index (RPI) as part of the price control framework. We expect some of the costs faced by DNOs during RIIO-ED1 to change over the period at a different rate than the RPI measure of economy-wide inflation. These differences in cost changes are real price effects (RPEs).

12.2. We have retained the approach proposed in draft determinations.[45] We've included the expected impact of RPEs in the ex ante allowance for each DNO. We have reviewed the responses and latest information and updated the RPE assumption that is applied for final determinations.

12.3. A common RPE assumption is applied to all slow-track DNOs. This common assumption is derived in three stages:

1. We construct an input price trend relative to RPI for the inputs purchased by a typical DNO.
2. We weight these input price trends based on a fixed proportion of each input in each cost area.
3. We multiply this assumption by each DNOs' efficient cost allowance to derive the monetary impact of the RPE assumption.

12.4. The final determinations RPE allowance derived for each DNO is in Table 12.1.

[45] We consulted on alternative approaches and the reasons for retaining this approach can be found in the RPEs decision supplementary annex.

Table 12.1: Value of RPE assumption over RIIO-ED1

DNO	RPE allowance (£m)	Requested RPE allowance (£m)
ENWL	5	82
NPgN	3	63
NPgY	4	85
LPN	4	78
SPN	4	75
EPN	6	113
SPD	4	68
SPMW	4	86
SSEH	3	39
SSES	6	82

Constructing an input price trend

12.5. We forecast the impact of RPEs for the inputs general labour, specialist labour, capex materials, opex materials, and plant and equipment. For all other costs we have assumed their price will change in line with economy-wide inflation.

12.6. We first select relevant available input price indices that represent these inputs. Table 12.2 shows the indices used for final determinations. Then for each input we derive an RPE assumption for each year from the base year to 2022-23, the last year of RIIO-ED1. Our approach to forecasting input price trends uses the following methodology for each year:

- 2013-14 is our base year and therefore the first year an RPE assumption is applied is 2014-15. This is the base year because our cost assessment uses DNOs' actual costs including RPEs for this year.
- For 2014-15 we use the actual input price index and RPI data available so far for this year.
- For labour input price trends we use a short-term forecast for 2015-16. We use the consensus forecast published in the October 2014 edition of the HM Treasury Forecasts for the UK Economy.[46] Given that this forecast is for the whole economy we add 0.15% to reflect that a DNO is a private sector organisation.
- For all other inputs from 2015-16, and for labour from 2016-17, we use the average historical real growth in indices as our RPE assumption. We use input price index data for c. 16 years and use data up to and including 2013-14 to construct the historical average.
- For each year we make an adjustment to account for the step-change in RPI.

12.7. Table 12.2 shows the input price indices we are using for our final determinations RPE assumption.

[46] See 'New (marked *)' forecasts in: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/363808/Forecomp_201410.pdf

Table 12.2: Input price indices[47]

Source	Index	Historical series	Historical average real growth rate[48]	Real growth rate in 2014-15[49]
ONS	CHAW Retail Prices Index	1987-2014	NA	2.4%
General labour				
ONS	LNKY AEI private sector including bonus	1990-2000	0.7%	NA
ONS	K54V AWE private sector including bonus	2000-2014		-1.9%
Specialist labour				
BEAMA	Electrical labour	1987-2014	1.6%	1.7%
BCIS	70/1 Labour and supervision in civil engineering	1987-2014	1.1%	-1.1%
Capex materials				
BCIS	3/58 Copper pipes and accessories	1991-2014	1.7%	-5.8%
BCIS	3/59 Aluminium pipes and accessories	1991-2014	0.3%	-2.4%
BCIS	3/S3 Structural steelwork materials: civil engineering work	1991-2014	1.5%	-4.4%
Opex materials				
BCIS	FOCOS RCI infrastructure: materials	1990-2014	1.6%	-0.7%
Plant and equipment				
ONS	K389 Machinery and equipment output PPI	1996-2014	-1.2%	-1.2%
BCIS	70/2 Plant and road vehicles: providing and maintaining	1987-2014	-0.2%	-1.8%

12.8. We have applied an adjustment to account for the RPI step-change in 2010.[50] In rolling forward the historical average real growth rates into the future, we are assuming that the gap between economy-wide inflation and inflation for DNO inputs will be consistent with the gap in the past. As RPI experienced the step-change in 2010, this will no longer be the case and therefore it is necessary to make an adjustment to the forecast. If no adjustment is made, DNOs would receive an additional RPE in the RPI up-rating.

12.9. The adjustment for the RPI step-change is a two stage process:

- We subtract 0.4% from RPI for 2010-11 to 2014-15 before calculating the real input price index. The same adjustment must be made to the forecast for RPI used in calculating the real short-term labour forecast in 2015-16.
- We subtract 0.4% from the input price trend for each year to remove the additional 0.4% per year growth in RPI DNOs will receive through RPI indexation.

12.10. Table 12.3 shows the resulting input price trends.

[47] These figures are before any adjustment for the RPI step-change.
[48] We use data up to and including March 2014.
[49] These growth rates are extrapolated from the data for the year so far, c. 5 to 7 months. This assumes the growth experienced to date will continue for the remainder of the year.
[50] During 2010 the Office of National Statistics changed the way it calculates price increases for some items that make up the RPI measure of economy-wide inflation. This led to an increase in RPI relative to underlying cost inflation. Further information can be found in Appendix 8 of our final determinations overview.

Table 12.3: Input price trends

	2013-14	2014-15	2015-16	2016-17 to 2022-23
General labour	-	-1.9%	-0.5%	0.4%
Specialist labour	-	0.3%	-0.5%	1.0%
Capex materials	-	-4.2%	0.8%	0.8%
Opex materials	-	-0.7%	1.3%	1.3%
Plant and equipment	-	-1.5%	-1.0%	-1.0%
Other	-	-0.4%	-0.4%	-0.4%

Weighting together the input price trends

12.11. The inputs are weighted into six cost areas using a notional structure. The notional structure equals the average of slow-track DNOs' business plan submissions. Table 12.4 shows the notional structure applied.

Table 12.4: Notional structure

	General labour	Specialist labour	Materials (capex)	Materials (opex)	Plant and equipment	Other
Load-related capex	21%	32%	37%	-	6%	5%
Non load-related capex – asset replacement	21%	39%	29%	-	7%	5%
Non load-related capex – other	22%	35%	30%	-	8%	5%
Faults	37%	36%	9%	7%	6%	6%
Tree cutting	85%	4%	-	4%	2%	5%
Controllable opex	51%	23%	-	9%	5%	13%
Totex	36%	31%	16%	4%	6%	8%

12.12. Table 12.5 shows the totex RPE assumption which is derived from multiplying the input price trends in Table 12.3 by the totex weights in Table 12.4.

Table 12.5: Totex RPE assumption

	2013-14	2014-15	2015-16	2016-17 to 2022-23
Totex	-	-1.4%	-0.3%	0.6%

Draft determinations approach

12.13. For draft determinations our approach was very similar. An RPE assumption was applied from 2012-13 to the end of RIIO-ED1. We chose a set of input price indices that represented the inputs DNOs purchased. We calculated the real input price trend for each input and applied the actual change in these indices for 2013-14 and then applied the historical average. We also incorporated a short-term forecast for wage growth for 2014-15 and 2015-16. We took account of the RPI step-change in deriving the assumption.

12.14. Our assessment of RPEs resulted in an £850m cut to the totex allowances requested by the slow-track DNOs.

Responses

12.15. All slow-track DNOs considered that our draft determinations were inadequate and would not protect them against the risk of their costs increasing above economy-wide inflation over RIIO-ED1. On the other hand a supplier welcomed the cost reductions we proposed, but considered that further cuts would not be unreasonable. We received a number of specific comments from the DNOs which are explained below.

Labour

12.16. DNOs considered that the labour RPE assumption for 2012-13, which was calculated based on actual data, did not represent the cost pressures they faced that year. They also argued that the short-term labour forecast was not appropriate as it represented the whole economy and they are private sector organisations. Therefore an uplift should be applied to the forecast to account for the wage growth differential experienced in recent years. DNOs also argued that there should be an additional premium applied to the forecast as it did not appropriately reflect the specialist nature of some of their labour force.

12.17. DNOs suggested that in the short–term we should use additional evidence to derive the labour RPE including their own pay deals and the ONS' Annual Survey of Hours and Earnings (ASHE) dataset.

12.18. One DNO raised concern that the data we were relying on was unrepresentative. It presented evidence from the ONS' ASHE dataset that showed that people in continuous employment (employed in the same job for at least 12 months) have higher wage growth than others. DNOs also made reference to the recession's impact on employment patterns and that this may have skewed the data in a way that did not represent change in their own workforce.

12.19. One DNO argued that its proportion of specialist labour, when compared to general labour, was higher than the weight we applied in draft determinations. It noted that DNOs provided information on staff numbers by Standard Occupational Classification (SOC) code for the calculation of the regional labour normalisation and that this evidence suggested DNOs employ a higher proportion of specialist labour.

Alternative forecasting methods

12.20. The slow-track DNOs proposed an alternative method of forecasting the impact of RPEs - by using ARIMA modelling. They argued that this method would better reflect a return to the long-term trend from the current below trend position of most cost indices.

12.21. They suggested that we should also take account of the Competition Commission's (CC) approach in its determination for Northern Ireland Electricity (NIE) in finalising our approach to RPEs. DNOs' analysis suggested that RPE allowances would be higher than we proposed if the CC approach was followed and that therefore our allowances may be viewed as too low.

12.22. Some DNOs also considered that we had materially changed our approach from that used at previous RIIO price control reviews and that these changes had not been justified.

RPI step-change

12.23. DNOs argued that there was limited evidence to support an adjustment for the RPI step-change. However, they argued that if we consider an adjustment to be appropriate it should be 0.15% per year as opposed to our assumption of 0.4% per year. The value of 0.15% was reached by calculating the difference between RPI and RPIJ[51] and then, based on the uncertainty around whether an adjustment should be made, halving this figure. The DNOs argued that there have been a number of changes to the RPI methodology in the past and therefore it's selective to only adjust for one. DNOs also considered that no adjustment should be applied to transport and other costs because these are assumed to vary with RPI.

Regional RPEs

12.24. A DNO presented new evidence that some input costs may grow faster in London and the South East than elsewhere in Great Britain. In its view a higher labour RPE assumption should be allowed for DNOs operating in London and the South East. It presented evidence that suggested the market for the majority of inputs was national but there was expected to be regional difference in the growth in contractor tender prices.

Relevant base year

12.25. A number of DNOs argued that the RPE base year should now be 2013-14 because we have actual cost data for 2013-14 which includes the impact of RPEs.

Choice of input price indices and time periods

12.26. One DNO argued that using an input producer price index to represent plant and equipment costs was not relevant because DNOs don't purchase manufacturing inputs. DNOs argued that we should use longer datasets for the indices where data was available.

[51] RPIJ is a measure of inflation published by the ONS. It is an improved variant of RPI, correcting for one of the changes made to RPI in 2010. For more information see the ONS' Introducing the new RPIJ measure of consumer price inflation (2013): http://www.ons.gov.uk/ons/rel/cpi/introducing-the-new-rpij-measure-of-consumer-price-inflation/1997-to-2012/index.html

Errors

12.27. A number of DNOs noted that we did not properly recognise UKPN's split between general and specialist labour in the notional structure. An error was also identified in how the RPI forecast was calculated.

Reasons for our decision

Labour

12.28. There is evidence that there will be a difference between public and private sector wage growth in the short-term. Economy-wide wage growth has, on average since 2011-12, been around 0.15% a year lower than private sector wage growth. Therefore using an economy-wide forecast for 2015-16 may under-compensate DNOs for the labour cost pressures they will face. We have therefore added 0.15% to the forecast for labour that we apply in 2015-16.

12.29. For the majority of the time period we use different evidence to derive RPE assumptions for specialist and general labour. In doing so we recognise that specialist staff's wages have the potential to grow at a faster rate than general staff. At draft determinations, for the years where an independent forecast was used to derive the RPE assumption, we applied the same assumption to general and specialist labour. We still consider this to be appropriate.

12.30. Historically specialist labour costs have increased faster than general labour costs. However, for 2015-16, the only year where the RPE assumption is the same for general and specialist labour, we think there is uncertainty as to whether such a premium exists. Recent years' data suggests that the premium experienced over the long-term should not be applied. In addition, BEAMA's own forecast for its engineering labour index suggests that growth will remain below inflation over the next three years.

12.31. We consider that no adjustment is needed to account for the evidence presented by a DNO that those in continuous employment receive higher wage growth. DNOs have not provided evidence that they have a higher proportion of continuously employed staff than the wider economy. More broadly, we recognise that structural changes to the labour market, particularly over recent years, have had an impact on the make-up of labour input price indices but DNOs have not put forward a compelling case on why they may have been impacted differently from the wider private sector or quantified the impact.

12.32. We have not changed the evidence used to derive our labour RPE assumptions. We recognise that other evidence exists but consider the indices we have chosen to be robust and representative of the wage growth that a company like a DNO may face. The RPE assumption is not intended to match the costs that DNOs will, or have actually, faced. Rather it is intended to reflect the external pressures on costs, relative to economy-wide inflation, that are outside of their control. We therefore consider it inappropriate to factor DNOs' own pay deals into the RPE assumption. To do so could amount to consumers paying for inefficient pay deals. We also note that a proportion of each DNO's labour force is contractors and they would not be subject to the DNOs' pay deals.

12.33. We have updated the notional structure applied to correct for our error in missing some information from UKPN. We have not made any further changes. We think it would be inappropriate to use data submitted for another purpose as proposed by a DNO. There are differences in the weights DNOs apply to each input including the split of specialist and general labour. However, the evidence presented by DNOs to support their specialist labour RPE assumptions is similar and therefore we have to assume that DNOs made accurate assumptions of the split when submitting their business plans.

Alternative forecasting methods

12.34. The DNOs proposed an alternative method for forecasting RPEs using a modelling technique known as ARIMA. We recognise the benefits that ARIMA modelling could bring. However it also requires a level of subjectivity in the choice of assumptions put into it. For this reason we don't think it would be suitable for us to use this approach at this stage in the price control review.

12.35. The DNOs noted that our approach was not the same as the CC's in its NIE determination. In our view the key difference are that the CC uses:

- average historical nominal growth rates and then subtracts a forecast of RPI
- NIE's own weights between cost areas (noting that the CC did this because there were no comparator companies)
- other sources of information
- the same RPE assumption for all labour, ie no specialist labour premium is included
- the Office of Budget Responsibility's forecast for short-term wage growth.

12.36. As with any forecast there is a risk that it will not match outturn costs. We have examined other regulators' approaches including the CC and consider that our approach is well justified and creates the right balance of risk between DNOs and consumers.

12.37. We do not agree that we have materially changed our approach to forecasting the impact of RPEs from that used at RIIO-GD1 and T1. The approach taken is broadly the same and where there are changes there is a reason for doing so. These changes are:

- Use of input price indices that reflect the inputs DNOs purchase and use of the latest actual and forecast data. Some of the inputs purchased by DNOs differ to those purchased by gas distribution networks or transmission operators.
- Use of data for the years up to and including 2013-14 when constructing the long-term average. At RIIO-GD1 and T1 we did not include data beyond 2009-10 in the historical average. For RIIO-ED1 we think it is right to use the longest possible data period.
- Application of an adjustment to account for the step-change in RPI in 2010. Having undertaken further analysis we think it is appropriate to apply this adjustment. This is consistent with the treatment of the cost of equity for RIIO-ED1.

RPI step-change

12.38. We still consider that accounting for the step-change in RPI is necessary and that the proposed magnitude is appropriate. Principally, the adjustment is needed because otherwise we would over-compensate DNOs for the impact of inflation in the cost of goods and services they purchase. The value of the adjustment relates to our estimate of the structural change in RPI inflation relative to real world prices, as we describe in Appendix 8 to the overview document.

12.39. The DNOs argued that we should use the difference between RPI and RPIJ to calculate the magnitude of the adjustment. This ignores the fact that a number of changes were made to RPI and CPI only one of which is 'corrected' in the RPIJ measure. We recognise that the RPI methodology is changed regularly but note that the ONS considers these to be of lower materiality.

12.40. We do not derive a separate RPE assumption for other costs because we assume them to move in line with economy-wide inflation. RPI is currently over-estimating economy-wide inflation. With no adjustment to the RPE for other costs, we would be assuming these costs increase at a rate higher than economy-wide inflation.

Regional RPEs

12.41. We have not applied regional RPE assumptions because we consider the evidence that there will be a difference between regions over RIIO-ED1 to be weak. The DNO has not provided evidence that the forecasts of contractor tender costs are relevant to the DNOs. Higher margins should encourage new entrants into the contractor market, increasing competition and reducing prices. DNOs have a high degree of control over their labour force and the use of contractors. They can in-source activities to avoid paying inflated contractor margins or can encourage new contractors into the market.

12.42. DNOs in London and the South East receive additional allowances to reflect the higher cost of operating in these areas.

Relevant base year

12.43. The RPE assumption must be applied from a base year because it represents the expected movement in costs from this base year, relative to RPI. We have moved the base year from 2012-13 to 2013-14. We have done this because our cost benchmarking uses actual data for 2013-14 which includes RPEs. There is a risk of double counting the impact of RPEs if we do not adjust the base year.

Other changes

12.44. We have updated all data used to construct the RPE assumption since draft determinations. There were some minor revisions to historical data which result in changes to historical averages. We have also decided to use outturn data for 2014-15 because we consider this represents the near-term impact of RPEs better than a forecast or the historical average growth rate. We also note that the forecast for wage growth for

2014-15 is not materially different from what outturn data is showing for the year to date.

12.45. We no longer use the input producer price index in the RPE assumption for plant and equipment costs as we agree that it may not best represent the inputs DNOs purchase.

12.46. We have not extended the period used to calculate the historical average growth rates. We prefer to apply a relatively consistent time period to calculate all historical average growth rates. Generally we have taken a period of c. 16 years for all indices and longer data was only available for four indices.

12.47. We have corrected the errors identified.

Ongoing efficiency

Decision and results

12.48. We expect even the frontier DNO to make productivity improvements over the price control period, for example by employing new technologies. These improvements are captured by the ongoing efficiency assumption. This assumption represents the potential reduction in input volumes that can be achieved whilst delivering the same outputs.

12.49. We have not made any changes from draft determinations. An ongoing efficiency assumption of between 0.8 and 1.1% per year is included in each DNO's cost allowance.

Draft determinations approach

12.50. All DNOs included an ongoing efficiency assumption in the costs they submitted in their business plans. Assumptions varied marginally between DNOs. We assessed them as all being in line with our view of the savings an efficient company could make. Therefore we proposed no adjustment to DNOs submitted cost allowances. These efficiencies were in addition to smart grid savings included in draft determinations.

Responses

12.51. There was limited challenge to the proposed ongoing efficiency assumptions. Comments focused on the relationship between ongoing efficiency and RPEs and that a negative net impact of the two was inappropriate because it was a result of cherry picking a low RPE and high productivity assumption. Some felt that assessing ongoing efficiency separately from RPEs failed to recognise that higher RPEs drove higher productivity. One DNO also suggested that the RPI adjustment applied to RPEs should apply in an equal and opposite direction to the ongoing efficiency assumption.

Reasons for our decision

12.52. We do not agree that higher productivity improvements can only be achieved by providing cost allowances that potentially over compensate DNOs for the input price inflation they will face. The RPE assumption protects DNOs from expected input price inflation that is outside of their control. We think the RPE and ongoing efficiency assumptions reflect what an efficient DNO can achieve. It is up to each DNO to balance the price it pays for its inputs against the productivity improvements achievable by these inputs. We don’t agree that an adjustment should be made to the ongoing efficiency assumption to account for the RPI step-change. The information we have used to assess what an efficient DNO’s productivity improvements could be over RIIO-ED1 is independent of RPI.

12.53. A number of DNOs also raised concerns that including both smart grid savings and an ongoing efficiency assumption would result in a double count of the savings they could achieve. We discussed this point in relation to smart grid savings in Chapter 11.

Appendices

Appendix 1 – RIIO-ED1 totex and disaggregated modelled costs

The table below details our modelled slow-track draft determinations post IQI for each DNO at the totex level and for each disaggregated activity.

Table A.1: Totex and disaggregated modelled costs (£m, 2012-13 prices)

	ENWL	NPgN	NPgY	LPN	SPN	EPN	SPD	SPMW	SSEH	SSES	Total slow-track DNOs
Connections	27.1	6.1	8.2	11.2	20.7	45.0	3.9	21.8	22.8	17.6	184.3
Diversions	28.4	24.0	33.6	29.3	58.2	104.5	10.8	21.8	4.1	59.1	373.9
Reinforcements	101.8	83.4	91.9	299.6	173.1	301.3	128.7	144.3	56.0	211.2	1,591.3
TCP	6.3	9.3	0.0	41.3	22.5	14.2	8.0	0.0	52.2	4.4	158.2
ESQCR	5.0	0.0	0.0	0.0	23.3	37.1	54.7	60.3	2.5	0.0	182.8
Asset replacement	367.0	270.6	336.1	251.3	265.7	360.9	231.4	375.6	180.4	454.3	3,093.2
Refurbishment	103.2	50.3	66.3	14.4	22.6	27.8	44.8	59.3	29.1	86.9	504.7
Civil works	82.8	31.1	55.3	45.5	56.4	84.5	48.2	58.5	19.5	45.8	527.6
Op IT & Telecoms	52.0	22.7	40.3	44.0	32.0	42.5	21.1	30.5	16.9	32.9	334.7
Legal & safety	38.5	23.4	53.7	58.2	41.8	52.6	24.1	36.4	4.3	23.5	356.5
QoS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HVP	0.0	0.0	10.7	87.8	29.0	21.4	0.0	0.0	0.0	26.4	175.3
Flooding	10.6	16.5	21.5	3.7	3.8	7.4	0.8	0.7	0.6	19.8	85.5
BT21CN	0.0	0.0	0.0	0.0	11.8	15.9	3.9	21.0	1.8	4.0	58.4
Technical loss & environmental	13.6	2.1	3.4	5.4	7.7	12.7	17.6	14.8	5.9	18.6	101.8
Critical National Infra	0.0	0.0	1.4	0.5	1.1	1.8	0.0	1.8	0.0	0.0	6.7
Black Start	8.1	3.1	5.1	1.9	3.9	5.3	1.7	4.2	4.0	1.7	39.1
Rising Mains & Laterals	14.6	3.0	4.4	0.0	16.1	9.3	82.5	37.5	2.6	7.4	177.3
Troublecall	160.5	132.3	216.2	139.7	147.1	222.2	141.9	109.5	99.4	205.4	1,574.3
ONIs	31.9	32.4	66.7	38.3	37.0	61.3	39.6	37.3	8.4	57.7	410.5
SW 1-20	3.3	8.4	7.4	0.0	4.2	8.3	4.3	4.1	6.9	7.9	54.7
I&M	59.7	42.8	60.1	114.6	64.5	101.9	52.6	63.6	34.7	104.5	699.1
Tree cutting	34.8	32.5	38.4	0.1	58.6	123.6	54.8	83.9	58.6	102.7	588.0
NOCs other	14.6	7.6	14.5	21.0	16.8	34.6	16.7	12.1	52.6	8.2	198.6
CAI	361.0	239.1	295.8	320.3	345.3	497.5	298.1	286.9	241.0	488.0	3,373.0

Smart meters	13.0	10.5	14.7	14.0	13.6	21.5	12.5	8.0	4.2	17.0	128.9
Business support	235.4	153.2	174.9	176.8	183.2	228.2	164.9	129.7	155.1	247.4	1,848.8
Non op capex	51.6	60.6	73.7	51.4	62.3	93.2	51.8	43.3	37.7	82.2	607.8
Improved resilience	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.1	0.0	20.1
Totex	**1,825.0**	**1,264.8**	**1,694.3**	**1,770.6**	**1,722.4**	**2,536.3**	**1,519.4**	**1,666.7**	**1,121.3**	**2,334.5**	**17,455.1**

Appendix 2 - Disaggregated model key results

Key finding from our disaggregated analysis for each of the ten DNOs subject to our slow-track assessment. It provides the greatest detail on areas where the difference between our modelled costs and the DNOs' submitted costs are greatest. The numbers in the narrative are based on the net modelled costs, post reversal of adjustments, prior to combining with the totex models and prior to application of the UQ, RPEs, smart grid savings and interpolation under the IQI. The description of the cuts on asset replacement is based on normalised data.

ENWL

Reinforcement

A2.1 ENWL benchmarks well on reinforcement. It ranks 4th of the ten slow-track DNOs, with our modelled costs £4m or 4% above its forecast costs. Our model suggests no reductions to its submitted volumes, with a small positive adjustment to its volumes for LCT related reinforcement.

A2.2 It has relatively high unit costs associated with primary network reinforcement but these are more than offset by low costs for secondary network reinforcement. We are making no adjustments to TCP charges.

Connections

A2.3 ENWL ranks 7th of the ten slow-track DNOs on connections. Our modelled costs are £5m or 16% lower than its forecasts.

Asset replacement

A2.4 ENWL benchmarks well on most asset replacement volumes for the majority of asset categories. It ranks 4th of the ten slow track DNOs. Our modelled costs are £15m or 4% lower than its submitted costs.

A2.5 Our view of LV switchgear volumes is slightly lower than ENWL's forecast. This takes into account a qualitative adjustment for LV metered cut outs where in our modelling we were making a negative adjustment. A review of ENWL's supporting narrative suggested higher volumes were justified, so our reduction was scaled back.

A2.6 Our view of pole-mounted 6.6/11kV switchgear volumes is lower than ENWL's forecast because no justification was provided for this and it is unclear what is driving the volumes submitted. We scaled back our negative adjustment to 6.6/11kV RMUs following a cross check with the asset health and criticality secondary deliverables. We also applied a qualitative adjustment to scale back our modelled negative adjustment for ground mounted transformers.

A2.7 Our modelled view of ENWL’s 132kV fixtures and fittings volumes is significantly lower than ENWL’s forecast and ENWL has provided insufficient justification to support the difference.

A2.8 ENWL has relatively high asset replacement unit costs for a number of categories including underground LV cables and services, LV switchgear, EHV towers, EHV poles and conductors and 132kV switchgear and transformers.

Refurbishment

A2.9 ENWL ranks 6th of the ten slow-track DNOs for refurbishments costs. Our modelled costs are £12m or 11% lower than ENWL’s forecast costs. This is largely because of its high 132kV tower refurbishment costs.

Civil works

A3.1 ENWL benchmarks relatively well on civil works with our modelled costs £9m or 12% higher than its forecasts. It ranks 4th of the ten slow-track DNOs. It is efficient on unit costs and this more than outweighs any negative volume adjustments.

Non-core network investment

A2.10 ENWL performs poorly in this area. Our modelled view of ENWL’s non-core costs is £15m or 8% lower than its forecast. It ranks 9th out of the ten slow track DNOs. This is largely due to the difference in our modeled costs and ENWL’s submitted costs for operational IT&T. Our consultants consider expenditure for control centre hardware and software significantly higher than benchmarked costs.

Network operating costs (NOCs)

A2.11 ENWL benchmarks well overall on NOCs with low costs for troublecall and tree cutting more than offsetting high costs for ONIs.

Closely associated indirects (CAI)

A2.12 ENWL is the frontier DNO on CAI costs and our modelled view is £49m or 15% higher than its submitted forecasts. It is efficient for the regressed sub-categories of CAI costs.

Business support and non-op capex

A2.13 Our efficient view of ENWL's costs is slightly lower than its forecast expenditure for business support. This is £2m or 1% of its total cost forecast. While it is the least efficient DNO in this area this is in the context of a very small adjustment to its costs.

A2.14 ENWL is the most efficient DNO on non-op capex. Our view of efficient costs is £17m or 45% higher than its submitted costs. Its relatively low costs for vehicles and transport and property more than compensate for relatively high costs for non-op capex IT&T.

NPgN

Reinforcement

A2.15 NPgN is one of the least efficient on reinforcement, with our modelled costs £14m or 14% lower than submitted forecasts.

A2.16 Our modelled view of NPgN's volumes for LCT related network interventions is lower than its forecast. The difference is more than offset by positive unit cost and qualitative adjustments (following a separate assessment of unlooping of shared services). There are no adjustments to our modelled volumes elsewhere in other reinforcement areas.

A2.17 It has relatively high unit costs associated with primary network and secondary network reinforcement, while it has relatively low unit costs for fault level reinforcement. For secondary network reinforcement (non-LCTs) we are applying a positive qualitative adjustment to our modelled view due to NPgN's relatively low unit cost for MVA of capacity. On fault level reinforcement we are applying a positive qualitative adjustment to our model view based on the technical review of specific scheme. We are making no adjustments to TCP charges.

Connections

A1.1 NPgN benchmarks well on connections with our modelled costs £2m or 41% higher than its forecasts. It ranks 2nd of the ten slow-track DNOs. This includes a £1.6m adjustment due to their losses reduction strategy on LV main (UG) plastic cables discussed in Appendix 7. If this adjustment was excluded then they would be £0.2m or 4% higher than their forecasts.

Asset replacement

A2.18 NPgN ranks 3rd of the ten slow-track DNOs in asset replacement. Our view is £10m or 4% lower than its forecast costs.

A2.19 NPgN benchmarks well on asset replacement volumes for the majority of asset categories.

A2.20 We applied a volume reduction to pole mounted HV switchgear in our modelled view due to NPgN's comparatively high replacement volumes. Our consultants conducted a review and found that a significant amount of NPgN's HV switchgear had been replaced in the last ten years and it should not require such replacement volumes. We applied a qualitative adjustment to scale back our modelled reductions for 20kV.

A2.21 We scaled back reductions to our modelled view of 33kV pole volumes following a cross check with the asset health and criticality secondary deliverables. We also applied a qualitative adjustment to scale back our modelled reductions for indoor LV pillars and 66kV non-pressurised underground cable following assessment work on smart enablers.

A2.22 NPgN has relatively high asset replacement unit costs for a number of categories including underground LV cables and services, HV switchgear, EHV towers, EHV switchgear and transformers. Adjustments have been made to NPgN's submitted unit costs following a review undertaken surrounding smart enablers. These adjustments were made to indoor LV pillars and 33kV non-pressurised cable.

Refurbishment

A2.23 NPgN ranks 9th of the ten slow-track DNOs for refurbishments costs. Our modelled costs are £17m or 27% lower than forecast costs. Its volumes for EHV and 132kV transformers are comparatively high. It also has high HV pole refurbishment unit costs.

Civil works

A2.24 NPgN benchmarks relatively poorly on civil works with our modelled costs £10m or 26% lower than its forecasts. It ranks 8th of the ten slow-track DNOs. The key reasons for this are the adjustments in both volumes and unit costs for plinths and groundworks at EHV substations (for work driven by asset replacement).

A2.25 For HV substation work driven by condition we make a positive qualitative adjustment to indoor substation volumes, following our technical consultants' review. The submitted volumes are significantly lower than historical rates, and NPg have presented a credible case.

Non-core network investment

A2.26 Our view of NPgN's non-core costs is £3m or 4% lower than its forecast. It ranks 7th of the ten slow track DNOs. Our model suggests inefficiencies can be made for diversions, legal and safety, flood resilience and black start costs.

Network operating costs (NOCs)

A2.27 NPgN benchmarks poorly on NOCs, ranking last of the ten DNOs. Our modelled costs are £41m or 14% lower than its forecast costs. This is largely driven by high costs in troublecall and ONIs.

Closely associated indirects

A2.28 NPgN benchmarks well on CAI costs, ranking 4th of the ten slow-track DNOs. Our modelled view is £6m or 3% higher than its submitted forecasts. The difference between our modelled and NPgN's submitted wayleaves costs (because of high unit costs) are more than compensated for by efficient costs in all other regressed CAI categories.

Business support and non-op capex

A2.29 NPgN is one of the frontier DNOs for BSCs. Our modelled costs are £23m or 18% higher than NPgN's forecast costs.

A2.30 NPgN is also one of the most efficient DNOs on non-op capex. Our modelled costs are £3m or 6% higher than NPgN's forecast costs.

NPgY

Reinforcement

A2.31 NPgY benchmarks relatively poorly on reinforcement. It ranks 7th of the ten slow-track DNOs, with our modelled costs £8m or 8% lower than submitted forecasts.

A2.32 Our modelled view of NPgY's volumes of LCT related network interventions is lower than its forecast. The difference is partially offset by positive unit cost and qualitative adjustments (following a separate assessment of unbundling of shared services). Our modelled view of volumes in other areas shows no significant differences.

A2.33 It has relatively high unit costs associated with n-1 primary network reinforcement and other work captured in the load index secondary deliverables, while it has relatively low unit costs for fault level reinforcement and LCT reinforcement. We are making a positive qualitative adjustment for secondary reinforcement (non-LCTs) to reflect its low unit costs per MVA of capacity.

A2.34 We are making no adjustments to the forecast costs for TCP charges.

Connections

A1.2 NPgY is the frontier DNO on connections with our modelled costs £3m or 54% higher than its forecast. This includes a £2.4m adjustment due to their losses reduction strategy on LV main (UG) plastic cables discussed in Appendix 7. If this adjustment was excluded then they would be £0.5m or 9% higher than their forecasts.

Asset replacement

A2.35 NPgY ranks 6th of the ten slow track DNOs in asset replacement. Our modelled costs are £28m or 8% lower than its forecast costs.

A2.36 Our modelled view of LV cables is lower than NPgY's forecast due to high replacement volumes in comparison to historical volumes.

A2.37 NPgY's pole-mounted HV switchgear replacement volumes are high compared to our modelled view. Our consultants conducted a review and found that a significant amount of NPgY's HV switchgear had been replaced in the last ten years and it should not require such replacement volumes. We also applied a qualitative adjustment to scale back our modelled negative adjustment for 6.6/11kV RMU's as our consultants suggested that higher volumes were justified.

A2.38 We scaled back the negative adjustments of our modelled view of EHV poles and switchgear following a cross check with the asset health and criticality secondary deliverables. We also applied a positive qualitative adjustment to our modelled view of indoor and outdoor LV pillars at substations following assessment work on smart enablers.

A2.39 NPgY has relatively high asset replacement unit costs for a number of categories including underground LV cables, HV poles and switchgear, EHV conductor, switchgear and transformers, 132kV towers and switchgear. Adjustments have been made to NPgN's submitted unit costs due to the review undertaken surrounding smart enablers. These adjustments were made to indoor and outdoor LV pillars and 33kV non-pressurised cable.

Refurbishment

A2.40 NPgY ranks 8th of the ten slow-track DNOs for refurbishments costs. Our modelled costs are £19m or 25% lower than forecast costs. We think NPgY refurbishment volumes for EHV and 132kV transformers are too high. NPgY benchmarks comparatively poorly due to its high HV pole refurbishment costs. NPgY also benchmark poorly due to its comparatively high tower painting costs.

Civil works

A2.41 NPgY benchmarks relatively poorly on civil works with our modelled costs £17m or 25% lower than its forecasts. It ranks 7th of the ten slow-track DNOs. As with NPgN, the key reason for the differences are the volumes and unit costs for plinths and groundworks at EHV substations (for work driven by asset replacement), which are high relative to our benchmark.

A2.42 For NPgY we make a positive qualitative adjustment for HV indoor substation volumes. The submitted volumes are significantly lower than historical rates, and NPg have presented a credible case.

Non-core network investment

A2.43 NPgY ranks 6th of the ten slow-track DNOs for non-core non-load-related expenditure. Our modelled view is £4m or 3% lower than NPgY's forecast costs. This is largely explained by legal and safety costs being £5m higher than our modeled costs. Like NPgN this is driven by particularly high unit costs for asbestos management: meter positions and high fire protection unit costs.

Network operating costs (NOCs)

A2.44 NPgY benchmarks poorly on NOCs (9th of the ten slow-track DNOs). Our modelled view is £36m or 8% lower than NPgY's forecast costs. This is largely driven by high costs in troublecall, ONIS and tree cutting.

Closely associated indirects

A2.45 NPgY is one of the most efficient DNOs on CAI costs ranking 3rd of the ten slow-track DNOs. Our modelled view is £29m or 11% higher than its submitted forecasts. NPgY is efficient across all of the regressed sub-categories of CAI costs.

Business support and non-op capex

A2.46 NPgY is one of the frontier DNOs for BSCs. Our modelled costs are £27m or 17% higher than NPgY's forecast costs.

A2.47 NPgY is one of the most efficient DNOs on non-op capex costs, ranking 2nd of the ten slow-track DNOs. Our modelled costs are £7m or 10% higher than NPgY's forecast costs.

LPN

Reinforcement

A2.48 LPN benchmarks poorly on reinforcement. It ranks 8th of the ten slow-track DNOs, with our modelled costs £41m or 12% lower than its submitted forecasts.

A2.49 It benchmarks poorly on capacity added relative to maximum demand growth for n-1 primary network reinforcement and other work captured in the load index secondary deliverables, but we are applying a qualitative adjustment to close 80% of the gap based on the strength of its scheme papers. It benchmarks well on unit costs associated with this work.

A2.50 Our modelled view applies a reduction to submitted volumes for LCT related network interventions. This reduction is partially offset by an increase to its unit costs as they are below the industry median. We are applying no other volume adjustments.

A2.51 We are applying a small increase to submitted unit costs for other primary reinforcement and a large reduction to our view of costs for secondary reinforcement (non-LCTs). We are making no adjustments to TCP charges.

Connections

A1.3 LPN ranks 6th of the ten slow-track DNOs for connections. Our modelled costs are £2m or 14% lower than LPN's forecast costs.

Asset replacement

A2.52 LPN benchmarks poorly on asset replacement ranking 9th of the ten slow-track DNOs. Our modelling is £57m or 19% lower than forecast costs.

A2.53 LPN benchmarks well on asset replacement volumes for the majority of asset categories but unit costs are high.

A2.54 We applied an adjustment to our modelled view of EHV circuit breakers as our consultants suggested that higher volumes were justified. We also adjusted our modelled view of 33kV switchgear following a cross check with the asset health and criticality secondary deliverables.

A2.55 LPN has high asset replacement unit costs for a number of categories including underground LV switchgear, HV cable, EHV cable and 132kV cable, switchgear and transformers.

Refurbishment

A2.56 LPN is one of the frontier companies of the ten slow-track DNOs for refurbishments costs. LPN is in line with our modelled view and benchmarked very well on 132kV protection refurbishment costs.

Civil works

A2.57 LPN is the most inefficient DNO with our modelled view £31m or 45% lower than its forecast costs. Our modelled view is lower in most of the civil works cost activities, with the largest negative unit cost adjustment for cable tunnels. For LPN this is a reflection of the volume reductions for substation works and relatively high unit costs for cable tunnels.

Non-core network investment

A2.58 LPN is the frontier of the ten slow-track DNOs for non-core non-load-related expenditure. Our modelled costs are £20m or 15% higher than LPN's forecast costs. This is driven largely by differences between our modelled and LPN's forecast costs in legal and safety. LPN's site security costs are particularly efficient.

Network operating costs (NOCs)

A2.59 LPN is among the most efficient DNOs for NOCs. Our modelled view of costs is £2m or 1% higher than LPN's forecast costs. Differences in costs in troublecall and inspection and maintenance account for this.

Closely associated indirects

A2.60 LPN, like the other UKPN licensees is among the least efficient for CAI costs. It ranks 9th of the ten slow-track DNOs for CAI costs. Our modelled view is £16m or 4.9% lower than its submitted forecast. Costs are assessed as inefficient for the CAI regressed activities.

Business support and non-op capex

A2.61 LPN ranks 9th for BSCs but is still efficient according to our benchmarking. Our modelled costs are £13m or 8% higher than LPN's forecast costs.

A2.62 LPN is among the least efficient DNOs for non-op capex costs, ranking 9th of the ten slow-track DNOs. Our modelled costs are £11m or 18% lower than LPN's forecast costs. The high costs for IT&T and property outweigh the efficiencies in vehicles and transport.

SPN

Reinforcement

A2.63 SPN is in the middle of the pack on reinforcement, ranking 5th of the ten slow-track DNOs with our modelled costs 6m or 3% lower than its submitted forecasts.

A2.64 We apply a reduction to SPN's submitted volumes of LCT related network interventions and associated unit costs. We are applying no other volume adjustments.

A2.65 We make a small reduction to SPN's unit costs for n-1 primary network reinforcement and other work captured in the load index secondary deliverables, but we apply a qualitative adjustment to close 95% of the gap based on the strength of its scheme papers. Our modelled view also makes cuts to unit costs for secondary reinforcement (non-LCTs) and fault level reinforcement. We are making no adjustments its TCP charges.

Connections

A1.4 SPN ranks 5th of the ten slow-track DNOs for connections. Our modelled costs are £1m or 6% lower than SPN's forecast costs.

Asset replacement

A2.66 SPN benchmarks poorly on asset replacement (8th of the ten slow-track DNOs). Our modelling is £31m or 11% lower than SPN's forecast costs.

A2.67 Its asset replacement volumes are too high for a number of asset categories.

A2.68 We applied a reduction overall to our modelled view of LV switchgear volumes because we view that forecast volumes were far higher than their historic replacement rates with insufficient justification to support the difference.

A2.69 We applied a reduction to SPN's HV BLX conductor replacement volumes because our consultants believe the volumes forecast are not credible and significantly higher than in DPCR5. We scaled back reductions to our modelled view of SPN's HV switchgear volumes following a cross check with the asset health and criticality secondary deliverables.

A2.70 SPN has high asset replacement unit costs for a number of categories including underground LV services, HV cable, 132kV cable and switchgear.

Refurbishment

A2.71 SPN ranks 4th of the ten slow-track DNOs for refurbishment costs. Our modelled costs are £2m or 8% lower than forecast costs. SPN benchmarks well on pole refurbishment costs when compared with our view but this is outweighed by high transformer refurbishment costs.

Civil works

A2.72 SPN is among the most efficient DNOs for civil works costs, ranking 2nd of the ten slow-track DNOs Our modelled costs are £17m or 39% higher than SPN's forecast costs. We make positive adjustments to our modelled view of both the volumes and unit costs for civil works driven by condition at HV substations.

Non-core network investment

A2.73 SPN ranks 5th for non-core non-load-related expenditure. Our modelled view is £3m or 2% lower than SPN's forecast costs. This is driven by SPN's comparatively high costs in operational IT&T, ESQCR and BT21C.

Network operating costs (NOCs)

A2.74 SPN ranks 8th for NOCs. Our modelled costs are £20m or 5% lower than its forecast costs. Its comparatively high costs in inspections and maintenance, tree cutting and NOCs other account for this. Performance is better for ONIs costs.

Closely associated indirects

A2.75 SPN is the least efficient DNO for CAI costs. Our modelled view is £47m or 13% lower than its submitted forecasts. Costs are assessed as inefficient in all areas, with the most significant difference in the eight regressed areas of CAI costs.

Business support and non-op capex

A2.76 For BSCS our modelled costs are £14m or 8% higher than SPN forecast costs.

A2.77 SPN ranks 8th for non-op capex costs. Our modelled costs are £11m or 15% lower than SPN's forecast costs. Our modelled view of costs is lower than SPN's forecast for IT&T, property and vehicles and transport.

EPN

Reinforcement

A2.78 EPN is the frontier DNO for reinforcement costs with our modelled costs 51m or 18% higher than its submitted forecasts.

A2.79 We are making a reduction to EPN's submitted view of capacity added relative to maximum demand growth for n-1 primary network reinforcement and other work captured in the load index secondary deliverables, but have closed 82% of the gap based on the quality of its schemes papers. The reduction is more than offset by an increase to our modelled view of its unit costs that are below the industry median.

A2.80 We also apply an increase to the submitted view of EPN's volumes of LCT related network interventions. This increase is partially offset by a reduction to its submitted unit costs of network interventions which are above the industry median.

A2.81 Our modelled view of EPN's unit costs for other primary network reinforcement and costs for secondary reinforcement (non-LCTs) are higher than EPN's forecast costs which on average are low relative to the industry median. We are cutting its unit costs for fault level reinforcement.

A2.82 We make no adjustments to our modelled view of its TCP charges.

Connections

A2.83 EPN ranks 3rd for connections, with our modelled costs £1m or 2% lower than EPN's forecast costs.

Asset replacement

A2.84 EPN is the least efficient DNO on asset replacement. Our modelling is £84m or 19% lower than EPN's forecast costs.

A2.85 EPN benchmarks poorly on asset replacement volumes for a number of asset categories.

A2.86 We applied a reduction overall to our modelled view of LV switchgear volumes because the forecast volumes were far higher than their historic replacement rates with insufficient justification to support the difference.

A2.87 Our modelled view of HV conductor volumes is lower than EPN's forecast. We scaled back the reductions our modelling suggested following a review of EPN's supporting narrative. Despite this, our view is still significantly lower than EPN's forecast.

A2.88 We applied a large reduction to EPN's 132kV conductor volumes as its forecast was significantly above our modelled volumes and there was insufficient justification to support the difference. We scaled back our modelled view of reductions to EPN's HV switchgear and transformer volumes following a cross check with the asset health and criticality secondary deliverables.

A2.89 EPN has relatively high asset replacement unit costs for a number of categories including underground HV cables and switchgear, EHV conductor, cable and transformers and 132kV switchgear and cables.

Refurbishment

A2.90 EPN ranks 3rd of the ten slow-track DNOs for refurbishment costs. Our modelled costs are £2m or 7% lower than forecast costs. EPN benchmarks well on pole refurbishment costs when compared with our view, however this is outweighed by high transformer refurbishment costs.

Civil works

A2.91 EPN ranks 5th for civil costs, with our modelled costs £3m or 3% higher than EPN's forecast costs. Our modelled view shows a large positive adjustment for civil works driven by condition at HV substations.

Non-core network investment

A2.92 EPN ranks 8th of the ten slow-track DNOs for non-core non-load-related expenditure. Our modelled costs are £17m or 6% lower than EPN's forecast costs. This is driven largely by comparatively high costs in ESQCR, BT21C and diversions.

Network operating costs (NOCs)

A2.93 EPN is in the middle of DNOs for NOCs, ranking 5th. Our modelled costs are largely in line with EPN's forecast costs.

Closely associated indirects

A2.94 EPN ranks 7th for CAI costs. Our modelled costs are largely in line with EPN's forecasts.

Business support and non-op capex

A2.95 EPN ranks 7th for BSCs. Our modelled costs are £18m or 8% higher than EPN forecast costs.

A2.96 EPN ranks 4th of the ten slow-track DNOs for non-op capex costs. Our modelled costs are largely in line with EPN's forecast costs.

SPD

Reinforcement

A2.97 SPD benchmarks very well on reinforcement, ranking 2nd of the ten slow-track DNOs, with our modelled costs £13m or 10% higher than its submitted forecasts.

A2.98 We have also applied an increase to SPD's submitted volumes of LCT related network interventions and associated unit costs. We are applying no other adjustments to its volumes.

A2.99 Our modelled view of SPD's unit costs is lower than its forecast for n-1 primary network reinforcement and other work captured in the load index secondary deliverables, but we have closed 94% of the gap based on the quality of its schemes papers. We are also applying reductions to submitted unit costs for other primary reinforcement and fault level reinforcement. Our modelled costs are slightly higher than SPD's forecast costs for secondary reinforcement (non-LCTs).

A2.100 We make no adjustments to its TCP charges.

Connections

A2.101 SPD benchmarks 9th on connections with our modelled costs £1m or 27% lower than its forecasts.

Asset replacement

A2.102 SPD is at the frontier for asset replacement costs. Our modelled view is £5m or 2% lower than its forecast cost.

A2.103 Despite the overall strong performance, SPD benchmarks poorly on asset replacement volumes for a number of asset categories.

A2.104 We applied a reduction to our modelled view of SPD's HV conductor volumes because the forecast volumes are far higher than their historic replacement rates with insufficient justification to support the difference. We have also applied a significant reduction to our modelled view of SPD's HV cable volumes for similar reasons.

A2.105 We applied a large reduction to our modelled view of SPD's EHV cable volumes as our consultants could not disaggregate between replacement volumes for 11kV and 33kV cables and SPD does not justify the increased 2014 volumes, which were high. Our consultants recommended significant reductions be made to our view of SPD's 33kV conductor replacement volumes due to there being almost no spend historically.

A2.106 We scaled back the differences between our modelled view and SPD's forecasts for HV pole and switchgear volumes following a cross check with the asset health and criticality secondary deliverables.

A2.107 SPD generally has low asset replacement unit costs, however our modelled view is significantly lower than its forecast for LV conductor and switchgear and EHV switchgear.

Refurbishment

A2.108 SPD ranks 7th of the ten slow-track DNOs for refurbishment costs. Our modelled view is £6m or 12% lower than its forecast costs. Our modelled view of both 6.6/11kV and 33kV pole refurbishment volumes is significantly lower than SPD's forecast, but this is mitigated in part by a positive unit cost adjustment due to its low pole refurbishment costs. SPD benchmark well against our 33kV protection refurbishment cost.

Civil works

A2.109 SPD benchmarks 6th on civil works with our modelled costs £1m or 2% lower than its forecasts. For EHV building and HV outdoor substations volumes our modelled view is lower than the SPD's submitted.

Non-core network investment

A2.110 Our modelled view of SPD's non-core costs is £3m or 3% higher than SPD's forecast in our disaggregated benchmarking. This is largely driven by efficiency in ESQCR costs.

Network operating costs (NOCs)

A2.111 Our modelled costs are £18m or 6% higher SPD's forecast costs. Our modelled costs being lower for tree cutting, but this is offset by its relative efficiency in troublecall, ONIs and inspection and maintenance.

Closely associated indirects

A2.112 SPD ranks 2nd of the ten slow-track DNOs on CAI costs. Our modelled costs are £31m or 11% higher than SPD's forecast costs. Our modelled view of costs for operational training are higher than SPD's forecast. Additionally, its relatively strong performance for the eight regressed areas of CAI costs, wayleaves and vehicles and transport result in our modelled costs being higher than forecast costs.

Business support and non-op capex

A2.113 SPD ranks 5th for BSCs. Our modelled costs are £16m or 10% higher than SPD's forecast costs.

A2.114 SPD also ranks 5th for non-op capex costs. Our modelled costs are £3m or 5% lower than SPD's forecast costs. It's relatively low costs for IT&T do not fully compensate for high costs for property and vehicles and transport.

SPMW

Reinforcement

A2.115 SPMW ranks 3rd on reinforcement with our modelled costs £14m or 9% higher than its submitted forecasts.

A2.116 Our modelled view results in a small reduction to SPD's capacity added relative to maximum demand growth for n-1 primary network reinforcement and other work captured in the load index secondary deliverables, but we have closed 94% of the gap based on the quality of SP's schemes papers. We are also applying a small reduction to its submitted unit costs for this work.

A2.117 Our modelling applies a small reduction to SPMW's submitted volumes of LCT related network interventions. This is based on benchmarking its forecast of network interventions per MW of LCTs connected to the industry median. We are applying no other adjustments to its volumes.

A2.118 We are applying a large reduction to SPMW's submitted costs of other primary network reinforcement based on its high unit costs and are applying an increase for secondary network reinforcement (non-LCTs). We have accepted SPMW volumes and unit costs for fault reinforcement in the round as they have high volumes and low unit costs compared to the majority of other DNOs. We are making a small qualitative volume adjustment for primary reinforcement due to SPMW special case.

A2.119 We are making no adjustments to its TCP charges.

Connections

A2.120 SPMW ranks 4th of the ten slow-track DNOs on connections, with our modelled costs £1m or 5% lower than its forecasts.

Asset replacement

A2.121 SPMW ranks 5th of the ten slow-track DNOs on asset replacement. Our modelled costs are £29m or 7% lower than its forecast costs, largely due to submitted unit costs being assessed as high.

A2.122 SPMW benchmarks relatively well on asset replacement volumes for the majority of asset categories.

A2.123 Our modelled view of batteries at ground mounted HV substations was significantly lower than SPMW's forecast. We applied a reduction to our modelled view of SPMW's to EHV switchgear volumes because it was unclear why addition volumes were higher than disposals.

A2.124 We have scaled back the reductions our model makes to SPMW's forecast EHV pole, switchgear and 132kV switchgear volumes following a cross check with the asset health and criticality secondary deliverables.

A2.125 SPMW has relatively high asset replacement unit costs. Some of the categories that we consider to have high unit costs are underground LV conductor and switchgear, 132kV conductor, poles, towers, transformers and switchgear.

Refurbishment

A2.126 SPMW ranks 10th of the ten slow track DNOs for refurbishment. Our modelled view of refurbishment costs is £42m or 45% lower than SPMW's forecast. It benchmarks poorly due to high 33kV and 132kV volumes and costs. Our modelled view is also significantly lower than SPMW's forecast due to high HV switchgear and transformer refurbishment costs. Our modelled view applies a significant volume reduction to both 6.6/11kV and 33kV pole refurbishment, however SPMW does benchmark well in these areas in terms of low refurbishment costs.

Civil works

A2.127 SPMW ranks 9th of the ten slow-track DNOs on civil works with our modelled costs £21m or 28% lower than its forecasts. For SPMW some of our modelled costs for civil works at 33kV and 66kV substations and HV indoor substations were lower than SPMW's forecasts due to its high unit costs, and our modelled volumes for plinths and groundworks at 132kV were also lower.

Non-core network investment

A2.128 SPMW ranks 4th of the DNO for non-core costs. Our modelled costs are 1% (£4m) lower than its forecast costs. Our modelling suggests inefficiency in BT21C but this is largely offset by efficiencies in legal and safety and ESQCR costs.

Network operating costs (NOCs)

A2.129 SPMW ranks 2nd on NOCs. Our modelled costs are £15m or 4% higher than forecast costs. This reflects efficient costs for troublecall, ONIs and tree cutting.

Closely associated indirects

A2.130 SPMW ranks in the middle of the pack on CAI costs. Our modelled costs are £7m or 2% higher than SPMW forecast.

Business support and non-op capex

A2.131 SPMW ranks 6th for BSCs. Our modelled costs are higher than SPMW's forecast costs for BSCs (£13m or 10%).

A2.132 SPMW ranks 7th of the ten slow-track DNOs for non-op capex costs. Our modelled costs are £7m or 14% lower than SPMW's forecast costs because of high IT&T and property costs.

SSEH

Reinforcement

A2.133 SSEH ranks 6th on reinforcement with our modelled costs £2m or 3% lower than its submitted forecasts.

A2.134 Our modelled view shows an increase to SSEH's forecast volumes of LCT related network interventions. This is partially offset by our modelled unit costs being lower than SSEH's forecasts. We are applying no other adjustments to its volumes.

A2.135 Our modelled view of SSEH’s unit costs for n-1 primary network reinforcement and other work captured in the load index secondary deliverables is lower than its forecast. We have not closed any of the gaps for our quantitative assessment based on the scheme papers submitted. Our modelled unit costs for other primary network reinforcement are also lower than SSEH’s forecast.

A2.136 Our modelled view shows an increase to SSEH’s forecast cost due to low unit costs for secondary reinforcement relative to the industry.

A2.137 We are making no adjustments to its TCP charges.

Connections

A2.138 SSEH is the least efficient DNO on connections. Our modelled costs are £9m or 29% lower than SSEH’s forecast costs.

Asset replacement

A2.139 SSEH ranks 7th on asset replacement. Our modelled view is £19m or 9% lower than its forecast costs.

A2.140 SSEH benchmarks well on asset replacement volumes for the majority of asset categories.

A2.141 We scaled back the reductions to SSEH’s submitted volumes in our modelled view of HV and EHV submarine cables due to input from our consultants as these cables are installed in rocky environments with strong tides and have undergone recent condition assessments. However, SSEH provided insufficient evidence for its assumed average life of 24 years, therefore was unable to bridge the gap completely.

A2.142 We scaled back our modelled view’s reductions to SSEH’s EHV switchgear volumes following a cross check with the asset health and criticality secondary deliverables.

A2.143 SSEH has relatively low asset replacement unit costs however our modelled view was significantly lower than its forecast for LV conductor, HV poles, submarine cables and switchgear.

Refurbishment

A2.144 SSEH is the frontier of the ten slow-track DNOs in refurbishment. Our modelled costs are £3m or 12% higher than its submitted costs. It benchmarks well on LV and HV pole refurbishment costs, however our modelled costs are lower due to its high HV switchgear volumes.

Civil works

A2.145 SSEH is the frontier DNO on civil works with our modelled costs £8m or 53% higher than its forecasts. For SSEH the efficiency is explained by both volume and unit costs. Positive volume adjustments to our modelled view were made for civil works at EHV substations and positive unit cost adjustment for civil works at HV indoor substations.

Non-core network investment

A2.146 SSEH is the least efficient DNO for non-core costs. Our modelled costs are £10m or 18% lower than SSEH's forecast costs. This is largely driven by its comparatively high unit costs for losses and other environmental costs. Our view of the improved resilience costs (for WSCs) is lower than SSEH's submitted costs. SSEH is the only DNO that submitted costs for this.

Network operating costs (NOCs)

A2.147 For NOCs, our modelled view is slightly higher than SSEH's forecast costs (£15m or 6%). Relatively inefficient costs in NOCs other are largely offset by efficient costs in tree cutting and inspections and maintenance.

Closely associated indirects

A2.148 SSEH ranks 8th of the ten slow-track DNOs on CAI costs. Our modelled view is £2m or 1% lower than its submitted forecasts. Our modelled view's lower costs for vehicles and transport and operational training are almost offset by the stronger performance in way-leaves.

Business support and non-op capex

A2.149 Our modelled costs are higher than SSEH's forecast costs for BSCs (£22m or 15%). SSEH ranks 4th for BSCs.

A2.150 SSEH is the least efficient among ten slow-track DNOs for non-op capex. Our modelled view is £11m or 24% lower than SSEH's forecast costs, due to high vehicles and transport, and property costs.

SSES

Reinforcement

A2.151 SSES performs poorly on reinforcement. It ranks 9th of the ten slow-track DNOs, with our modelled costs £32m or 14% lower than its submitted forecasts.

A2.152 Our modelled view shows a reduction to SSES's capacity added relative to maximum demand growth for n-1 primary network reinforcement and other work captured in the load index secondary deliverables. Our modelled view of its associated unit costs is also lower. We have closed 30% of the gap based on a review of its scheme papers.

A2.153 Our modelled view shows an increase to SSES's forecast volumes of LCT related network interventions and associated unit costs. We are applying no other adjustments to its volumes.

A2.154 Our modelled view of SSES's unit costs for other primary network reinforcement and secondary reinforcement (non-LCTs) is lower than its forecast. We are applying a positive adjustment for fault level reinforcement.

A2.155 We are making no adjustments to its TCP charges.

Connections

A2.156SSES ranks 8th on connections, with our modelled view £4m or 21% lower than its forecast costs.

Asset replacement

A2.157 SSES is one of the best of the ten slow track DNOs, ranking 2nd on asset replacement. Our modelled view of costs is £14m or 3% lower than its forecast costs.

A2.158 SSES benchmarks well on asset replacement volumes for most asset categories.

A2.159 Our modelled view of SSES's HV cable volumes is significantly lower than its forecast, however this gap was reduced as plans to underground large amounts of overhead line were found to be justified by our consultants.

A2.160 We scaled back our modelled reductions to SSES's EHV switchgear and 132kV switchgear volumes following a cross check with the asset health and criticality secondary deliverables.

A2.161 SSES has low asset replacement unit costs overall. But our modelled view of its LV conductor, cables, EHV cables and 132kV conductor asset categories was significantly lower than its forecasts.

Refurbishment

A2.162SSES ranks 5th on asset replacement. Our modelled view is £9m or 9% lower than its forecast costs. It benchmarks well on tower foundation refurbishment costs, but other tower refurbishment costs are very high. Our modelled view was significantly lower for 33kV transformer refurbishment volumes, but this is offset due to its low cost in this asset category.

Civil works

A2.163 SSES benchmarks well on civil works with our modelled costs £9m or 25% higher than its forecasts. It ranks 3rd of the ten slow-track DNOs. Our modelled view is notably higher for civil works at HV indoor substations.

Non-core network investment

A2.164 SSES is among the most efficient DNOs for non-core costs. Our modelled costs are higher than SSES's forecast costs (£2m or 4%). Our modelled view's lower legal and safety costs are more than offset by higher modelled costs for operational IT&T and diversions.

Network operating costs (NOCs)

A2.165 Our modelled view is £14m or 3% higher than the NOCs forecast costs for SSES. Its efficient costs for troublecall and ONIs are offset by inefficient costs for tree cutting, and inspection and maintenance.

Closely associated indirects

A2.166 SSES ranks 6th of the ten slow-track DNOs on CAI costs. Our modelled view is £7m or 2% higher than its submitted forecasts. Our lower modelled view of costs for vehicles and transport are fully offset by the strong performance in the CAI regressed areas and operational training.

Business support and non-op capex

A2.167 SSES is among the most efficient DNOs on BSCs. Our modelled costs are higher than SSES's forecast costs for BSCs (£34m or 16%). SSES ranks 3rd for BSCs.

A2.168 SSES ranks 6th for non-op capex costs, with our modelled view £9m or 11% lower than its forecast costs. Our modelled costs are lower for property and vehicles and transport. This is offset a little by its performance in IT&T costs.

Appendix 3 - Approach to econometric benchmarking

Draft determinations approach

A3.2 Given the nature of the data, our approach to benchmarking relies on both econometric modelling and well justified pre and post estimation adjustments as discussed in Chapter 4. We treat the error terms or residuals from the econometric models as inefficiency based on using regulatory knowledge and judgement to capture other factors that influence costs. We make appropriate adjustments to normalise company data prior to the benchmarking, reverse our normalisations after the regression and benchmark at the UQ.

A3.3 The approach adopted for estimating efficient costs for the slow-track draft determinations assessment followed a number of steps. These are summarised below.

Normalisations and other adjustments

A3.4 Where costs were available on a comparable basis across companies we used regression based benchmarking to estimate efficient costs. For costs that were not comparable we applied adjustments to the companies' actual and forecast expenditure using separate analysis in order to determine an efficient view. These cost components included regional labour costs, company specific factors and costs that were excluded due to being incurred by a small number of DNOs or outside of the DNOs' control.

Estimation of cost models

A3.5 The main estimation technique that we adopted for our slow-track draft determinations assessment was Pooled Ordinary Least Squares (pooled OLS) (with cluster robust standard errors) using a log-log (Cobb Douglas) cost function. This was adopted for both our totex regressions using high level and disaggregated activity level drivers, and for our three disaggregated regressions. These regressions covered tree cutting expenditure, low and high voltage overhead troublecall, and the majority of CAI costs.

A3.6 Ordinary least squares (OLS) estimates the line of best fit (the cost function) through the data points. We pooled the data across various time periods (DPCR5 actuals 2010-11 to 2013-14, RIIO-ED1 forecasts 2015-16 to 2022-23, or the full thirteen years 2010-11 to 2022-23) for the 14 DNOs into a single data set for the regressions. We estimated a single set of slope parameters for all years using this data.

A3.7 We used these parameters to forecast modelled costs for RIIO-ED1. These models were based upon company forecasts of the cost drivers, which were subject to close scrutiny and modification if required. We tested a number of sensitivities to our analysis. We estimated the parameters in the cost functions using 13 years of data rather than data for just the historical years in draft determinations. We also considered the impact of using Random Effects (RE) rather than our pooled OLS methodology. RE produced very similar results to pooled OLS (covered in Appendix 6).

A3.8 We applied our view of RPEs to estimate modelled costs including RPEs.

Calculation of efficiency scores and the UQ

A3.9 We calculated the efficiency scores for each DNO as the ratio of total forecast normalised net costs for RIIO-ED1 relative to total modelled costs (both including RPEs and on a net basis). We calculated the UQ level of efficiency (lowest 25th percentile of costs) across the 14 DNOs based on these efficiency scores.

Reversal of adjustments

A3.10 We reversed the regional factors and added back our view of efficient company specific factors and costs excluded from the regressions.

Modelled costs

A3.11 The final step was to apply the UQ to our estimated costs (post reversal of adjustments) to determine efficient costs. This is effectively equivalent to shifting the regression line so that it passes through the UQ level of efficiency (lower quartile in the distribution of efficiency scores).

Responses

A3.12 Responses on our econometric modelling following our slow-track draft determinations raised issues on:

- our weighting of models in the toolkit
- using MEAV as a driver in both models
- the number of exclusions to totex (some suggested adding to the exclusions, others suggested reducing the number)
- time periods being regressed
- our use of regressions.

A3.13 Responses to these issues are covered in detail Chapter 4 and 5. More general points are outlined below.

Revised slow-track assessment

A3.14 Our slow-track assessment incorporates the following sequential steps:

1. Choice of Data for Benchmarking
2. Choice of Costs for Benchmarking
3. Choice of Estimator

4. Model Selection
5. Weighting of totex and activity level assessments
6. Setting the efficiency benchmark.

Choice of data for benchmarking

A3.15 A relatively small sample size was used in our analysis for RIIO-ED1 (both in terms of the number of DNOs and number of years) and inspection of the data reveals relatively limited time series variation. Our choice of time period is based upon the quality of the underlying data and the appropriateness of the models based on the statistical criteria discussed in Appendix 4. We consider that making greater use of forecast data where possible better takes into account the scope for efficiency savings in RIIO-ED1.

A3.16 At slow-track draft determinations we considered alternative time periods for estimating the parameters in our regression models. This included the historical years of DPCR5 (2010-11 to 2013-14), forecast data for RIIO-ED1 (2015-16 to 2022-23) and the full thirteen year period (2010-11 to 2022-23). We used different diagnostic tests to determine the validity of utilising time windows of different length. For example, for CAI we estimated regressions on the full 13-year period, but they performed poorly against our statistical tests.

A3.17 Following the outcomes of these tests, for draft and final determinations the estimation of the parameters are based on:

- the full 13-year period in the two totex models
- four years historical data in the troublecall model
- eight-year RIIO-ED1 forecasts for the tree cutting and CAI models.

Choice of estimator

A3.18 We used pooled OLS with cluster robust standard errors as the main estimation technique in our cost modelling for draft and final determinations.

A3.19 For draft and final determinations we carried out sensitivity analysis using both the pooled OLS and RE estimators for our regression models. Our findings show that there is very little difference in parameter estimates, modelled costs and efficiency scores between the two estimators. Further details are set out in Appendix 6.

A3.20 We do not consider that the use of RE provides much benefit given the additional complexity involved, and the very similar results we estimated. Kennedy (1998)[52] argues that in panel data with a small number of companies the RE estimator should typically

[52] Peter Kennedy, A Guide to Econometrics. 4th ed. Cambridge: MIT Press, 1998.

not be used. A large number of companies are required to estimate a time invariant DNO effect such as inefficiency.

Model Selection Process

A3.21 In response to concerns raised by the DNOs regarding the justification of our models used at fast-track, for draft determinations we developed a revised model selection process. We make no changes for final determinations. The steps are detailed below.

Selection of cost drivers

A3.22 For both totex and our activity-based analysis we identified a set of appropriate cost drivers that are relevant to the costs being considered from an economic or an engineering perspective. We also considered whether the drivers are within or outside of the DNOs' control. Further we investigated various combinations of these possible drivers throughout the process.

- For our top-down totex model we considered the following set of drivers: customer numbers, units distributed, network length, MEAV, peak and density.
- For the bottom-up totex model specification we chose drivers that were related to the cost areas being assessed (eg units distributed for reinforcement).
- For the disaggregated regressions we wanted to keep the drivers as closely aligned to the activity volumes for each area (ie tree cutting based on spans cut and inspected, LV and HV overhead fault costs driven by associated faults). CAI was subject to more investigation prior to slow-track draft determinations.

Selection of Regression Models

A3.23 The number of data points and issues with multi-collinearity imposed a constraint on the manner in which we chose models for totex and each activity. In particular it was not practical to follow a general to specific approach to model specification and testing. Under that approach we would start with a general model including all of the cost drivers and adopt a testing strategy which determines a final regression model for each activity area. Instead we estimated regression models in parallel with a single driver and multivariate regressions based upon combinations of cost drivers that made sense from either an economic or engineering perspective using up to three cost drivers. We have assessed the appropriateness of the models using the following factors, whether:

- the driver(s) can be justified on either economic and/or engineering grounds
- the coefficients of the variables have plausible signs and magnitudes
- the regression met our statistical tests including the pooling test, Ramsey Regression Specification Error Test (RESET test) and tests for normality and heteroskedasticity.

A3.24 The key statistical tests are the RESET and the pooling test. Our regression approach uses cluster robust standard errors. This approach accounts for the natural clustering of time series observations for each company and is also robust to heteroskedasticity. As such we have included some regressions in our final modelling which fail on normality and heteroskedasticity but are otherwise robust.

A3.25 The final determination models for totex and our activity-based analysis have been selected on the basis that they best meet these criteria. Where no regressions have met these criteria or where the results from the modelling were not plausible, we have utilised alternative approaches such as ratio benchmarking or qualitative analysis.

Sensitivities

A3.26 We have run sensitivities using the RE estimator as an alternative to POLS. These are described in Appendix 6. At draft determinations we ran a range of alternative models with different cost drivers and periods for the estimation of parameters for CAI and totex in particular. For slow-track final determinations we have not altered the choice of drivers chosen for our regressions. We extensively reviewed possible alternate drivers prior to draft determinations and their plausibility. For final determinations we remain with the drivers that we chose at draft determinations, MEAV and customer numbers, as we are satisfied that the drivers remain the most sensible option. At a high level they take account of the scale and composition of a network, and the activities that customers require of a DNO including operating, maintaining and reinforcing the network.

Weighting of totex and activity level assessment

A3.27 We have given further consideration to the relative weighting of the totex analysis and disaggregated assessment taking account of the DNOs' responses. The different modelling approaches all provide useful information in assessing the appropriateness of DNOs' forecasts for RIIO-ED1 and setting efficient expenditure baselines.

A3.28 Totex models take into account trade-offs between activities, differences in business models and reporting. They identify those DNOs that have minimised total costs. In contrast, activity level analysis enables us to separate total expenditure according to the constituent activities, and as a result, utilise regression models where it is easier to match variation in the specific costs and the cost drivers. In total we can take account of a greater number of factors that influence costs across the different elements of our cost modelling.

A3.29 At slow-track the DNOs made significant improvements to the quality of their business plan data and we have scrutinised this data in detail. We therefore have more confidence in the data underlying the totex regressions and consider it is appropriate to place greater weight on the totex regressions. We have concluded that it is appropriate to give a 25% weighting to each of our totex models as both specifications of totex provide useful information in terms of the efficiency of the DNOs and a 50% weighting to our disaggregated assessment in our slow-track assessment. Our totex regressions models have better statistical results than the disaggregated regression models in our slow-track assessment.

Setting the efficiency benchmark

A3.30 We combine the results of all three models before calculating the UQ level of efficiency. This takes into account interactions between our activity level analysis and ensures that we avoid setting an artificially efficient benchmark that no company can achieve. Prior to applying the UQ adjustment we first reintroduced costs that were excluded from the regression benchmarking. The application of the UQ benchmark after combining the models avoids the risk of applying an UQ separately for each model and setting an unrealistic cost benchmark.

A3.31 We then apply our assumptions for RPEs and smart grid savings to the UQ cost benchmarks.

A3.32 Under the IQI our final cost allowances are based upon 75% of the Ofgem benchmark and 25% of the DNO forecast. As such we are assuming that the DNOs would close 75% of the assessed gap between their forecasts and our efficiency benchmark. Our proposed approach to closing the gap and the use of the UQ rather than the frontier acknowledges that a part of the difference in costs across the DNOs relates to factors other than DNOs' relative efficiency (eg statistical errors).

Appendix 4 – Statistical tests and regression results

Statistical tests

A4.1 We used a number of statistical tests in consultation with our academic advisor for the panel data models. These tests provide an indication of the robustness of the modelling results and also indicate where parameter estimates might be biased and require an adjustment to the model specification.

A4.2 We use the results from statistical diagnostic tests to inform our judgement in identifying the best models. The tests are:

- RESET test for model misspecification
- White test for heteroskedasticity
- Skewness and Kurtosis test for normality
- F-test for parameter stability.

A4.3 We investigated the outcome of the statistical tests and made appropriate adjustments to the specified model. For example when the RESET test failed we reviewed the functional form of the model and tested different drivers.

A4.4 Some of these tests are more critical than others, particularly the RESET test, because it is directly relevant in assessing the validity of a given model specification.

The Ramsey RESET test

A4.5 The RESET is a general test for model misspecification. As an example, conditional on the selected cost drivers, tests can be used to identify incorrect functional form – some or all of the variables (ie the costs and the driver) may need to be transformed to logs or higher order powers.

White test for heteroskedasticity

A4.6 When an OLS regression is run it produces estimates of the standard errors for each of the coefficients in the model. These standard errors are a measure of the uncertainty surrounding the parameter estimates and can be used to perform hypothesis tests on the model's coefficients.

A4.7 Heteroskedasticity can cause the standard errors and inference using hypothesis tests to be biased. It can occur when the variation in the residuals change over time. For example, if the residuals were very large in magnitude in some periods compared to others then this would be an indication of heteroskedasticity.

A4.8 Heteroskedasticity may also be driven by the error variance differing as a result of the model not fully capturing scale differences for the cross-section of comparators.

A4.9 Although robust standard errors can account for the impact of heteroskedasticity of unknown form, we test for heteroskedasticity using the White test since any violation might be an indicator of a more general model misspecification. One possible example of this would be the occurrence of heteroskedasticity due to greater uncertainty around the regression line during the forecast period, relative to the historical data.

Panel robust standard errors

A4.10 We have estimated our models using clustered robust standard errors to allow for the fact that the set of observations in the panel are not independent but clustered by DNO. These standard errors are also robust to heteroskedasticity.

Skewness and Kurtosis test for normality

A4.11 The Skewness and Kurtosis (SKtest) test is used to test whether the residuals are normally distributed. Although normality of residuals is not necessary to obtain parameter estimates with good properties, it is an indication of a well behaved model. The SKtest returns a combined test statistic for normality based on skewness and another based on kurtosis.

F-test for parameter stability

A4.12 We use an F-test to determine whether the slope coefficients are stable over time. If any differences are not found to be statistically significant, then the data can be pooled over the given years. If they are statistically different then there is no justification for pooling the data.

Variable definitions

A4.13 Table A4.1 explains the terms used in our regressions, and presented further in this appendix.

Table A4.1: Explanation of terms

Data term	Explanation of the term
ln_totex_excl	The natural log of total expenditure excluding certain costs.
ln_bu_csv	The natural log of the disaggregated activity level analysis drivers (comprised of units distributed, total network length, LV and HV overhead line length, MEAV*, customer numbers, spans cut, total faults, and total ONIs).
MACRO_CSV	The high level drivers (natural log of customer numbers, and natural log of MEAV*)
ln_tree_cutting	The natural log of tree cutting expenditure.
ln_spans_cut	The natural log of spans cut.
ln_spans_inspected	The natural log of spans inspected.
ln_tc_lv_hv_ohl	The natural log of LV and HV overhead line expenditure.
ln_faults_lv_hv_ohl_ex_sw	The natural log of LV and HV overhead line faults excluding switching related faults.
ln_CAI2	The natural log of closely associated indirect expenditure for the following cost areas: network design; project management; system mapping; engineering management and clerical support; stores; network policy; control centre; and call centre.
ln_MEAV_SPMWSF_WLA	The natural log of MEAV*.
ln_V1_additions	The natural log of new assets installed.
year	A time trend.

*MEAV excludes the following assets in its calculation: rising and lateral mains (RLM), LV service associated with RLM, batteries at ground mounted HV substations, batteries at 33kV substations, batteries at 66kV substations, batteries at 132kV substations, pilot wire overhead, pilot wire underground, cable tunnels (DNO owned), cable bridges (DNO owned), and electrical energy storage.

Regression equations and results

A4.14 The following tables present the equations and the results from our econometric modelling.

Table A4.2: Regression equations

Cost Area	Regression Number	Regression Equation
Totex	1	$\ln(totex\_excl) = \alpha + \beta1*\ln(bu\_csv) + \beta2*year$
	2	$\ln(totex\_excl) = \alpha + \beta1*MACRO\_CSV + \beta2*year$
Tree Cutting	3	$\ln(tree\_cutting) = \alpha + \beta1*\ln(spans\_cut) + \beta2*\ln(spans\_inspected)$
Troublecall	4	$\ln(tc\_lv\_hv\_ohl) = \alpha + \beta1*\ln(faults\_lv\_hv\_ohl\_ex\_sw)$
Closely Associated Indirects	5	$\ln(CAI2) = \alpha + \beta1*\ln(MEAV\_SPMWSF\_WLA) + \beta2*\ln(V1\_additions)$

Regression 1 – Totex bottom-up CSV

```
Linear regression                                      Number of obs =      182
                                                       F(  2,     13) =   135.47
                                                       Prob > F      =   0.0000
                                                       R-squared     =   0.8799
                                                       Root MSE      =   .09542

                                        (Std. Err. adjusted for 14 clusters in dno)
```

ln_totex_e~l	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
ln_bu_csv	.8270017	.0525073	15.75	0.000	.7135666	.9404369
year	-.0127349	.0019422	-6.56	0.000	-.0169308	-.0085391
_cons	26.64619	3.898006	6.84	0.000	18.22506	35.06732

Statistical Test	p-value
Normality	0.30
Reset	0.55
White	0.01
Pooling	0.68
Observations	182
Adjusted R-squared	88%

Regression 2 – Totex Macro CSV

```
Linear regression                                      Number of obs =     182
                                                       F(  2,    13) =  112.71
                                                       Prob > F      =  0.0000
                                                       R-squared     =  0.8692
                                                       Root MSE      =  .09957

                                     (Std. Err. adjusted for 14 clusters in dno)
------------------------------------------------------------------------------
             |               Robust
ln_totex_e~l |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
   MACRO_CSV |   .7884815   .0536528    14.70   0.000     .6725717    .9043912
        year |  -.0144016   .0019428    -7.41   0.000    -.0185987   -.0102044
       _cons |   22.00889   3.746851     5.87   0.000     13.91431    30.10347
------------------------------------------------------------------------------
```

Statistical Test	p-value
Normality	0.20
Reset	0.51
White	0.04
Pooling	0.64
Observations	182
Adjusted R-squared	87%

Regression 3 – Tree cutting

```
Linear regression                                      Number of obs =     104
                                                       F(  2,    12) =   44.25
                                                       Prob > F      =  0.0000
                                                       R-squared     =  0.8546
                                                       Root MSE      =  .17569

                                        (Std. Err. adjusted for 13 clusters in dno)
-----------------------------------------------------------------------------------
                  |               Robust
  ln_tree_cutting |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
------------------+----------------------------------------------------------------
     ln_spans_cut |   .6802667   .1690803     4.02   0.002     .3118723    1.048661
ln_spans_inspected |   .4566663   .1968299     2.32   0.039     .0278107    .8855218
            _cons |  -10.13218   1.408445    -7.19   0.000    -13.20092   -7.063446
-----------------------------------------------------------------------------------
```

Statistical Test	p-value
Normality	0.01
Reset	0.15
White	0.00
Pooling	1.00
Observations	104
Adjusted R-squared	85%

Regression 4 – Troublecall LV & HV overhead faults

```
Linear regression                                      Number of obs =      52
                                                       F(  1,    12) =   52.52
                                                       Prob > F      =  0.0000
                                                       R-squared     =  0.4077
                                                       Root MSE      =  .31198

                                        (Std. Err. adjusted for 13 clusters in dno)
------------------------------------------------------------------------------
                          |               Robust
           ln_tc_lv_hv_ohl |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
--------------------------+---------------------------------------------------
ln_faults_lv_hv_ohl_ex_sw |   .7163438   .0988422     7.25   0.000     .5009851    .9317025
                    _cons |  -4.397999   .7761198    -5.67   0.000    -6.089018   -2.706979
------------------------------------------------------------------------------
```

Statistical Test	p-value
Normality	0.09
Reset	0.39
White	0.32
Pooling	0.59
Observations	52
Adjusted R-squared	40%

Regression 5 - CAI

```
Linear regression                                      Number of obs =     112
                                                       F(  2,    13) =   91.92
                                                       Prob > F      =  0.0000
                                                       R-squared     =  0.8682
                                                       Root MSE      =  .09899

                                        (Std. Err. adjusted for 14 clusters in dno)
------------------------------------------------------------------------------
                |               Robust
         ln_CAI2 |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
----------------+-------------------------------------------------------------
ln_MEAV_SPMWSF_WLA |   .5337895    .106859     5.00   0.000     .3029347    .7646443
  ln_V1_additions |    .331697   .1251493     2.65   0.020     .0613285    .6020656
            _cons |  -6.526078   1.251045    -5.22   0.000    -9.228796    -3.82336
------------------------------------------------------------------------------
```

Statistical Test	p-value
Normality	0.00
Reset	0.57
White	0.14
Pooling	0.25
Observations	112
Adjusted R-squared	87%

Summary Statistics

A4.15 The following tables show the decomposition of the between and within variance of the panel data that was used for each of the five regressions.

Table A4.3: Regression 1 – Totex bottom-up driver

var	category	mean	sd	min	max	obs
ln_totex_excl	overall	5.421083	.2737644	4.862175	6.077424	182
ln_totex_excl	between	.	.2709523	4.913241	5.912175	14
ln_totex_excl	within	.	.0799945	5.232711	5.648417	13
ln_totex_excl	B/W Variation	.	3.387136	.	.	.
ln_bu_csv	overall	5.39452	.3070048	4.836955	5.965346	182
ln_bu_csv	between	.	.3174528	4.858467	5.939809	14
ln_bu_csv	within	.	.0125292	5.351449	5.421971	13
ln_bu_csv	B/W Variation	.	25.33703	.	.	.
year	overall	2017	3.751979	2011	2023	182
year	between	.	0	2017	2017	14
year	within	.	3.751979	2011	2023	13
year	B/W Variation	.	0	.	.	.

Table A4.4: Regression 2 – Totex Macro driver

var	category	mean	sd	min	max	obs
ln_totex_excl	overall	5.421083	.2737644	4.862175	6.077424	182
ln_totex_excl	between	.	.2709523	4.913241	5.912175	14
ln_totex_excl	within	.	.0799945	5.232711	5.648417	13
ln_totex_excl	B/W Variation	.	3.387136	.	.	.
MACRO_CSV	overall	15.80273	.3203599	15.18225	16.38162	182
MACRO_CSV	between	.	.3309334	15.22676	16.34195	14
MACRO_CSV	within	.	.0193475	15.75821	15.84339	13
MACRO_CSV	B/W Variation	.	17.10473	.	.	.
year	overall	2017	3.751979	2011	2023	182
year	between	.	0	2017	2017	14
year	within	.	3.751979	2011	2023	13
year	B/W Variation	.	0	.	.	.

Table A4.5: Regression 3 – Tree cutting

var	category	mean	sd	min	max	obs
ln_tree_cutting	overall	1.391994	1.619327	-4.202262	2.806742	112
ln_tree_cutting	between	.	1.67245	-4.202262	2.683802	14
ln_tree_cutting	within	.	.039033	1.277829	1.555444	8
ln_tree_cutting	B/W Variation	.	42.84712	.	.	.
ln_spans_cut	overall	9.556617	1.909742	2.890455	10.90719	112
ln_spans_cut	between	.	1.972763	2.890455	10.90719	14
ln_spans_cut	within	.	.0273901	9.440866	9.653438	8
ln_spans_cut	B/W Variation	.	72.02473	.	.	.
ln_spans_inspected	overall	10.68508	1.816443	4.27675	11.94592	112
ln_spans_inspected	between	.	1.875907	4.27675	11.94592	14
ln_spans_inspected	within	.	.0485728	10.47277	10.84759	8
ln_spans_inspected	B/W Variation	.	38.62053	.	.	.

Table A4.6: Regression 4 – Troublecall LV & HV overhead faults

var	category	mean	sd	min	max	obs
ln_tc_lv_hv_ohl	overall	.9434534	1.131073	-4.819303	2.181463	54
ln_tc_lv_hv_ohl	between	.	1.511323	-4.396833	1.659731	14
ln_tc_lv_hv_ohl	within	.	.2758051	.302992	1.546018	3.857143
ln_tc_lv_hv_ohl	B/W Variation	.	5.479676	.	.	.
ln_faults_lv_hv_ohl_ex_sw	overall	7.617905	.9790721	1.098612	8.445912	53
ln_faults_lv_hv_ohl_ex_sw	between	.	1.806696	1.098612	8.317065	14
ln_faults_lv_hv_ohl_ex_sw	within	.	.1227465	7.373856	7.984653	3.785714
ln_faults_lv_hv_ohl_ex_sw	B/W Variation	.	14.71892	.	.	.

Table A4.7: Regression 5 – CAI

var	category	mean	sd	min	max	obs
ln_CAI2	overall	3.554551	.2701855	3.031501	4.177659	112
ln_CAI2	between	.	.2765066	3.080322	4.100307	14
ln_CAI2	within	.	.0369571	3.464773	3.690818	8
ln_CAI2	B/W Variation	.	7.481821	.	.	.
ln_MEAV_SPMWSF_WLA	overall	15.99662	.3127501	15.43638	16.55563	112
ln_MEAV_SPMWSF_WLA	between	.	.3228355	15.45637	16.53091	14
ln_MEAV_SPMWSF_WLA	within	.	.0127482	15.97135	16.02179	8
ln_MEAV_SPMWSF_WLA	B/W Variation	.	25.32406	.	.	.
ln_V1_additions	overall	4.648225	.2910665	4.18834	5.372311	112
ln_V1_additions	between	.	.2864509	4.262525	5.194293	14
ln_V1_additions	within	.	.0885447	4.47473	4.974817	8
ln_V1_additions	B/W Variation	.	3.2351	.	.	.

Appendix 5 – Calculation of composite scale variables (CSVs)

A5.1 In our top-down totex model we are using a composite scale variable (CSV) as the cost driver based on customer numbers and MEAV. We base the weightings in the CSV on the results of regression analysis. This is similar to the approach we adopted as part of DPCR5.

A5.2 There are a number of steps in this approach:

- The first step is to standardise each of the components of the CSV, log MEAV and log customer numbers by subtracting the average of these variables from each observation and dividing by the standard deviation. This standardisation avoids a driver with a large average having an undue effect on the calculation of the weights.

- The next step is to run a multivariate regression including each of the standardised log variables:

$$\log(\text{totex\_excl}) = \text{Intercept} + b_1 \text{Std.}\log(\text{MEAV}) + b_2\ \text{Std.}\log(\text{customer numbers}) + \varepsilon$$

- The weight on MEAV is then $x=b_1/(b_1+b_2)$, similarly the weight on customers numbers is $y=b_2/(b_1+b_2)$.

- The CSV is then calculated using the original un-standardised variables as:

$$\text{CSV} = \text{MEAV}^{x} \ \times \ \text{Customer numbers}^{y}$$

- Or using a log transformation

$$\log \text{CSV} = \text{X} \ \times \log(\text{MEAV}) + \text{Y} \ \times \log(\text{Customer numbers})$$

A5.3 This approach results in a CSV with an 88 % weighting on MEAV and a 12 % weighting on log customer numbers which we have used in the top-down totex regression.

A5.4 In our bottom-up totex analysis we are also using a CSV cost driver. The weights for this cost driver are based on industry spend proportions for the activity level cost areas to which the drivers apply. The weights are presented in Table A5.1. We use the same drivers as is used in the activity level analysis. Where it is not obvious what a suitable driver is, we used such a proxy driver such as number of customers, units distributed or MEAV. It is not necessary to standardise or regress the variables in this instance as they are being weighted by expenditure and as such are in a common format already. This is a similar method to that used in RIIO-GD1.

Table A5.1 Weights used to construct the bottom-up totex driver.

	Activity Area	Identified Driver	Weight
1	Connections	Units distributed	2.9%
2	Diversion	Total length	2.5%
3	Reinforcement	Units distributed	7.5%
4	ESQCR	Overhead LV and HV line length	0.5%
5	Asset replacement	MEAV_SPMWSF	18.2%
6	Refurbishment	MEAV_SPMWSF	2.5%
7	Civil works	MEAV_SPMWSF	2.8%
8	Operational IT&T	Total length	1.4%
9	Non Op Capex	MEAV_SPMWSF	2.4%
10	Legal & Safety	MEAV_SPMWSF	1.5%
11	HVP Asset replacement	Units distributed	0.5%
12	HVP General Reinforcement	Units distributed	0.6%
13	HVP Fault Level Reinforcement	Units distributed	0.6%
14	HVP Legal & Safety	Units distributed	0.5%
15	HVP BT 21st Century	Units distributed	0.4%
16	HVP Other	Units distributed	0.0%
17	Flooding	MEAV_SPMWSF	0.3%
18	Business Support	MEAV_SPMWSF	12.1%
19	BT 21st Century	MEAV_SPMWSF	0.3%
20	CAI	MEAV_SPMWSF	22.5%
21	Losses and other environmental	MEAV_SPMWSF	0.4%
22	NOCs Other	MEAV_SPMWSF	1.0%
23	Tree Cutting	Spans cut	3.1%
24	Black Start	MEAV_SPMWSF	0.2%
25	Inspection & Maintenance	MEAV_SPMWSF	3.9%
26	Troublecall	Total faults	9.5%
27	ONIs	Total ONIs	1.9%
28	Severe Weather 1 in 20	Overhead LV and HV line length	0.3%

Appendix 6 – Totex sensitivities

Random Effects (RE)

A6.1 Ahead of draft determinations we considered the use of an alternative estimation technique, RE. This had been proposed for cost benchmarking in RIIO-ED1 by Frontier Economics based on their initial work for Ofgem and the DNOs.

A6.2 The RE estimator is used in panel data analysis. It is described relative to pooled OLS. The pooled OLS estimator pools total variation within a panel. This variation has two components: *within* variation denotes variation in costs around the average costs for each DNO; *between* variation considers the variation around the set of mean DNO costs. Whereas pooled OLS gives equal weight to these two components of variation, the RE estimator can be viewed as a weighted average of the within and between estimator. It is in this sense that the RE estimator can be interpreted as a Generalised Least Squares estimator.

A6.3 For draft determinations we investigated the use of RE relative to pooled OLS with cluster robust standard errors. This was based on a comparison of modelled costs, efficiency scores, and the parameter estimates from both estimation techniques.

A6.4 Holding all other aspects constant (eg normalisations, time period, same cost drivers), the modelled costs, efficiency scores, and parameter estimates were very similar for the pooled OLS and the RE estimators. These are presented in Table A6.1 below.

A6.5 Based upon these findings we are satisfied that a change in estimator does not generate a fundamentally different outcome, both in terms of parameter estimates but critically the efficiency scores for each DNO. We note that the robustness of the efficiency scores across the two estimators can also be seen by an inspection of the Stata regression output. One of the statistics which Stata reports as part of the RE output is "$\boldsymbol{\rho}$", an estimate of the total variation explained by the company effects. This is close to 0.5 for most regressions, but particularly the two totex models. Given that the weights for the two components are almost the same, then the results using the pooled OLS, which simply sums (without weights) within and between variation, will be similar. The sensitivity results reported in Table A6.1 show that there is very little difference between efficiency scores estimated using pooled OLS and RE.

Table A6.1 Model results for Pooled OLS and Random Effects Estimation

Technique	**Pooled OLS**		**Random Effects**	
Model				
ln_totex_excl =	a + b*ln_bu_csv + b*year	a + b*MACRO_CSV + b*year	a + b*ln_bu_csv + b*year	a + b*MACRO_CSV + b*year
Time period	**2011 - 2023**			
	Bottom up	**Top Down**	**Bottom up**	**Top Down**
ENWL	1988	2040	1991	2043
NPGN	1450	1472	1445	1470
NPGY	1949	1938	1952	1940
WMID	2016	2020	2020	2023
EMID	2213	2254	2221	2259
SWales	1153	1155	1145	1151
SWest	1556	1501	1553	1499
LPN	1635	1689	1633	1688
SPN	1808	1851	1809	1852
EPN	2784	2718	2805	2728
SPD	1691	1700	1690	1700
SPMW	1602	1576	1600	1574
SSEH	1137	1129	1129	1124
SSES	2605	2533	2621	2541
GB Total	**25588**	**25578**	**25614**	**25592**
	Stata output efficiencies			
ENWL	0.95	0.93	0.95	0.93
NPGN	0.98	0.96	0.98	0.97
NPGY	0.95	0.96	0.95	0.96
WMID	1.03	1.03	1.03	1.03
EMID	0.95	0.93	0.94	0.93
SWales	0.94	0.94	0.95	0.94
SWest	1.10	1.14	1.10	1.14
LPN	1.06	1.03	1.06	1.03
SPN	1.01	0.99	1.01	0.99
EPN	1.03	1.06	1.03	1.05
SPD	0.90	0.90	0.90	0.90
SPMW	1.15	1.17	1.15	1.17
SSEH	1.04	1.05	1.05	1.05
SSES	0.93	0.95	0.92	0.95
Coefficient on:				
Driver one	0.83	0.79	0.84	0.80
Driver two	-0.01	-0.01	-0.01	-0.01
_cons	26.65	22.01	26.65	21.97
		ρ =	0.49	0.52

rho (fraction of variance due to u_i)

2013-14 actual data

A6.6 Ahead of final determinations we ran a sensitivity on the use of the 2013-14 updated actual numbers[53].

A6.7 Table A6.2 compares our final determinations results with results using the 2013-14 year actuals instead of the 2013-14 data submitted in March. We are satisfied that the differences are small. The numbers presented below are post application of the UQ, RPE and smart grid savings and after interpolation under the IQI.

Table A6.2 Sensitivity on using 2013-14 actuals (2012-13 prices)

DNO	Final determinations	Sensitivity using 2013-14 actuals	Difference	
	£m	£m	£m	%
ENWL	1,825	1,830	-5.5	-0.3%
NPgN	1,265	1,267	-2.0	-0.2%
NPgY	1,694	1,698	-3.5	-0.2%
WMID	1,851	1,856	-5.5	-0.3%
EMID	1,956	1,957	-0.3	0.0%
SWALES	1,024	1,026	-1.8	-0.2%
SWEST	1,482	1,490	-8.2	-0.6%
LPN	1,771	1,774	-3.4	-0.2%
SPN	1,722	1,724	-1.7	-0.1%
EPN	2,536	2,548	-11.4	-0.5%
SPD	1,519	1,526	-6.5	-0.4%
SPMW	1,667	1,669	-2.3	-0.1%
SSEH	1,121	1,121	-0.1	0.0%
SSES	2,334	2,334	0.8	0.0%
Total	23,768	23,820	-51.4	-0.2%
Total excl WPD	17,455	17,491	-35.5	-0.2%

A6.8 We required the DNOs to resubmit their BPDTs with this new data, on a best endeavours basis. This data conversion process was done quickly by the DNOs, and at the same time we were issuing supplementary questions to the DNOs on this data when we found errors or omissions not present in the main BPDT. This lessened our confidence in using this data source for setting allowances for final determinations.

A6.9 Given that the actual numbers was only changing one year's data along with the minimal changes to modelled costs when using 2013-14 actuals and the potential for error in this submission, we do not use the latest actuals in our analysis.

[53] In draft determinations we used numbers which had been submitted in March 2014 (which contained 2013-14 data up to around January 2014), in July 2014 the annual regulatory submissions was provided by the companies. The annual packs were not cut in the same manner as the BPDTs due to differences related to reporting and cost categorisation in DPCR5 and RIIO-ED1, eg smart meters, betterment for faults/asset replacement, network policy, etc.

Appendix 7 – Asset replacement and refurbishment changes

Appendix summary

This appendix details the issues raised since draft determinations on asset replacement and refurbishment and our response.

Summary

A7.1 The table below summarises the issues raised by each DNO and our response to them.

Table A7.1: Summary of asset replacement and refurbishment issues

DNO	Issue	Ofgem view
Asset replacement		
ENWL	132kV circuit breaker – replacement of outdoor AIS with indoor GIS	Accept - positive adjustment to GIS
NPgN	LV main underground plastic	Reject
	6.6/11kV and 20kV primary circuit breaker	Reject
	6.6/11kV and 20kV pole mounted switchgear - other	Reject
	33kV and 66kV ground mounted transformers	Reject
	66kV circuit breakers (AIS)	Reject
NPgY	LV Main underground plastic	Reject
	6.6/11kV primary circuit breaker	Reject
	6.6/11kV pole mounted circuit breaker	Reject
	6.6/11kV switchgear - other	Reject
	33kV circuit breakers	Reject
	66kV circuit breakers	Reject
	33kV and 66kV GM transformers	Reject
	132kV circuit breakers	Accept - adjustment to GIS
	132kV transformers	Reject
	EHV pole	Accept - adjustment to unit costs
SPN	HV (conventional) overhead line conductor	Accept – positive volume adjustment
	HV (BLX) overhead line conductor	Reject
	132kV overhead line conductor	Accept – positive volume adjustment
EPN	HV (conventional) overhead line conductor	Accept – positive volume adjustment
	132kV overhead line (tower line) conductors	Reject
SPMW	132kV poles	Reject
	132kV switchgear	Reject
	132kV circuit breakers - replacement of outdoor AIS with indoor GIS	Accept - positive adjustment to GIS
	132kV transformers	Reject
SSES	66kV underground cable	Reject

Refurbishment		
NPgN	LV and HV Pole	Reject
	LV switchgear	Reject
	33kV and 66kV pole	Accept - adjustment to unit costs
	132kV overhead line tower (painting)	Reject
	EHV and 132kV transformers	Reject
NPgY	EHV pole	Accept
	LV and HV Pole	Reject
	LV switchgear	Reject
	132kV overhead line tower (painting)	Reject
	EHV and 132kV transformers	Reject
SPMW	132kV tower	Accept - adjustment to unit costs for 275kV towers
SSES	132kV transformer	Reject

Refurbishment error

A7.2 Following draft determinations an error was identified in the calculation of the volume trade-off between asset replacement and refurbishment. The error led to volumes of various assets being omitted from our view of allowed volumes. This error has been corrected. The table below lists the slow-track DNOs and the assets affected.

Table A7.2: DNOs and assets affected by volume calculation error

DNO	Asset volumes affected
ENWL	HV pole
NPgN	66kV transformer, 132kV tower and 132kV transformer
NPgY	33kV pole, 33kV and 66kV transformer and 132kV transformer
LPN	Not affected
SPN	33kV tower
EPN	33kV tower
SPD	Not affected
SPMW	Not affected
SSEH	HV Primary and RMU switchgear
SSES	33kV transformer

ENWL

Asset replacement

A7.3 We make a significant change to ENWL's modelled costs following further review of its 132kV circuit breaker (CB) submissions. At draft determinations we accepted the need to renew the 132kV CBs at each site but contested the replacement of existing outdoor air insulated switchgear (AIS) with indoor gas insulated switchgear (GIS) at two locations, Bredbury and Stanah. We did not allow costs for GIS CB at these sites due to limited information and we were concerned with the timing of the Bredbury project.

A7.4 Following draft determinations ENWL submitted further scheme papers and formal planning and approval papers to justify its move to GIS. We now accept ENWL's request for GIS at both sites. For Bredbury we were concerned that this project was in DPCR5. We are now satisfied that the expenditure, all of its forecast volumes and HI benefits are in the RIIO-ED1 period. For Stanah we accept the need for GIS due to space constraints at the site.

NPgN

Asset Replacement

LV main (UG) plastic

A7.5 NPgN argued that the unit cost disallowance to its LV main (UG) plastic submission is unjustified based on its loss reduction scheme. Its unit cost is high compared to our median benchmark. We reviewed its submissions and further evidence presented and see no reason why these costs should be so much higher than the benchmark. We make no adjustments from draft determinations to our median unit cost benchmark in asset replacement. We already applied an adjustment to both NPgN's and NPgY's LV Main UG plastic additions as part of NPg's loss reduction strategy. Its low loss solution involves the installation of oversize underground cables at LV for all of their LV cable addition in RIIO-ED1. We made this adjustment after our totex and disaggregated modelling because we only have a breakdown of modelled volume in asset replacement and not for areas such as connections or faults.

6.6/11kV and 20kV primary circuit breaker

A7.6 NPgN challenged the unit cost disallowance applied to both its 6.6/11kV and its 20kV primary CBs submission. Its unit costs for 6.6/11kV CB and 20kV CB are high against our benchmarks which are based on the DNO median.

A7.7 At draft determinations, for 6.6\11kV we had a sufficient dataset to calculate a median unit cost, and this was applied to NPgN.

A7.8 For 20kV CBs, NPgN were the only DNO replacing 20kV switchgear in RIIO-ED1. Therefore we did not have a sufficient dataset to calculate an industry median unit cost. In order to set an appropriate unit cost we calculated the difference between NPgN's own 6.6/11kV unit costs and 20kV unit costs and applied this scalar to our view of 6.6/11kV unit costs. This set our view of unit costs for 20kV CBs.

A7.9 In its justification of its 6.6/11kV and 20kV primary CB costs, NPg identified that its plan is based on named schemes of work justified by secondary deliverables and that its costs are based on historical and market tested costs. NPg has questioned the drop in the industry median from DPCR5 to RIIO-ED1 and suggested that other DNOs' unit costs are implausible and that they have not accounted for site specific costs. All DNOs have secondary deliverables attached to this asset so we do not accept this as a justification for high costs. We believe this to be an area where DNOs have focused to drive down their costs. In consultation with the DNOs, we defined the scope of work included as part of the asset replacement activity. The scope as defined in the RIGs sets out all the costs that lie within or outside the cost of replacing the prime asset. The RIGs give assurance that all DNOs are reporting correctly and therefore it is appropriate to benchmark each asset's unit costs. We have reviewed its submissions and further evidence presented and see no reason why these costs should be higher than the benchmark. We make no adjustments from draft determinations to 6.6/11kV and 20kV primary CB unit costs.

6.6/11kV and 20kV pole mounted switchgear (other)

A7.10 NPgN disagreed with the unit cost disallowance to its 6.6/11kV pole mounted switchgear (other) submission. Its unit cost is very high compared to our median benchmark and twice as high as its own historical unit costs. NPg argued that there was a work-mix issue in the reporting of this asset and that the median benchmark was inappropriate. As above the scope as defined by the DNOs in the RIGs sets out all the costs that lie within or outside the cost of replacing the prime asset. We have reviewed its submissions and further evidence presented and see no reason why these costs should be higher than the benchmark or its own historical cost. We make no adjustments from draft determinations.

A7.11 NPgN also challenged our unit costs for pole mounted switchgear (other) at 20kV. Similar to 6.6/11kV, its 20kV unit cost is very high compared to our median benchmark, and three times its own historical unit cost. NPgN are the only DNO to replace 20kV switchgear (other) in RIIO-ED1. Similar to the 20kV CBs, we apply a scalar to the 6.6\11kV costs to set a unit cost for 20kV pole mounted switchgear (other). Based on the same reasons as for its 6.6/11kV switchgear other we make no adjustment from draft determinations for its 20kV assets.

33kV and 66kV ground mounted transformer

A7.12 NPgN disagreed with the unit cost disallowance to its 33kV and 66kV transformers. Its unit costs for both are high against our median benchmarks. It argues that there is a wide spread of costs which illustrate differences in transformer size and the application of consequential asset costs. We have defined the scope of work included as part of the asset replacement activity through the RIGs. The scope as defined in the RIGs sets out all the costs that lie within or outside the cost of replacing the prime asset. We have used the further breakdown of transformer replacement in to ratings as provided by the DNOs in their BPDTs when deciding the unit cost. We make no adjustments from draft determinations.

66kV circuit breaker outdoor air insulated switchgear

A7.13 NPgN argued that the unit cost disallowance to its 66kV CB submission is unjustified. Its unit cost is high against our benchmark which is based the DNO median. NPgN's 66kV outdoor air insulated switchgear is nearly double our view. We agree that there is a small sample for this asset. However our median benchmark is higher than NPgN's historical unit costs. We make no adjustments from draft determinations.

Refurbishment

LV and HV pole

A7.14 NPgN argued that its unit cost disallowance to LV and HV pole refurbishment at draft determinations was unjustified and provided further supporting evidence. We have reviewed its submissions and further evidence presented and see no reason why its LV and HV should be higher than the benchmarks. The benchmark is based on the difference of the DNO's own replacement unit cost against its refurbishment unit cost and then a median is taken across all DNOs and applied to the asset replacement expert view. There is a reasonable sample and we believe our benchmark, which was reviewed by our technical consultants is robust. We make no adjustments from draft determinations.

LV pillar switchgear

A7.15 NPgN raised concerns with the unit cost adjustment applied to its LV pillar indoor and outdoor refurbishment allowance. It highlights that not many DNOs carry out these activities. The benchmark was set by our technical consultants based on DNO data and their own expert knowledge. We do not accept NPgN's argument based on the fact that its refurbishment cost is over 70% of its asset replacement cost for the activity. We deem these costs to be too high and make no adjustment from draft determinations.

33kV and 66kV pole

A7.16 NPgN argued that the unit cost disallowance to EHV pole refurbishment at draft determinations was unjustified and provided further supporting evidence. We accept that NPgN's bespoke woodhouse masts have a unique design and are different to standard wood poles. These masts are categorised as wood poles under the RIGs. However they are more akin to lattice towers and the refurbishment costs associated with the woodhouse masts is greater than that of EHV wood poles. We have adjusted NPgN's unit cost to account for woodhouse masts.

132kV tower

A7.17 NPgN disagreed with our unit cost disallowance for 132kV tower painting at draft determinations. It is receiving a significant uplift to its 132kV tower refurbishment and tower foundation work, which is lower than our benchmark unit costs. We have reviewed its submissions and further evidence presented and see no reason why its 132kV tower painting costs should be higher than the benchmarks. We make no adjustments from draft determinations.

EHV and 132kV transformer

A7.18 NPgN argued that its volume disallowance to its EHV and 132kV transformers was unjustified. Despite receiving significant reward for its low unit costs when compared to our benchmark it still receives a reduction due to high volumes compared to our view. NPgN argue that its refurbishment falls into two groups; major mid-life refurbishment and minor refurbishment. We have reviewed its submissions and further evidence presented and see no reason why its volumes are so high. NPgN's health index movements over RIIO-ED1 for these assets are not sufficient to justify its arguments. We make no adjustments from draft determinations.

NPgY

Asset replacement

LV main (UG) plastic

A7.19 As in NPgN we do not make an adjustment to our benchmark unit cost based on its loss reduction solution but have applied an overall adjustment to reflect all of its LV main additions.

A7.20 NPgY argued that we have made an unjustified reduction to its proposed LV main UG plastic volumes. It provided further detail and suggested we review previously provided evidence. Following a review with our technical consultants we do not make any changes from our draft determinations decision. NPgY's indicate continuation of its current DPCR5 policy and we see no reason for the increase in volume in RIIO-ED1.

6.6/11kV primary circuit breakers

A7.21 NPgY, like NPgN disagreed with our unit cost disallowance to its 6.6/11kV primary circuit breakers. Its arguments and our response to them is the same as above for NPgN (paragraph A7.6-A7.7).

6.6/11kV pole mounted circuit breakers

A7.22 NPgY argued that we have made an unjustified reduction to its proposed HV pole mounted circuit breakers volumes. NPgY has provided further detail and highlighted evidence it previously provided. NPgY argued that in our draft determinations we incorrectly stated that NPgY includes auto-recloser batteries in its HV pole mounted CB costs. We are happy that NPgY correctly allocates its auto-recloser batteries in the protection cost category. However, we do not accept the volumes proposed. Our view of the average age of these assets is lower than NPgY and we do not consider it is reasonable to replace the volumes proposed.

6.6/11kV pole mounted switchgear - other

A7.23 NPgY, like NPgN, argued that the unit cost disallowance to its 6.6/11kV pole mounted switchgear (other) submission was unjustified. Its arguments and our response to them are the same as above for NPgN (paragraph A7.8-A7.9).

33kV circuit breaker

A7.24 NPgY disagreed with our unit cost disallowance to its 33kV CB submission. Its unit cost is high against our median benchmark. NPgY argue that the CB being replaced is not industry standard and carry extra consequential costs. We reject this argument in this area as the scope, defined in the RIGs, sets out all the costs that lie within or outside the cost of replacing the prime asset. We have reviewed its submissions and further evidence presented and do not believe these costs to be atypical. We make no adjustments from draft determinations.

66kV circuit breaker

A7.25 NPgY argued that the unit cost disallowance to its 66kV CB submission is unjustified. Its unit cost is high against our benchmark which is based the DNO median. NPgY's 66kV outdoor AIS is more than twice our benchmark unit cost, based on the median and higher than its own 132kV outdoor AIS. We agree that there is a small sample for this asset. However the median is in line with NPgY's historical unit costs. We make no adjustments from draft determinations.

33kV and 66kV ground mounted transformers

A7.26 NPgY, like NPgN, argued that the unit cost disallowance to its 33kV and 66kV ground mounted transformers is unjustified. Its arguments and our response to them is the same as above for NPgN (paragraph A7.12).

132kV circuit breakers

A7.27 We made a significant change to NPgY's draft determinations modelled costs. This follows further review of NPgY's 132kV CB submissions. At draft determinations, we accepted that NPgY needed to renew its 132kV CBs at each site but contested the replacement of existing outdoor AIS with indoor GIS at Grimsby West. We did not allow costs for GIS CB at this site due to limited information. After draft determinations NPgY submitted further evidence. Following a review in conjunction with our engineering consultants we accept that GIS is justified based on the site constraints requiring indoor GIS.

132kV transformers

A7.28 NPgY raised concerns with the unit cost reduction being applied to its 132kV transformers. We believe the benchmark unit cost to be robust. It was informed by a further breakdown of 132KV transformers ratings (sizes) provided within the BPDTs and reviewed by our technical consultants. We make no adjustments from draft determinations.

EHV pole

A7.29 NPgY questioned our view of its EHV pole replacement modelled costs at draft determinations and provided further supporting evidence. For the same reasons given for the refurbishment of woodhouse masts for NPgN, we adjust NPgY's EHV pole unit costs.

Refurbishment

EHV pole

A7.30 We make the changes to NPgY's EHV pole replacement unit costs because we have uplifted unit costs for its asset replacement unit costs to take account of its wood house masts. We make this change because our unit costs for refurbishment are based on our asset replacement unit costs.

LV and HV pole

A7.31 NPgY, like NPgN, questioned our view of its LV and HV pole refurbishment modelled costs at draft determinations and provided further supporting evidence. Its arguments and our response to them is the same as above for NPgN (paragraph A7.14).

EHV tower

A7.32 NPg highlighted an error in draft determinations that it was not receiving its tower refurbishment volumes which were supported by its submitted health index within the BPDT. We correct this error.

LV pillar switchgear

A7.33 NPgY, like NPgN, raised concerns with the unit cost adjustment applied to its indoor and outdoor LV pillar refurbishment allowance. Its arguments and our response to them is the same as above for NPgN (paragraph A7.15).

132kV tower

A7.34 NPgY, like NPgN, questioned our view of its 132kV tower painting modelled costs at draft determinations and provided further supporting evidence. Its arguments and our response to them is the same as above for NPgN (paragraph A7.17).

EHV and 132kV transformer

A7.35 NPgY, like NPgN, questioned our view of its EHV and 132kV transformer modelled volumes at draft determinations and provided further supporting evidence. Its arguments and our response to them is the same as above for NPgN (paragraph A7.18).

SPN

Asset replacement

A7.36 SPN questioned our view of its overhead line conductor volumes at draft determinations. Our view was that SPN's submissions for HV (conventional and BLX) and 132kV (tower line) conductor were too high based on its historical replacement volumes. UKPN provided further information. This identified that its low volumes of replacement in DPCR5 were due an extensive ESQCR programme in this period. We reviewed historical replacement volumes with our technical consultants using DPCR4 and DPCR5 volumes. We accept SPN's HV conventional and 132kV (tower line) conductor volumes based on evidence provided. But we do make an adjustment to our draft determinations view of HV BLX conductor volumes for SPN as our volumes are more in line with its DPCR4 volumes.

EPN

Asset replacement

A7.37 Like SPN, EPN questioned our view of volumes for HV conventional and 132kV (tower line) conductor volumes. For the same reason as SPN we accept EPN's HV conventional conductor volumes. We do not adjust its 132kV (tower line) conductor volumes from our draft determinations because we believe the decision at draft determinations volumes is in line with its DPCR4 volumes.

SPMW

Asset replacement

A7.38 SPMW raised concerns regarding reductions to its submitted costs for 132kV assets. We accepted most of SPMWs 132kV asset replacement volumes at draft determinations but our view of unit costs was lower than SPMW's view. This concerned the following assets:

- 132kV overhead lines (pole line) conductors;
- 132kV overhead line (tower line) conductors;
- 132kV poles;
- 132kV switchgear;
- 132kV transformers; and
- 132kV circuit breakers.

A7.39 SPMW provided supporting evidence following draft determinations for each of the above. We reviewed this evidence alongside our engineering consultants.

A7.40 SPMW argued that 132kV non-load-related project expenditure should be identified and assessed individually using scheme specific costings. We disagree. In consultation with the DNOs, we have defined the scope of work included as part of the asset replacement activity through the RIGs. The scope as defined in the RIGs sets out all the costs that lie within or outside the cost of replacing the prime asset. We consider that the unit costs as defined are appropriate and we note that no other DNOs have proposed that 132kV non-load-related should be considered on a scheme-by-scheme basis.

A7.41 We provide further detail on each of these asset classes below.

132kV OHL (pole line) conductor

A7.42 SPMW's fast-track unit cost for 132kV OHL (pole line) conductor was far lower than our benchmark (based on median unit cost). In its slow-track submission its costs were four times more expensive than at fast-track and three times more expensive than our benchmark. We reviewed its submissions, further evidence presented and responses received from supplementary questions. SPMW stated that the change in its unit costs were due to it incorrectly allocating OHL (tower line) conductor to OHL (pole line) and this led to the lower unit cost at fast-track. It said that its higher unit costs are atypical as they relate to the complete replacement of an existing line. We discussed this with our engineering consultants and we do not consider that this type of work is an atypical. We make no changes to our approach from draft determinations.

132kV OHL (tower line) conductor

A7.43 At draft determinations SPMW received a significant reduction to its 132kV OHL (tower line) conductor unit costs when compared to our benchmark (based on median unit costs). It stated that this adjustment should be reversed to ensure successful delivery of its secondary deliverables. Based on the evidence presented by SPMW, we do not consider it has provided sufficient justification as to why its unit costs should be higher. We make no changes from draft determinations.

132kV pole

A7.44 SPMW's replacement cost for a 132kV pole was over four times higher than our benchmark (based on median unit cost) at draft determinations. Its unit cost doubled between its fast-track and slow-track submissions despite very little change in its volumes. It stated that this change was related to its atypical work of replacing a complete 24km line. As for OHL (pole line) conductors, we have reviewed the evidence provided by SPMW and do not consider that the costs are atypical. Therefore, we see no reason why these unit costs should be higher than the industry median and make no changes from draft determinations.

132kV switchgear (other)

A7.45 Following draft determinations, SPMW resubmitted its 132kV switchgear (other) volumes based on the correct interpretation of the BPDT RIGs. It raised concerns following draft determinations due to the significant reduction it received against our unit cost benchmark. We have reviewed the submitted evidence, alongside a review of the RIGs, to better understand and make sure our benchmark unit cost was appropriate. Based on our data and that of our technical consultants we believe our benchmark (based on median unit cost) unit cost remains appropriate. We make no adjustment from draft determinations.

132kV transformers

A7.46 SPMW was concerned with the unit cost reduction applied to its 132kV transformers. It argued that we did not take account of atypical replacements and the varying size of 132kV transformers when setting the benchmark unit cost. We believe the benchmark unit cost to be robust. As we note above for NPgY (paragraph A7.27), it was informed by a further breakdown of 132kV transformers ratings (sizes) provided within the BPDTs and reviewed by our technical consultants. We note that the median unit cost is higher than the SMPW's unit cost submitted at fast-track and the reason SPMW face a reduction to the submitted slow-track costs is due to a significant increase in its unit costs from its fast-track submission. Given the lack of supporting evidence provided by SPMW and our review of the unit costs we make no changes to our view at draft determinations.

132kV circuit breakers

A7.47 We make a significant change to SPMW's modelled volumes for 132kV CBs from draft determinations. At draft determinations we accepted that SPMW needed to renew its 132kV CBs at a number of sites. We accepted the replacement of outdoor AIS with indoor GIS CBs at Birkenhead based on space constraints but we contested the same replacement at Crewe and Lister Drive.

A7.48 Following draft determinations SPMW submitted further information to justify its move to a GIS at these two sites. This included CBAs for AIS inline and AIS offline solutions as well as GIS solutions. Based on the CBA we accept the volumes of GIS CBs submitted by SPMW.

Refurbishment

A7.49 As with asset replacement, SPMW believe that 132kV refurbishment expenditure should be assessed using scheme specific costings. It highlighted that its 132kV overhead line refurbishment is limited to 16 circuits each of which involves site specific conditions, including:

- road and river/canal crossings, each requiring scaffolding during conductor replacement
- other overhead line crossings, again with scaffolding or temporary diversion requirements
- the ratio of tension to suspension towers will be dictated by the local geography
- the differences between single-circuit and dual circuit costs.

A7.50 We reviewed the evidence alongside our engineering consultants and do not agree with SPMW. We believe that all DNOs face similar conditions and we are already taking account of them within our benchmark view.

A7.51 SPMW challenged our modelled costs for refurbishment of its 132kV overhead line towers. It identified that SPMW has a legacy issue where tower lines are built to 275kV specifications and retaining the line at 275kV is the most cost-effective option. SPMW identified 77 275kV towers which cannot be refurbished for the same cost as a 'normal' 132kV tower. After discussing with our engineering consultants, we accept this argument. To account for this we apply a specific 275kV tower replacement unit cost. This is based on Ofgem's transmission data, which was reviewed by our technical consultants.

SSES

Asset replacement

66kV underground cable

A7.52 SSES argued that the unit cost disallowance to its 66kV underground cable submission is unjustified. Its unit cost is high against our benchmark which is based the DNO median and reviewed by our technical consultants. We agree that there is a small sample for this asset. However, we do not agree that SSES's costs for 66kV cable replacement should be four times its 33kV cable unit costs. We make no adjustments from draft determinations.

Refurbishment

132kV transformers

A7.53 SSES disagreed with the unit cost disallowance to 132kV transformer at draft determinations. We reviewed its submission again and the further evidence provided. We see no reason why its 132kV costs should be higher than the benchmark. The benchmark is based on the difference of the DNO's own replacement unit cost against its refurbishment unit cost and then a median is taken across all DNOs and applied to our view of asset replacement unit costs. There is a sufficient sample and we believe our benchmark is robust. We make no adjustments from draft determinations.

Appendix 8 - Age based asset replacement model

Volume assessment

Age-based model

A8.1 All assets with an age profile were subjected to the age-based model. The model used two sets of disposal values rather than one to infer asset lives. We used the aggregate age profile across all DNOs. The first was based on actual replacement volumes in the DPCR5 period (2010-11 to 2013-14)[54] and the second was based on the forecast replacement volumes for the last year of DPCR5 and all of RIIO-ED1 (2014-15 to 2022-23)[55]. The two implied lives gave different estimates for replacement volumes. Both profiles offered valuable information and we could not find sufficient objective reasons to choose one over the other, so we used both.

A8.2 We assessed each DNO's forecast volume against the modelled volumes. Where a DNO's forecast volumes were below our modelled volumes, the DNO received its own volumes. Where a DNO's forecast volumes were above our modelled volumes, the DNO either received its own volumes, the average between the two modelled volumes or the average of the lowest modelled volume and its own forecast volumes (see Table A8.1). The final volumes received depend on the outcome of a line-by-line qualitative assessment.

Table A8.1: Asset volumes use in assessment

Scenario	**Volumes use**
1. DNO forecast volumes below both profiles modelled volumes	DNO volumes
2. DNO forecast volumes above either or both profiles modelled volumes	Following further review of each of the DNO's supporting evidence one of the following: a) DNO volumes b) the average between the two age profiles c) the average of the lowest modelled volume and the DNO's proposed volume

A7.54 We placed significant emphasis on the qualitative review for draft determinations.

A8.3 Where the DNO's forecasts were above either profile's modelled volumes (ie scenario two in Table A8.1), three key questions were considered:

[54] Age profile 4.
[55] Age profile 6.

1. Had the DNO proposed using a substitute asset, eg plastic underground cables for paper underground cables?
2. Had the DNO provided additional evidence as to why the volumes were higher, eg a higher level of deterioration than age would indicate?
3. Were there complementary assets which have been allowed, eg LV poles for LV conductor?

A8.4 For the substitution of an asset, we considered the following questions:

- Had the DNO indicated lower disposal volumes than replacement volumes (indicating that it is disposing of assets elsewhere)? If the disposals were lower than replacement volumes was the aggregate modelling volume for the substitutes greater than the DNO's proposed replacement volumes?
- If aggregate volumes were not sufficient were there other reasons to increase volumes?
- If proposed volumes were accepted has sufficient evidence (eg a CBA) been supplied to support any higher unit costs?

A8.5 If the asset class did not have readily identifiable substitutes and the DNO's proposed volumes were higher than indicated by the modelling, we undertook the following:

- in most cases a review of the run rate and qualitative evidence by our engineering consultants
- an assessment of evidence provided by the DNO supporting the higher volumes
- a comparison of whether the asset life provided by the DNO was significantly different from the all DNO average life (ie we were less willing to accept a greater volume if the DNO proposed a significantly shorter life than on average)
- a check to determine whether there were complementary assets, ie LV poles and OHL conductors.

A8.6 Following this review, if we were satisfied the DNO could justify the volumes, we allowed the submitted volumes.

A8.7 If we were not satisfied, where both age profiles provided volumes lower than the DNO submitted volumes, we set the volumes as the average between the two. Where one age profile is above the DNO's proposed volume, the average of the lowest modelled volume and the DNO's proposed volume was taken.

A8.8 We also had some concerns that the models overestimated the volume for some asset classes which had low volumes. Where this occurred for low value assets (eg unit cost below £30,000), we accepted the DNO's forecast. For higher value assets (eg 132kV transformers), we cross-checked with the health indices and refurbishment data to determine the needs case and applied an adjustment where the health indices supported doing this.

A8.9 We assumed that the DNOs would have built in some uncertainty into their asset forecasts and therefore we did not consider it appropriate to base our volume allowance on an estimate higher than the DNO's submitted volumes. We considered that it is a pragmatic approach given the difference in age profiles and the DNOs' ability to trade-off between refurbishment and replacement.

Non-modelled volumes

A8.10 We continued to use trend analysis and run rates to review the DNO submitted forecast volumes for a number of asset categories where there were no age profiles. For the non-modelled volumes we used trend analysis to review the DNOs submitted forecast volumes for a number of asset categories not suitable for the age based model, eg where there were issues over the data or the spread of the implied asset lives was very large. In such cases we used replacement run rates based on submitted disposal volumes as a proportion of DNO assets in service. In most cases we applied the industry median benchmark to represent efficient replacement volumes. Due to the variable quality of the asset replacement data submitted by DNOs we applied our view of benchmark replacement volumes for some asset categories taking into account the industry median and other supporting information.

Appendix 9 – Consultant report: company specific factors

INTRODUCTION

DNV GL carried out a review of Regional Cost Justification, which were submitted by five DNOs: LPN, SSEH, SPMW, NPgY, NPgN as part of their 2015 -2023 Business Plans. The documents sets out DNO's views on the additional costs they incur as a result of operating in their region, as a result of external conditions and special characteristics of the networks. DNV-GL reviewed the information provided and provides a summary of their final view and the related justification. This report will focus on the areas where the proposed claim was reduced or disallowed.

UK POWER NETWORKS

Central London Network Strategy

UKPN claimed a total additional annual cost of £11.2m p.a. to provide an improved level of network security and response in Central London. A key part of the claim for extra cost was the establishment of a 24/7 operational presence, which was costed at £3.8m p.a. DNV GL agreed that there is a credible case for a central London located operation, to replace the normal out of hour's provision, since most operational staff will live in the less-costly suburbs. DNV GL initially challenged the annual amount claimed, the ASR report "LPN CLA I&M and Faults" stated that current costs for managing faults in Central London are £2.7m p.a. which indicated that the additional annual increase in costs were £1.1m p.a. However, following Ofgem' s draft determination, UKPN indicated that information they had provided in the ASR report was wrong and that £3.8m p.a. represents the incremental cost of enhancing network performance through the establishment of the operational centre. To support this claim UKPN provided a current breakdown of staff and compared this with the total numbers required to enable 24/7coverage. DNV GL agreed with UKPN's assessment; however, since there are significant numbers of positions to be filled, it is unlikely that the operational centre will be fully staffed during 2015. DNV GL recommended that Ofgem allow only 80% of the requested allowance in the first year of RIIO – ED1.

UKPN identified further additional costs of £600k p.a. to carry out enhanced inspection and pro-active maintenance of its Central London assets. DNV GL's view was that the company had not taken into account the synergies with the new operational unit and that enhanced inspection and maintenance work could be performed by the new operational staff to a large degree. Furthermore, an additional amount for increased link box inspection has been separately claimed under a separate category (see Operations, below) and that this appeared to have been double-counted by UKPN. The cost was disallowed.

UKPN had identified additional indirect costs of £2.5m p.a. to support the new operational centre. The amount includes provision of senior authorised staff and admin assistants. DNV GL considered that the amount claimed was too high compared to the direct costs of the organisation. Furthermore, most DNOs are achieving cost savings by devolving some SAP responsibilities to its craftsmen and reducing direct supervision and admin costs, and there will also be a reduction in the indirect costs already provided by the current organisation. DNV GL recommended that the claim be reduced to £440k p.a.

UKPN had claimed £4.3m p.a. to install additional automation and unit protection. They provided well-described justifications for additional automation and DNV GL found the overall claim of £1.21m p.a. for additional automation to be reasonable, but recommended that LPN's CML target should tighten as a result of this project. In regards to the Unit protection, UKPN's assessed costs to convert feeder groups to unit protection without detailed cost breakdowns. DNV GL used unit costs submitted by UKPN for the ED1 period and increased these by 20% to allow for developmental and unit protection costs. Based on the above DNV GL recommended UKPN's claim to be reduced to £1.5m p.a., and that actual costs are assessed as the schemes progress. DNV GL also recommended that LPN's CML and CI targets should tighten as a result of this project.

Transport and Travelling

UKPN claims that the cost of servicing LPN vehicles is almost 45% higher than the cost of servicing vehicles in EPN, resulting in additional costs of £0.1m p.a. DNV GL considered this to be excessive and expected the difference to be no greater than that indicated by the ONS derived labour cost indices ie around 20%. This would reduce the annual additional expenditure to £0.045m.

UKPN claimed that plant and equipment often needs to be moved and delivered overnight to avoid traffic congestion. Whilst there is merit in this claim, DNV GL considered that the additional cost compared to non-London areas appeared high at £0.07m pa and should be better supported by further details of costs incurred, and recommended a reduction to £0.05m pa.

Excavation

UKPN claimed that the cost to UKPN of Lane rental and permit charging for the first year of operation was £1.61m p.a. DNV GL found that the additional costs associated with permits had been separately assessed (see below) and has been double counted. DNV-GL proposed to reduce the claim to £1m p.a. UKPN has assessed the additional cost of operating the expensive London rates for Permits as £572k p.a. It had assessed this figure by comparing the cost of permits per square km of area across their 3 regions, and benchmarking LPN's permit costs against those of SPN. DNV GL did not consider this to be a totally reliable methodology since it fails to factor in any differences in activity levels eg cable repairs per square km. A more reliable assessment would be based on permit costs per excavation. Furthermore DNV GL considered that the timing of some activities is under UKPN's control (eg Capital program works) and it is possible to minimise the impact of permit costs with better planning. DNV GL recommended a reduction to £400k pa.

UKPN had assessed a cost of £450k for additional traffic management obligations. The data provided, which quantified the number and type of traffic management schemes required over an unspecified period, did not indicate the relative costs of such measures, nor did it make comparisons with other regions to support the claim that these measures are more onerous on UKPN than any other DNO. DNV GL considered that the case had not made for additional cost requirements, and that it be rejected.

Operations

UKPN has a dedicated team of 3 staff who are responsible for maintaining a set of keys to 1150 buildings housing secondary substations in the LPN area. The provision of this service costs £105k p.a. Because of the nature of LPN's substation locations in the more central parts of London, DNV GL accepted the need for additional provision and agreed the average cost per substation of around £100 p.a.

UKPN claimed the additional cost to inspect, maintain and replace the ventilation equipment in secondary substations is £141k p.a., which was not supported by any evidence of costs incurred. DNV GL did not accept that this should be treated as a special London factor. The affected substations were originally designed for underground locations and they should be able to operate within these design parameters.

As UKPN has a considerable number of substations below ground level, they are very susceptible to flooding either from ground water or from burst water mains. UKPN claimed an additional £500k p.a. to deal with the disposal and clean-up operations in the event of flooding. DNV GL accepted that this is a genuine issue but considered that the estimate had not been supported by clear evidence of actual incurred costs, and recommended that the claim be reduced to £350k p.a.

Due to the large amount of utility equipment in the ground in close proximity to LPN's LV and HV cables, its more congested footpaths and roadways and greater volumes of street works by other Utilities and their contractors, UKPN claim that there is a greater opportunity for 3rd party cable damages. UKPN has assessed an additional annual amount of £2.6m p.a. by comparing LPN unrecovered cost/km² with that of EPN. DNV GL agreed that there is merit in the claim that there is a higher cost associated with 3rd party damage in the LPN area but did not agree with the way that UKPN had calculated the impact. Based on the figures provided, it was clear that the number of damaged cables in LPN is the lowest amongst the 3 UKPN licence areas. The fact that normalised number of damages is highest in London is mainly due to the fact they operate in a much smaller and denser area and DNV GL considered that UKPN had not used an appropriate metric to support their claim. DNV GL recommended that the claim be reduced to £1m p.a.

The 11,000 link boxes in the LPN Interconnected areas have an inspection frequency of 4 years, compared to a frequency of 8 years in other parts of UKPN. The inspection and maintenance of the 11,000 link boxes is carried out by 5 x 2 man dedicated field crews at an additional cost of £385k pa. DNV GL accepted the need for increased link box inspection in London's interconnected LV network; however they considered the incremental cost of carrying this out to be excessive. The additional workload is 2,750 link boxes p.a. and DNV GL assessed that this should require 1 FTE 2 man team, inspecting circa 12 boxes per working day, at an annual cost of £77k.

UKPN claimed that additional trip testing of circuit breakers is unique to the LPN area as none of the other UKPN regions have an interconnected HV & LV system. They estimated additional costs of £250k p.a. which equates to a cost of £125 per trip test. DNV GL agreed the need for additional trip testing but considered that the assessed cost was excessive. DNV GL assessed the additional cost to be around £120k p.a.

London suffers about 500 HV faults each year. Whilst most faults are repaired at average costs similar to those in EPN and SPN UKPN claimed that some faults incur exceptional repair costs due to technical and environmental factors unique to London. To illustrate the variability of HV cable repairs and the amount of work necessary they provided examples of HV cable faults and estimated the London Factors repair cost of £810k p.a. DNV GL agreed that some faults will incur exceptional costs due to unique London factors, however their claim for £810k of additional costs implies that 20% of faults are uniquely more costly; DNV GL considered this to be too high a proportion and recommended that the claim be reduced to £400k p.a.

UKPN analysed the overtime costs of their EHV field crews and Engineers to support their claim that the majority of their overtime is dictated by the availability of circuits. This amounted to a claimed cost of £785k p.a. Although DNV GL accepted that the circuit loading in London may make the situation more acute, nevertheless they considered that this is a feature that is not unique to London, and that all other DNOs will incur overtime costs associated with outages to varying degrees.

UKPN claimed that the additional costs of repairing EHV cable faults in the LPN Region that are very deep and in congested footpaths are £520k p.a. DNV GL did not think that enough evidence had been presented to substantiate this claim; whilst they accepted that cable disposition in central London areas will incur additional costs, this is not unique to London and DNV GL recommended that, as per their recommendations for HV cables, the allowance be scaled back to £200k pa.

The annual cost of track possession and restricted access to HV & EHV cable systems alongside or bridging over railway property was assessed by UKPN as £877k. DNV GL thought that this is not a unique issue for London, nor for any other part of UKPN; other DNOs will face similar situations and similar costs. DNV GL recommended that the claim be rejected.

UKPN claimed that the additional cost to operate, inspect and maintain the large number of complex underground and or restricted space Primary Substations is circa £345k pa. DNV GL was not clear how the company had quantified this claim, and no breakdown of the extra cost had been provided. DNV GL accepted that in London there is a requirement to construct underground substations which will have higher O&M cost, however the claimed amount appeared excessive. In some cases third parties are contributing towards the cost associated with new equipment/solutions eg Tate modern contributed towards design, development and installation costs; there was no evidence that this had been taken into account. DNV GL recommended that the unique additional cost be reduced to £217k pa.

Security

UKPN also claimed that it is often necessary to reschedule planned works in the area and divert staff away from the congested roads, and that these unplanned de-mobilisations and subsequent re-mobilisations cost circa £125k pa. DNV GL was not clear how they had arrived at this figure and they considered that the case for additional cost had not been made, and should be rejected.

SCOTISH POWER MANWEB

Load-related (all voltages)

SP Manweb commissioned consultants to estimate the incremental cost of load-related reinforcement on their interconnected networks, one using a top down analysis, the other a bottom up approach. Each consultant estimated an increase in costs compared to those of typical radial networks, and SP Manweb took the lower of the 2 estimates and applied the uplift to the 132/33 and 33/11 elements of its load-related plan. DNV GL agreed with the principle that SPMW interconnected network will be more costly to reinforce than equivalent radial networks, and the incremental cost estimates of £22.1m over ED1 provided in the consultants' papers appeared reasonable.

For the longer term DNV GL challenged the assertion that the interconnected network should be perpetuated; although it would be impractical to move rapidly to a radial design within the life of ED1, nevertheless DNV GL would expect to see a cost/benefit analysis of moving towards radial networks at the fringes, and this should include analysis of the cost benefit of allowing network performance (CI and CML) to move towards national averages over the long term.

33kV Asset modernisation capex

SP Manweb had estimated the reduced number of primary transformer changes that would be required on an equivalent radial network, and compared this to its planned transformer replacement programme for the SP Manweb area. DNV GL considered this to be a reasonable approach that properly takes into account the overload capacity available on transformer nameplate ratings as well as the lower unit costs for interconnected network transformers. DNV GL therefore agreed with SP Manweb's estimate of £5.7m.

SP Manweb claimed additional costs for the replacement of ground mounted 33kVcircuit breakers at primary substations, at a cost of 7.8m over the ED1 period. DNV GL agreed that these items are an inherent part of a unit protected 33kV network such as Manweb's and that they would not usually be present at the primary substation on an equivalent traditional radial network.

SP Manweb had compared the cost of replacing pilot circuits on its interconnected network with the cost of replacement on an equivalent radial network within SPD, to estimate an incremental cost of £3.23m over the ED1 period. DNV GL agreed that, due to their interconnected network, SP Manweb has more 33/11kV substations than an equivalent radial network. SP Manweb had calculated the ratio of the number of their 33/11kV substations to those in SPD (1.89) and all other DNOs (2.52) and had used the lower of these figures (1.89) to assess the additional replacement cost. DNV GL agreed with this approach.

SP Manweb claimed additional ED1 costs of £23.2m for the BT21CN programme associated with its 33kV network. As for pilot wires (above) we consider that SP Manweb has under estimated the extent of 33kV pilot circuits on traditional networks. In addition we are unclear why there is no spend in this area in DPCR5 and in ED1 volumes increase significantly. If we use average number of circuit proposed to be migrated from BT across all DNOs we recommend that the regional factors added cost be reduced from 23.2m to 18m. (SPMW claim is based on difference in volume and this needs to be taken into the account during the assessment of BT21 submission element to avoid double counting).

DNV GL agreed with SP Manweb's claim for an additional cost of £4.2m over the ED1 period for general protection costs, which was assessed from a comparison with an equivalent radial network, since the unit protection design of the 33kV network means that there will be increased volumes of these assets.

Other 33kV capex

SP Manweb's claim for additional cost associated with the black start resilience programme at primary substations was based on the higher number of primary substations on their interconnected network, 415 compared to 255 on an equivalent radial network in SPD; using the UCI for black start modifications they claimed an additional £0.9m over the ED1 period. DNV GL agreed that SP Manweb incurs additional costs due to the higher number of substations, but would have expected to see some reduction due to the inherent better reliability of their network, ie they may not need to make every primary fully resilient. DNV GL recommended a reduced additional cost of £0.75m.

SP Manweb claimed additional expenditure due to the higher number of RTUs compared to a radial equivalent network. DNV GL found a small error in their submission (they state 386 assets in SPD's radial network but their calculations are based on 380) but more importantly DNV GL could not see why the ratio of RTUs at primaries (SP Manweb divided by SPD equivalent network) differed so greatly from the ratio of primaries (2.19 versus 1.63). DNV recommended that the lower ratio (1.63) be applied, and that the claim be reduced to £3.4m.

Similarly, SP Manweb based its claim for extra cost for Ethernet communications and infrastructure capex on the ratio of assets in the SPM interconnected network to an equivalent SPD network, and had used a ratio of 1.73 to estimate additional costs of £4.7m. DNV GL re-calculated using the ratio of primaries (1.63) and recommended that the claim be reduced to £4.2m.

DNV GL agreed that SP Manweb will incur extra substation civil costs due to the higher number of substations on an interconnected network. DNV GL agreed with the assessment of the number of additional assets; however there was insufficient evidence that the UCI of civil works was higher in SP Manweb, as they had claimed. DNV GL used the lower UCI at SPD, to recommend that the claim be reduced from £6.4m to £5.7m.

HV non-load expenditure

SP Manweb claimed additional costs associated with the replacement of 11kV X type RMUs. DNV GL agreed the additional unit cost of the X type RMU, which was itemised in SP's unit cost manual, due to the unit protection assets that it includes and they agreed that the additional cost of £7.4m was reasonable.

SP Manweb had used the same approach to assess the extra cost associated with the replacement of X type 11kV to LV transformers, and DNV GL agreed that the claim of £0.2m was reasonable. DNV GL agreed that secondary substations on a unit protected X type network require tripping and RTU batteries that would not normally be required in a traditional radial network substation, and agreed SP Manweb's claim for an additional £1m of replacement costs over the life of ED1.

SP Manweb based its claim for additional substation civil costs of £10.1m on the higher number of brick built secondary substations that are required on a unit protected network. Whilst DNV GL agreed that additional brick built substations will need works, they considered that the claim should be reduced to reflect the lower number of non-brick sites that will need investment and therefore recommended that the claim be reduced to £7.5m.

33kV opex

DNV GL agreed with SP Manweb’s claim that 33kV circuit breakers are not a feature of traditional network primary substations, and that therefore the cost of inspection and maintenance of these assets incurs an additional regional cost of £2.2m.

SP Manweb compared the cost of repairing pilot circuits on its 33kV interconnected network with the cost of repairs on its radial SPD network, to estimate an incremental cost of £3.4m. DNV GL agreed that the volume of pilot circuits will be higher on SP Manweb’s interconnected network, but recommended a reduction in the claim to £2m, following a re-calculation of the comparative costs between the SP Manweb and SPD networks.

Similarly, DNV GL recommended a reduction in SP Manweb’s claim for additional costs for fault repairs on rented 3rd party pilots, from £2.1m to £1.4m.

SP Manweb based its claim for an additional £1m for 33kV cable faults on a higher UCI for repairs compared to SPD, due to the higher fault levels on an interconnected network. Although DNV GL agreed that higher fault levels might lead to higher costs they did not agree that this factor alone accounted for SP Manweb’s high costs and therefore recommended a reduction in the claim to £0.6m.

HV opex

DNV GL agreed with SP Manweb that there are additional I&M costs associated with 11kV interconnected network, because the interconnected network requires HV circuit breakers at each secondary substation to allow for the application of its unit protection policy. DNV GL agreed with SP Manweb’s assessed additional costs of £2.1m, which was based on a comparison with SPD’s radial network.

LV opex

SP Manweb claimed that it incurs additional costs for LV fault location, because of the technical nature of its interconnected networks. It assessed these additional costs by comparing the average fault location unit costs of SP Manweb and SPD. DNV GL agreed with SP Manweb’s assessment and recommended that the claim for an additional £1.8m be accepted.

SHEPD

A summary of DNV GL's findings follows.

Weather/climate

SHEPD claimed that the remoteness of their customers results in an increase of costs in restoring supplies. SHEPD needs to transfer additional manpower to the islands prior to forecast storm events to ensure that there are sufficient resources to deal with potential faults. On average there have been 2 events p.a. where staff has been deployed, but the event has not materialised, with a total estimated cost of £100k. DNV GL agreed that SHEPD incur additional costs due to its remote areas and severe weather patterns, and recommended that the estimate of £100k pa be accepted.

Travel

SHEPD claimed that travel times to remote locations increase the cost of their operations. Excessive travel times result in delays as well as in the need for additional overnight accommodation for staff. Furthermore diesel fuel is more expensive on the islands than on the mainland, despite the 5p/litre island fuel subsidy, and long travel distances increases the amount of fuel bought. In total they have estimated increased costs of £250k pa due to these factors. DNV GL agreed that additional costs will be incurred due high fuel costs and long travel distances, but thought that SHEPD had not provided sufficient evidence to quantify the claim. They recommended that the allowance should be reduced to £210k pa.

SHEPD claimed that specialist staff often visits island locations to perform work that local staff cannot do. Furthermore, owing to the fragmented nature of the west and north coast with many islands, overnight accommodation is frequently required both for routine and fault work. Overnight stay is often required even for a short duration task on the island. SHEPD has assessed the cost for these factors at £135k pa. DNV GL agreed with SHEPD's claim for additional costs, and recommended that the claim be accepted.

SHEPD retains the services of a number of helicopter companies which allow their remote networks to be assessed from the air following a storm, to identify points of damage. The forecasted cost for helicopter use in 2013/14 was £120k pa.

DNV GL agreed that retaining helicopters in order to allow assessment of the networks is not normal practice within UK DNO's and that is a justified regional cost due to the remoteness of their network in northern Scotland. DNV GL disagreed with SHEPD's assessment of the costs and recommended a reduction from £120k to £80k pa, based on their own assessment of the frequency that helicopter services would be required.

Remote depots – property costs

SHEPD claimed that they incur higher property related costs as there are an increased number of depots required to support the network and customers.   On a per customer basis, there is 1 depot per 190,000 customers in SHEPD's area versus 1 depot per 320,000 customers in SEPD's area and they have calculated the additional cost of maintaining and running the depots in SHEPD's area to be £130k per annum. DNV GL considered that SHEPD provided reasonable justification for higher property related costs but had not provided sufficient evidence to support the quantified amount. DNV GL recommended that the allowance be reduced from £130k to £65k pa.

Depot staff

SHEPD claimed that they incur additional staff costs compared with other DNOs due to the remote location, geography and terrain of their network. They used a number of comparators to assess this cost, using SEPD as being representative of a typical DNO and as a result they have estimated additional costs of £2.76m pa, based on the need for 71 additional staff. DNV GL considered that SHEPD had conducted detailed analysis to estimate the impact of increased staff numbers that are required due to the nature of the area they cover, and recommended that the claim be allowed.

Private mobile radio system

Where geographically available SHEPD operational staff use GSM Mobile phones for day to day use but it also operates and maintains its own Private Mobile Radio (PMR) network to ensure safe operation during periods of severe weather and in remote locations. The PMR network was replaced in 2013 and has a significant level of resilience to power failures with 24 hour battery backup and also diesel generation with 7 days running stock maintained at all sites. SHEPD claims that the cost incurred annually for the ongoing maintenance and operation of the PMR system is £1.35m. DNV GL accepted the reasons for using both GSM and PMR but considered that these technologies are also used by other DNOs (although probably to a lesser extent). Accordingly, DNV GL recommended that the allowance be reduced to £650k pa.

Fixed diesel generation

SHEPD claimed that the operating costs associated with fixed diesel generation to ensure security of supply on the islands are additional costs that other DNOs do not incur. The fuel costs for these fixed diesel power stations have been increasing over the last number of years as diesel costs increase and the cost of operating and maintaining them was estimated as between £1.4m and £1.8m pa over the last 3 years. SHEPD claimed that the total annual cost associated with fixed diesel generation is £5.2m. DNV GL agreed that SHEPD ensures security of the supply on the (Western Isles, Orkney, Argyll and West Highland) islands with the help of diesel generators, and that without significant reinforcement it is impossible to avoid operation of these units. DNV GL recommended that the allowance be reduced to £4.2m pa, since this is in line with actual recent costs.

Subsea cables

SHEPD indicated that an extensive 33kV and 11kV subsea cable network is required to take power to the different islands and also to cross sea lochs.

SSE in response to Ofgem's slow track draft decision provided data to back-up their unit cost for marine cable replacement. DNV GL has reviewed this and is happy that £373k/km represents value for money.

In reaching this view, DNV GL has considered a number of assumptions that impact on costs including carrying out a programme of four to five cable replacements during the summer period of each year to reduce the need for mobilisation and demobilisation. However, in all reasonable scenarios considered SSE's £373k/km proved to be good value.

DNV GL view: SHEPD states that the average lifetime is between 18 to 24 years for submarine power cables. DNV GL accepts that there are certain external factors which are reducing the lifetime of the cables. Based on SSE's composite risk analysis 100% of the volume of asset replacement appears justified based on the composite risk analysis. However, there is a question over the cost benefit to the consumer of SSE’s move from a reactive approach to cable replacement where they respond to cable faults to drive asset replacement to the proactive approach they now wish to adopt based on condition assessment and composite health and criticality assessment. SSE has provided a CBA paper to demonstrate that it is beneficial to the consumer in the long run to move to proactive condition based asset management for their marine cable fleet. DNV GL has reviewed the CBA basis, assumptions and basic costs, however, we were unable to carry out any sensitivity analysis.

DNV GL conclude that subject to the request to rerun the CBA with a baseline model maximum per annum fault rate in-line with SSE’s statistics for the worst case year that the CBA demonstrates a long term benefit to the consumer of SSE’s move to a pro-active cable replacement programme and that the ED1 cable replacement volume appears reasonable based on the information presented.

NORTHERN POWER GRID

NPg submitted a claim for a company specific adjustment for regional factor adjustment associated with high concentration of 66kV and 20kV network voltages and here is the quick summary of the DNV GL comments.

66kV and 20kV equipment unit costs

NPg claims that 20kV and 66kV assets are significantly more expensive than 11/33kV assets, and the higher voltages are no longer needed to serve customer requirements. DNV GL agrees with NPg that 20kV and 66kV assets are significantly more expensive in comparison with 33kV and 11kV assets but this cannot be observed in isolation. At the time of network development adopted solution was selected as a least cost option for the customers (as indicated by NPg) and 66kV and 20kV assets in general do have a higher capacity when compared with 33kV and 11kV. In addition higher voltages carry number of advantages which are not captured in NPg submission eg size of the conductors is reduced (Cross section of the conductors reduce as current required to carry reduces), losses reduces results in better efficiency, due to low current voltage drop will be less so voltage regulation improves etc. Multiplying the marginal cost of 66kV equipment as opposed to 33kV equipment by the volume of 66kV asset replacement to calculate company specific adjustment in our view cannot be used as a proxy to calculate unit cost adjustment. Based on above DNV GL find there is an insufficient evidence to support NPg claim.

Network Architecture

NPg claims that 66kV is more complex than typical 33kV network and therefore it require greater number of circuit breakers. In order to calculate regional adjustment they are multiplying the number of CB proposed for replacement in ED1 which are at 66/11 and 66/20kV substations with Unit cost. In our view there is no real comparison with traditional DNO network and there is an insufficient evidence to support NPg claim.

Civil Works

NPg claim that due to the increased footprint of 66kV assets they are exposed to greater volume and unit cost. While we acknowledge that 66kV and 20kV civil works in general are more expensive when compared with 33kV and 11kV , NPg did not provide suitable justification to support their claim that 20% of disallowance from Ofgem modelling is due to the 66kv sites being renewed. NPg proposal for company specific volume adjustment associated with civil works is based on Ofgem benchmark cost. Similar to unit cost argument above, we find NPg justification not adequate and we cannot appraise it.