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Electricity Distribution Cost Review 2005-2006 January 2007

Document type: Annual Report

Ref: 18/07

Date of publication: 31 January 2007

Target audience: This document maybe of particular interest to electricity distribution network operators, investors, analysts, consumer groups and individual consumers.

Overview:

This report sets out operating cost and capital expenditure data for the 14 electricity distribution network operators (DNO) for the year ended 31 March 2006. It also shows Ofgem's current view of the Regulatory Asset Value (RAV) for each DNO as at 31 March 2006. The RAV will be finalised at the next price review.

This is the second annual report on DNO costs based on the cost reporting process developed during DPCR4.

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Context

All DNOs are required to report annually to Ofgem on the costs they incur in operating, maintaining and improving their distribution systems. Over time this information will show the trend of expenditure on each distribution system and inform the next price control review, DPCR5.

Ofgem is committed to publishing an annual report on cost data. While this report is the second of its kind, it is the first during the electricity distribution price control period from 1 April 2005 to 31 March 2010 (DPCR4).

The aim of the report is to present the key information on the DNOs' operating and capital costs in a meaningful and user friendly format.

Associated Documents

- Electricity Distribution Cost Review 2004-2005 (ref 263/05) - note this document sets out in its Appendices 1 and 2 the Price Control allowances for DPCR4
- Electricity Distribution Price Control Review Price control cost reporting rules: Instructions and Guidance (version 2.1) March 2006
- 2005/06 Electricity Distribution Quality of Service Report (ref 204/06)
- Electricity Distribution Price Control Review Final Proposals November 2004 (ref 265/04)
- DNO regulatory accounts 2005/06

These documents or links to them may be found on the Ofgem website (www.ofgem.gov.uk).

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Summary

One of the key lessons arising from the last electricity distribution price control review (DPCR4) was the importance of capturing historical data consistently on an annual basis. We have therefore committed to annual cost reporting. The process is designed to gain understanding of the costs and underlying policies of the electricity distribution network operators (DNOs). The work enables comparison of actual expenditure to the price control allowances set at DPCR4 and aims to inform the next price control (DPCR5).

By reviewing costs on an annual basis as DPCR4 progresses and setting indicative regulatory asset values, Ofgem is laying a solid foundation on which to build knowledge and develop policies for DPCR5. The reviews should reduce the amount of work required examining these areas at DPCR5 and mitigate one of the problems identified at DPCR4, that of reported historic data consistency.

The basis for the reporting of costs is set out in the Electricity Distribution Price Control Review Cost Reporting Rules: Instructions and Guidance (version 2.1) March 2006. These rules were developed following the last price control to provide a robust and coherent framework for cost reporting in the format of a Regulatory Reporting Pack (RRP). It comprises a formatted Excel workbook, a commentary on annual expenditure and comparison with the prior year.

Total industry operating costs in 2005/06 have remained consistent at around £700m. This masks variations across individual DNOs. In total it was 5% above the price control allowances.

Capital expenditure has increased by 4% over 2004/05 levels but this is 20% below allowances for 2005/06. DNOs forecast that capital expenditure will be 5% below the total allowances for the full five years of DPCR4. The current shortfall arises in part from the time taken to ramp up resources, DNO's assure us that resources are now substantially in place to deliver spend in future years in accordance with the allowances.

Total pension costs are 42% higher than allowances as three DNOs have made substantial lump-sum payments to repair pension fund deficiencies.

1. Overview of the process

Introduction

1.1. In April 2005, Ofgem first published Price Control Review Reporting Rules (the rules) setting out how DNOs should report cost information. These rules were revised to incorporate the experience and lessons learnt from the 2004/05 review, streamlining the data requests by combining cost pools for similar activities with relatively low costs and removing or modifying data points that were not useful. In addition working with industry assistance the definitions were tightened to alleviate interpretational and boundary issues. The rules for the 2005/06 RRP were published in March 2006 and are available on the Ofgem website (see Associated Documents above). It should be noted that the data in this report is extracted from the DNOs' submissions which have not been audited, although total costs are reconciled to the DNO's audited regulatory accounts.

Objectives

1.2. The rules provide a framework for the DNOs to report accurate and consistent information to Ofgem, using the RRP and by submitting a formatted commentary document.

1.3. The objectives of the rules are to:

- ensure the RAV is rolled forward according to the DPCR4 Final Proposals;
- improve robustness and consistency of cost data reported to Ofgem;
- reduce the burden on DNOs to provide financial and other information at the time of a price control review; and
- avoid varying interpretations of definitions and reporting requirements.

Comparability

1.4. Ofgem recognises that whilst the data submitted by the DNOs under the rules should be consistent with the definitions provided, there are a number of reasons why reported costs may vary across DNOs including:

- structure of the DNO's group, including related party service providers, recharging of corporate services and inter-DNO charging;
- management policies, both historic and current;
- legacy issues including pre-privatisation and previous ownership decisions; and
- different network sizes, structures and operating environments

1.5. Comparability adjustments have not been applied to the data in this report and Ofgem stresses the data should not be used for comparison purposes without taking the above-mentioned factors into consideration.

Processes for 2005/06

1.6. The process was similar to that for 2004/05. Following receipt of submissions in July 2006, Ofgem reviewed and analysed the data in depth to assess its compliance with the rules, its robustness and its consistency, prior to visiting each of the DNOs.

1.7. The visits were structured so that DNOs were provided with a detailed agenda setting out Ofgem's objectives to enable the companies to be adequately prepared and to utilise the available time efficiently. Discussions during the visits allowed Ofgem to obtain an understanding of each DNO's business structure and practices and the ways in which these impacted on costs during 2005/06. Expenditure against DPCR4 allowances was also reviewed, with particular regard to performance against five-year capex plans. The meetings have all been constructive and considered beneficial by both the DNOs and Ofgem.

1.8. DNOs have generally, with exceptions, adapted their internal reporting systems such that most cost data for 2005/06 has come directly from accounting systems, reducing the need for management estimation of cost breakdowns. However, in some cases, there is scope for further improvement in this regard.

1.9. All the DNOs committed significant resources to the process, including input from senior staff, and Ofgem acknowledges the work required in the preparation of data and information in accordance with the rules for this second year. Overall, the quality of data reported for 2005/06 reflected a significant improvement in accuracy and comparability over data reported for 2004/05.

1.10. The review and visit process identified requirements for DNOs to revise, to varying degrees, their original submissions. The resubmissions resolved a number of issues and minor inconsistencies in treatment. One particular issue affecting some DNOs was the requirement to report the full costs (and customer contributions) relating to connections activities in their licensed areas, including those carried out by related parties. This follows the revised definition of a distribution business which came into effect from 1 April 2005. Work is continuing on analysis of the data to address remaining inconsistencies. Ofgem's discussions with DNOs suggest that residual inconsistencies will mainly relate to the factors in paragraph 1.4 above and to two key boundary issues: fault repair/asset replacement and direct/indirect labour. Ofgem will be asking the DNOs to carry out further work in early 2007 to gather information on these cost boundaries.

1.11. Ofgem recognises that all DNOs learned from completion of the packs in 2004/05 and subsequent discussions. DNOs have submitted more robust data this year. Notwithstanding the scope of improvements throughout the sector, some companies' initial submissions in 2005/06 had specific weaknesses, and there is room for further improvement to reach a higher standard in 2006/07. As noted

above, some DNOs initially provided insufficient visibility of the costs of related parties providing connections and, in addition, of captive insurance providers. A high level of importance is attached to the cost reporting process in DPCR4 (see paragraphs 7.86 and 7.87 of the Final Proposals[1] for example) and Ofgem is confident of continuing improvements in data quality in future years. Ofgem intends to make only minor changes to the rules for 2006/07 to resolve difficulties identified this year and to encourage DNOs (where appropriate and feasible) to develop their systems to collect data in the format required.

[1] Electricity Distribution Price Control Review Final Proposals November 2004 (ref 265/04)

2. Industry performance

Chapter Summary

This section sets out the overall performance of the electricity distribution industry and shows total costs activity analysis, operating, capital and pension expenditure across the DNOs, indicative Regulatory Asset Values and year-end regulatory gearing figures.

Total Costs Activity Analysis

2.1. Table 2.1 below shows a summary form of the activity breakdown of costs for year ended 31 March 2006 on the basis set out in the rules for reporting expenditure. A full analysis of DNOs' expenditure by activity, reconciled to the expenditure in their regulatory accounts can be found on Ofgem's website.

2.2. This is the first time that such disaggregated data has been published. Table 2.1 shows total typical cash costs on an activity basis (i.e. before indirect costs are capitalised by the DNO). Typical costs (on a cash and normal level of trading accruals basis) include the normal level of employer pension contributions (but not pension deficit payments) and exclude rates, licence fees, transmission exit charges and depreciation). Atypical cash costs and pension deficiency payments are shown in total.

2.3. Atypical events are specific events or incidents that are not expected to recur regularly under normal circumstances due either to their size, nature or severity, including for example all severe weather events that meet the relevant exceptionality requirement defined in annex B of special condition C2 of the electricity distribution licence. They also include business restructuring costs. With certain exceptions, e.g. early retirement deficit costs, atypical costs are allowable in computing additions to RAV.

2.4. The individual activities in Table 2.1 above are defined in the rules. The costs are shown before allocation of indirect costs to direct opex and capex (net of customer contributions). All customer contributions for new connections are included (as negative) under Load Related New Connections & Reinforcement expenditure. It should be noted that in their own financial statements companies allocate indirect costs to direct activities based on their own internal reporting and accounting criteria.

Table 2.1: Activity Costs before allocation to direct opex and capex less customer contributions

	Cash typical costs (note 4)										
	Direct activities					Indirect activities					
y/e 31 March 2006	Load related new connections & reinforcem't (net of contributions)	Non-load non-fault new & replacement assets (net of contributions)	Non-operational capex	Total Faults	Inspections, Maintenance & Tree Cutting	Engineering indirects (note 1)	Network indirects (note 2)	Business Support (note 3)	Atypical cash costs (note 4)	Pension deficit payments (note 5)	**Total Distribution Business Cash Costs**
£m (05/06 prices)											
CN West	22	52	2	26	8	17	17	24	4	68	**240**
CN East	17	35	2	27	14	22	19	22	6	46	**210**
UU	12	36	11	18	7	24	14	30	4	52	**208**
CE NEDL	6	34	4	13	8	13	14	17	2	18	**129**
CE YEDL	13	56	3	17	10	17	14	21	1	5	**157**
WPD S Wales	6	17	2	8	10	10	12	15	2	4	**86**
WPD S West	9	30	10	14	12	15	15	18	2	7	**132**
EDFE LPN	7	50	3	18	10	16	13	22	2	15	**156**
EDFE SPN	8	50	4	21	17	14	17	22	2	16	**171**
EDFE EPN	12	55	8	27	22	21	25	32	6	4	**212**
SP Distribution	3	35	7	14	11	22	25	24	0	0	**141**
SP Manweb	13	39	5	15	14	21	25	26	0	13	**171**
SSE Hydro	(2)	21	0	7	7	11	10	20	1	0	**75**
SSE Southern	15	46	0	24	12	21	19	26	0	24	**187**
Total	**141**	**556**	**61**	**249**	**162**	**244**	**239**	**319**	**32**	**272**	**2275**

Notes

1 includes activities of Network Policy, Network Design and Engineering Management & Clerical Support

2 includes activities of Wayleave administration, Control Centre, System Mapping, Call Centre, Stores & Procurement, Vehicles & Transport, Health & Safety & Operational Training

3 includes activities of IT & Telecoms, Property management, HR & Non-operational Training, Finance & Regulation, CEO etc

4 All typical & atypical cash costs include normal pension costs, except for UU which exclude normal pensions costs

5 Pension deficit payments are shown separately. For UU and CN this includes lump sum payments. The amounts shown are before application of the disallowance for ERDCs and non-distribution activities - see Table 2.3

Operating Costs

2.5. Table 2.2 below shows operating costs (opex) for 2004/05 and 2005/06. It should be noted that the DPCR3 price control treated indirect costs, fault repair costs and pensions differently in respect of additions to the RAV. These opex figures include atypical items, e.g. severe weather events (which decreased to £4m from £17m in 2004/05), restructuring and reorganisation costs. United Utilities' reported opex is lower than actual expenditure by the proceeds from the disposal of non-operational assets, which in accordance with the Final Proposals is treated as opex. In addition opex has been reduced by the adjustment for the difference between forecast and actual excluded services revenue (for further details see Appendix 1 of the Final Proposals) as shown in the table. The table also shows the DPCR4 opex allowances and the over/(under) spend to allowances.

Table 2.2: Operating costs (excluding all pensions, rates, licence fee & depreciation)

	Actual	Actual Gross Opex	Disposals & excluded service adjustment	Actual Net Opex	DPCR4 allowance	Over / (under) spend to allowance
year ended 31 March	2005	2006	2006	2006	2006	
£m (05/06 prices)						
CN West	56	57	(1)	56	54	2
CN East	57	65	(1)	64	57	7
UU	66	58	(9)	49	52	(3)
CE NEDL	35	37	-	37	37	-
CE YEDL	46	44	-	44	44	-
WPD S Wales	28	31	-	31	34	(3)
WPD S West	40	47	-	47	41	6
EDFE LPN	50	48	(5)	43	45	(2)
EDFE SPN	59	56	(3)	53	47	6
EDFE EPN	77	81	(5)	76	70	6
SP Distribution	48	55	(2)	53	48	5
SP Manweb	54	56	(2)	54	39	15
SSE Hydro	27	30	-	30	33	(3)
SSE Southern	53	56	-	56	59	(3)
Total	**696**	**721**	**(28)**	**693**	**660**	**33**

Notes:

Actual net opex is presented on the basis for computing opex compared to the allowances set out in the Final Proposals

Actual gross opex is computed as for net opex and is grossed up to show the impact of including the proceeds from the disposal of non-operational assets and the adjustment for the difference between forecast and actual excluded services revenue (for further details see Appendix 1 of the Final Proposals) exclusive of the 23.5% element treated as capex

2.6. In 2005/06 the level of operating costs (excluding all pensions, rates, licence fees and depreciation but including atypicals) across the industry is 5% higher than the allowances for the year. Table 2.2 above shows how companies have moved from their 2004/05 expenditure levels.

2.7. There has been only limited restructuring cost incurred in the industry in 2005/06. Central Networks have largely completed the integration of the former Midlands and East Midlands businesses resulting in an improvement to the quality of their data. Restructuring costs account for just over 1% of total typical and atypical operating costs compared to 4% in 2004/05.

2.8. Insurance costs (which are reported within the Finance and Regulation Activity and grouped with Business Support Costs in Table 2.1 above) vary between DNOs, depending on attitudes to risk and corporate policy. The majority of companies have discontinued overhead line cover (storm cover) which has become prohibitively expensive.

Inspections and Maintenance

2.9. For some asset categories, maintenance frequencies and work to be undertaken have been determined by Reliability Centred Maintenance (RCM) analysis. Maintenance intervals are therefore a combination of time based and condition based assessment. This is more sophisticated than traditional inspection/maintenance regimes which tended to be almost solely based on periodic intervals. The requirement for invasive inspections has also been significantly reduced. For overhead lines the use of helicopter and high definition photographic surveying in place of line walking inspections has increased.

2.10. Coastal corrosion problems are being managed by installing indoor kit and by increased inspection and maintenance. There continue to be particular maintenance issues with certain items installed on networks, such as particular kinds of insulating oil and battery types prone to premature failure. Some DNOs have only recently completed the integration of inspection and maintenance systems where they have more than one licensed area and expect this to lead to future efficiencies. Discussions during the review visits have assisted in defining the maintenance/replacement boundary with regard to network assets.

Dealing with Faults

2.11. To varying degrees DNOs are continuing to invest in automation to improve network performance. Some DNOs are making further investment in network control systems for automatic sequential switching following a fault to improve their interruption performance.

2.12. There is increased spending on tree cutting both to comply with the Electricity Safety, Quality and Continuity Regulations (ESQCR) and to reduce tree related faults (one of the main causes of faults in severe weather). There were fewer exceptional weather events reported by DNOs and from a cost perspective these were insignificant, accounting for 0.1% of total operating costs (compared to 2% in 2004/05).

2.13. During the review it became apparent that some DNOs had continued to report labour and fault costs on the same basis as they had in DPCR3 and which was not in accordance with the rules. As a consequence we are undertaking further work in this area (see 1.10 above) and when this work is concluded there may be revisions to the amounts provisionally reported in all Tables.

Non-Operational new and replacement assets

2.14. For regulatory cost reporting purposes, Non-Operational New and Replacement Assets includes expenditure on capital items for use of the distribution business which are not distribution system assets such as office buildings, computer hardware, vehicles and small tools and equipment.

2.15. Most companies have ongoing programmes to replace information systems. Companies generally aim to avoid peaks and troughs of expenditure, although some DNOs are planning comprehensive IT replacement projects. Several have invested in developments of the SAP platform and other proprietary software and hardware systems.

2.16. Some DNOs own their own vehicle fleets whereas others lease them. Specialist vehicles tend to be purchased in all cases.

Pensions

Table 2.3: Pensions (note columns may not cast due to roundings)

£m (2005/06)	Normal Employer Pension contributions	Allowable Pension Deficit payments	Total allowable pension payments	Pension Allowance
CN West	6	44	49	18
CN East	6	30	36	14
UU (see note)	42	40	83	17
CE NEDL	5	13	18	19
CE YEDL	6	5	10	11
WPD S Wales	4	3	7	11
WPD S West	7	4	10	16
EDFE LPN	4	17	22	24
EDFE SPN	5	13	17	22
EDFE EPN	8	4	12	13
SP Distribution	5	0	5	5
SP Manweb	6	11	16	17
SSE Hydro	3	0	3	4
SSE Southern	6	24	30	33
TOTAL	**111**	**207**	**318**	**224**

Note: UU's allowable pension payments include a 5 year lump sum advance payment of normal and deficit contributions.

2.17. This year has seen the first payments to pension schemes by several DNOs to make up deficits. United Utilities made a substantial one-off pension payment on 31 March 2005 which comprised not only a deficit repair payment but an advance payment for five years' worth of normal contributions. This has been treated as paid on 1 April 2005 for regulatory purposes by prior agreement with Ofgem. Other companies making significant deficit payments were Central Networks, where the parent E.ON made a payment on the merger of four separate pension schemes, SSE Southern and EDFE LPN and EDFE SPN. Ten companies increased the level of normal

employer contribution rates following their last actuarial valuations and funding recommendations.

2.18. All of the DNOs are taking measures to manage their exposure to the risk based element of the levy to which they will be subject under the Pension Protection Fund scheme.

Capital Expenditure

2.19. Table 2.4 below shows total capital expenditure (excluding all pension costs) on new and replacement assets for 2005/06 compared to 2004/05 and the average price control allowance for DPCR4 for each company and the percentage under/ (over) spend to the allowance. Actual costs are reported on the basis set out in Appendix 1 to the Final Proposals and include the impact of the reduction for the amount allowed into capex referred to in Table 2.2.

Table 2.4: Capital Expenditure (excluding all pension costs)

	Actual	Actual	Average allowance	Percentage under/(over) spend
y/e 31 March	2005	2006	2006 - 2010	2006
£m (05/06 prices)				
CN West	82	107	120	11%
CN East	81	86	119	28%
UU	103	84	112	25%
CE NEDL	52	60	68	11%
CE YEDL	90	94	90	(4)%
WPD S Wales	48	44	48	7%
WPD S West	68	68	69	2%
EDFE LPN	60	85	107	21%
EDFE SPN	84	90	115	22%
EDFE EPN	107	110	167	34%
SP Distribution	70	71	90	21%
SP Manweb	91	87	97	11%
SSE Hydro	38	38	51	26%
SSE Southern	97	94	135	31%
Total	**1,071**	**1,117**	**1,388**	**20%**

2.20. While the total capital expenditure (capex)[2] for the industry was 20% below the allowances, there were significant variances between actual costs and allowance

[2] Capex is calculated in accordance with Appendix 1 to the Final Proposals and includes Load-related new connections and reinforcement and Non-Load non-fault new and replacement

in the companies, notably the under-expenditure relative to allowances in the EDF Energy and CN East and the 4% over-expenditure relative to allowance at CE YEDL. Overall there is a 4% increase in capex over 2004/05. This factor accounts for some of the under-expenditure at both of SSE's and SP's DNOs and at United Utilities because of the treatment of new connections activities undertaken by affiliates. The reasons given by the DNOs for underspend against allowances are set out below.

Ability of companies to deliver capital investment plans

2.21. The majority of companies forecast significant increases in capex in DPCR4 compared to DPCR3. Factors affecting the companies' ability to deliver the increased capital investment plans include:

- shortage of skilled labour (internal and external);
- restricted availability of plant from manufacturers with long production and delivery times;
- constraints on planned power outages;
- competing demand for resources from other sectors, including electricity transmission; and
- obtaining planning consents, especially in areas of natural beauty.

2.22. The procurement of plant, equipment, materials and external services is often managed by DNOs on the basis of framework contracts. These contracts tend to be for a two or three year period with one or two year extension options. Contractors have responded to increased volumes of work and increased their own staff numbers accordingly.

2.23. DNOs are increasing internal resources by recruiting staff at all levels including graduates and apprentices. In some cases, they are planning to take on 'mature workers' often with a technical background. All of the DNOs, however, are presently experiencing strong local competition for skilled labour which is putting upward pressure on costs. Wage levels for skilled staff have generally been rising ahead of RPI. The majority of DNOs should be able to overcome the difficulties, and some have already reached the sustainable level of resourcing required to complete their capital expenditure programmes.

2.24. Network access constraints (planned outages) are becoming more significant in delivering the planned investment. Outage programmes are generally prepared up to two years ahead with the involvement of control staff.

2.25. Recent increases in copper and steel prices have also impacted capital investment plans. These are driving up unit costs and it now appears that efficiency

assets, both net of customer contributions, and a proportion of other direct and indirect activity costs (see Table 2.1) excluding all pension costs

gains may be more than off-set by increased unit costs. DNOs are reporting that primary transformers and cable prices have increased significantly. In one instance, a DNO now estimates that a major primary reinforcement scheme will double in cost. Some companies have said that capital expenditure schemes may be deferred until the next regulatory period and that asset replacement levels will be lower than forecast. Other companies have indicated that some revision to their five year capital plans will be required because of the increase in unit costs.

2.26. Theft of copper from DNOs' sites is reported to be on the increase across the country and companies are spending a significant amount of time and resources on site security.

Degree of churn of capex schemes

2.27. For a majority of DNOs there is a significant degree of scheme churn (i.e. different schemes from those set out in forecasts prepared during the last price review) even at this early stage in the regulatory period. In some cases system reinforcement and asset replacement schemes have been deferred until after the end of DPCR5 whilst new schemes for the current period have been introduced. Scheme phasing, and forecast costs have also varied significantly from earlier predictions.

2.28. There has been a swing of expenditure from non-load related expenditure (NLRE) work programmes (asset replacement and refurbishment) to load related expenditure (LRE) schemes (to meet increased demand) in several companies during the year. This may have been driven by strategic reinforcement to give additional network flexibility and/or by an increase in localised reinforcement costs under new connection charging arrangements which only require new demand customers to pay a contribution for reinforcement to a shallow level at time of connection. Several companies are reporting hot spots of load growth with increased domestic connections; DNOs continue to be the dominant connections providers in their respective licensed areas. In some instances there has been an increase in un-metered connections, mainly street lighting.

Distributed Generation

2.29. The connection of 'relevant' distributed generation (DG) to distribution networks under the new incentive mechanisms (from 1 April 2005) has been lower than expected. Most DG due to come on line (e.g. offshore/onshore wind farms) are remote from load centres thereby increasing connection costs. There was little activity in 2005/06 regarding small scale schemes such as micro-generation and small scale CHP (combined heat and power). Some DG connections are still being made under contractual arrangements put in place before 1 April 2005 ('non relevant' DG) and the number of 'relevant' DG connections is expected to increase in future.

2.30. There is still an expectation that small scale generation schemes could appear in substantial numbers in future and their impact could change the nature and functionality of the network. The industry is considering the distribution network

requirements up to 20 years in the future to accommodate the expected increase in the amount of generation directly connected to distribution networks.

Asset risk management, asset condition data and PAS55

2.31. The majority of companies have adopted or are developing 'Health Indices' to enable asset condition related risks to be quantified and deterioration rates to be monitored and forecast.

2.32. The initial work undertaken has identified those aspects of asset condition affecting reliability and asset life. When identified, asset condition assessment criteria are established and embedded in data collection systems to populate during asset inspections. Several companies appear to be well advanced in this but since intrusive asset condition inspections seldom take place at less than 12 year cycles for the majority of assets, it will be some time before asset condition databases are fully populated. Nevertheless at primary voltage levels, some inspections take place on a shorter inspection cycle and more condition information should be available for these.

2.33. Although companies propose to use analytical techniques based on health indices for the preparation of their asset replacement expenditure for DPCR5 and beyond, they accept that only a limited sample of information will be available. Many of the assets installed on distribution networks have exceeded their 'design life', but the RCM programmes now used by most DNOs mean that replacement decisions can be taken in a timely but efficient way.

2.34. All companies intend to seek PAS55 certification in accordance with Ofgem's proposed timetable, i.e. April 2008.

Quality of Service Investments and Initiatives

2.35. DNOs plan to continue investing in network automation/remote control to improve their quality of service performance and to obtain benefits from the 'interruption incentive scheme'. Some companies are investing in additional protection schemes to minimize the consequence of faults and are incorporating automatic sequential switching programmes within their network control systems. There is some variance in the approach taken by DNOs with regard to faults which arise 'out of hours'. In some cases, DNOs take the decision on how quickly to respond on a cost/benefit basis, based on labour costs versus incentive payments.

2.36. Following previous investment on high voltage (HV) assets and the systems referred to above, more companies are focusing on LV network performance as this is now the cause of a higher percentage of CMLs ('customer minutes lost') than previously. DNOs are pursuing a number of initiatives to improve their overall fault performance. Measures such as dedicated fault teams for repair restoration within defined areas; cable 'sniffers' for fault location, live line working and fault passage indicators with GPS technology are being introduced. At least one DNO group is

cutting investment in Quality of Service because it sees limited future gains since it is at the top of its performance criteria already.

2.37. For further detail on DNOs' quality of service performance, please see Ofgem's 'Quality of Service report November 2006' which is available on Ofgem's website.

Additions to RAV

2.38. Ofgem's current view of the additions to the Regulatory Asset Value is shown in Table 2.5 below. In calculating the RAV rolled forward from 1 April 2005, Ofgem has applied the methodology set out in Appendix 1 of the Final Proposals.

2.39. In reviewing reported costs Ofgem has been particularly concerned to ensure:

- that key boundaries between activities whose costs enter RAV in different percentages have been respected (e.g. direct capex, direct and indirect opex);
- that only the time-sheeted labour costs of staff physically working on network assets have been included in direct costs;
- that costs and capital contributions associated with providing connections to the licensee's distribution system (including any contributions retained under the previous tariff support arrangements) have been fully included in the data for the distribution business, whether provided by the licensee or a related party (in accordance with the definitions in the licence);
- the correct treatment of transactions with related parties (e.g. captive insurers);
- that revenue earned by a related party fulfilling an obligation of the licensee and acting on behalf of the licensee does not count as external turnover in considering related party margins; and
- that treatment of excluded services costs and revenues has been consistent with the licence conditions and final proposals (which require a RAV adjustment for the difference between forecast and actual excluded services revenue).

2.40. Ofgem has rolled forward the RAV on the same basis for all licensees in accordance with the methodology set out in Appendix 1 of the Final Proposals. Adjustments to 2005/06 values may be necessary in light of the further work on fault repair/asset replacement and direct/indirect labour but are not expected to be large. Ofgem will be reluctant to re-open past RAV calculations but cannot rule this out, particularly if it becomes evident that the information provided by the licensee concerned was inaccurate.

RAV roll forward

2.41. Table 2.5 below shows Ofgem's current view of the RAV roll forward for the year ended 31 March 2006. The provisional RAV figures in the table have been discussed with the DNOs concerned, although in several cases the DNO has not agreed the figure shown. The RAV will be finalised at the next price review.

Table 2.5 RAV roll forward - Ofgem provisional view

	Balance b/f 1 April 2005	Memo: Additions per Final Proposals	Additions Actual	Depreciation	Balance as at 31 March 2006	Balance as at 31 March 2006 (see note)
	£m (2005/06)					£m(nominal)
CN West	1041	**132**	136	(78)	**1098**	**1113**
CN East	1029	**128**	107	(83)	**1052**	**1066**
UU	999	**122**	131	(74)	**1056**	**1070**
CE NEDL	643	**79**	71	(48)	**666**	**675**
CE YEDL	872	**97**	100	(73)	**898**	**910**
WPD S Wales	626	**54**	48	(50)	**624**	**633**
WPD S West	770	**79**	74	(55)	**788**	**799**
EDFE LPN	960	**122**	97	(73)	**984**	**997**
EDFE SPN	666	**129**	100	(49)	**717**	**727**
EDFE EPN	1185	**175**	117	(85)	**1217**	**1233**
SP Distribution	1364	**93**	74	(119)	**1319**	**1337**
SP Manweb	805	**107**	96	(57)	**844**	**856**
SSE Hydro	793	**54**	40	(55)	**778**	**788**
SSE Southern	1457	**155**	111	(107)	**1461**	**1481**
Total	13210	**1525**	1301	(1008)	**13503**	**13687**

Notes:

CE NEDL & CE YEDL opening RAV balances have been decreased by prior year adjustments of £2m & £1m respectively by agreement with them

The RAV balance at 31 March 2006 has been calculated using the average of the RPI for March & April 2006

Columns may not cast due to roundings

2.42. Across the industry, actual RAV additions are 15% lower (2004/05 - 8% lower) than the price control allowances. RAV additions are materially lower at EDF Energy's DNOs (circa 26%) and Scottish & Southern DNOs (28%) reflecting their capital investment activity but higher at United Utilities (by 7%) reflecting the impact of capitalising part of their additional pension payments.

2.43. A rolling capex incentive mechanism was included in the Final Proposals. This, in conjunction with a sliding scale mechanism (to accommodate a range of approaches between DNOs in relation to capital expenditure projections) will allow DNOs to keep (bear) a percentage of the value of their under (over) spend for a full period of five years. The industry is currently forecasting to underspend its allowances by approximately 5% over the DPCR4 period.

Gearing to RAV

2.44. Table 2.6 below shows each DNO's gearing (defined as net debt to RAV), which is Ofgem's primary measure of gearing for the 2005-10 price review.

Table 2.6: Gearing to RAV

	Net Debt	RAV	Gearing at 31 March	
	as at 31 March 2006 £m (nominal)		2006 %	2005 %
CN West	580	1,113	52%	46%
CN East	450	1,066	42%	26%
UU	500	1,070	47%	70%
CE NEDL	297	675	44%	42%
CE YEDL	425	910	47%	46%
WPD S Wales	205	633	32%	24%
WPD S West	149	799	19%	34%
EDFE LPN	544	997	55%	52%
EDFE SPN	522	727	72%	72%
EDFE EPN	760	1,233	62%	62%
SP Distribution	765	1,337	57%	58%
SP Manweb	430	856	50%	23%
SSE Hydro	375	788	48%	61%
SSE Southern	883	1,481	60%	62%
TOTAL	**6,884**	**13,687**	**50%**	**50%**

2.45. The gearing ratio used in the DPCR4 cost of capital was 57.5% compared to the overall industry weighted average gearing of 50% (2004/05 - 50%). DNOs' individual debt and gearing varies depending on the company's own financing structures within individual ownership groups. During the year, overall net debt has increased by £380m.

2.46. The table does not include guarantees provided by licensees for parent company debt:

- £1970m jointly by SP Distribution and by SP Manweb's immediate parent company (along with SP Transmission)
- £450m by SSE Hydro provided jointly with Scottish Hydro-Electric Transmission Limited

2.47. The debt shown in Table 2.6 above does not include the impact of derivatives hedging of either currency or interest rates at the year end.

3. Ongoing work

3.1. As noted above, 2005/06 was the second year for which the DNOs have submitted information under the Cost Reporting Rules.

3.2. Work is underway to refine the rules where necessary to improve further the consistency of information reported by all DNOs and its potential usefulness for the next price review. This is an evolutionary process; Ofgem will continue to work with the DNOs to strengthen and improve cost reporting. For next year, our intention is to make only minor revisions to the regulatory reporting pack and rules to remove unnecessary data points and clarify definitions. In addition, following agreement from the DNOs two new tables are being introduced covering network risk and one analysing year-on-year movements. Ofgem has begun to consider and examine alternative ways of using the reported data for cost assessment for DPCR5.

3.3. We intend to issue the Rules for 2006/07 in March 2007.

3.4. Ofgem's next electricity distribution cost report will cover the year ended 31 March 2007, which is the second year of the DPCR4 price control period. The current intention is to publish this in December 2007.

Appendices

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Appendix 1 - Response and Questions

Ofgem welcomes views on the type and format of information that users of this report would find useful.

Please send your comments to:

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Appendix 2 - Background on the 14 Electricity DNOs

Background

1.1. At privatisation, the Public Electricity Suppliers (PES) were responsible for both the distribution and supply of electricity, taking the place of the former regional electricity boards. With the introduction of competition in supply, it was important to ensure that all supply businesses, both new and old, had fair access to the distribution networks.

1.2. The Utilities Act 2000 introduced separate licences for distribution and supply, and required that these be held by separate legal entities.

Distribution

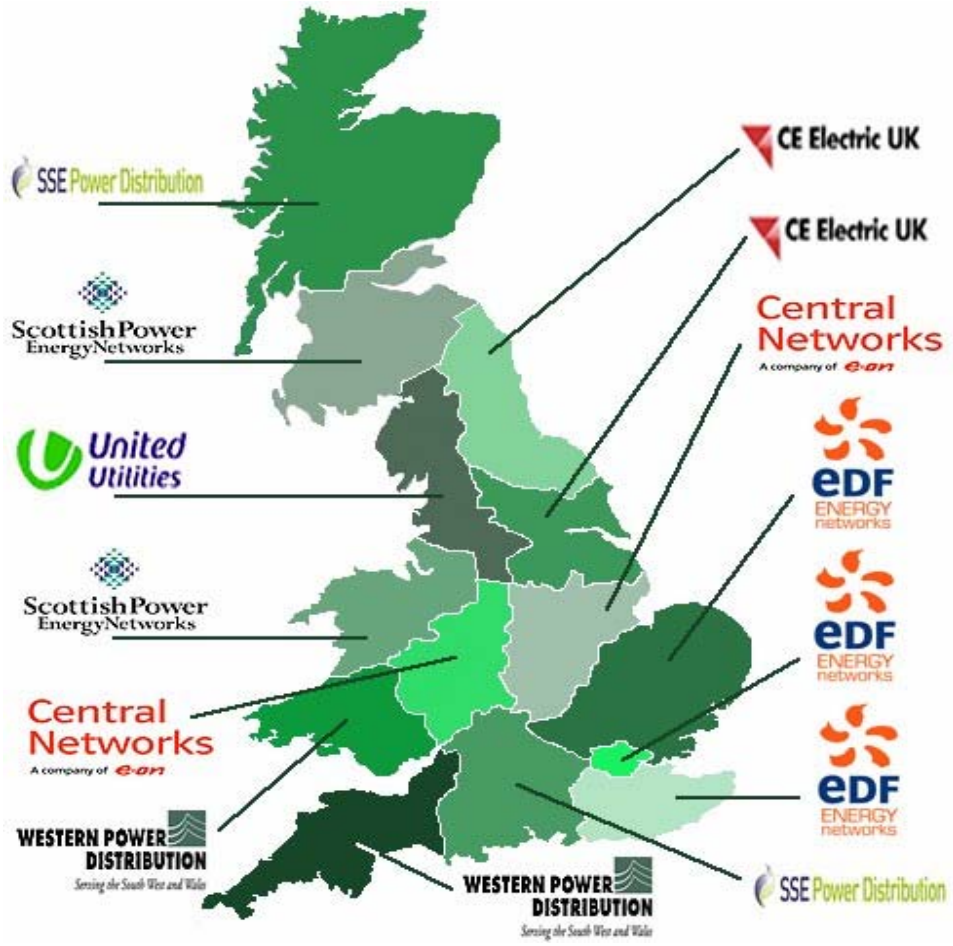
1.3. DNOs are responsible for local distribution of electricity along overhead wires and through underground cables. This includes responsibility for ensuring that customers have a reliable electricity supply. After a number of corporate acquisitions, the 14 distribution licenses were owned by seven separate companies (see Map) for the whole of the year ending 31 March.

How much does distribution cost the customer?

1.4. Electricity distribution charges account for around £3.5 billion annually and make up around 17 per cent of customers' electricity bills.

1.5. For a typical domestic electricity customer, based on consumption of 3300 kWh of electricity a year, the distribution element of their bill is approximately £60.

MAP OF GREAT BRITAIN SHOWING THE GEOGRAPHICAL AREAS OF THE 14 DISTRIBUTION NETWORK OPERATORS



Name in the report	Name on Map
CN West	Central Networks
CN East	Central Networks
UU	United Utilities
CE NEDL	CE Electric UK
CE YEDL	CE Electric UK
WPD S Wales	Western Power Distribution
WPD S West	Western Power Distribution
EDFE LPN	EDF Energy
EDFE SPN	EDF Energy
EDFE EPN	EDF Energy
SP Distribution	Scottish Power
SP Manweb	Scottish Power
SSE Hydro	Scottish & Southern Energy
SSE Southern	Scottish & Southern Energy

Appendix 3 - Network Statistics

Network statistics

	Total No of Customers	Length of circuit km		
		Overhead	Underground	Total
CN West	2,390,474	24,021	37,280	61,301
CN East	2,519,256	22,829	46,998	69,827
UU	2,306,432	13,004	42,930	55,933
CE NEDL	1,538,904	15,413	24,017	39,430
CE YEDL	2,210,799	13,709	37,757	51,467
WPD S Wales	1,092,326	18,291	16,177	34,468
WPD S West	1,501,406	28,485	20,630	49,115
EDFE LPN	2,193,057	47	35,432	35,479
EDFE SPN	2,209,828	12,714	37,591	50,305
EDFE EPN	3,437,289	34,635	58,932	93,567
SP Distribution	2,013,009	21,207	39,680	60,887
SP Manweb	1,500,704	21,518	26,225	47,743
SSE Hydro	700,930	31,189	14,105	45,294
SSE Southern	2,812,752	27,614	49,566	77,180
Great Britain	28,427,166	284,676	487,319	771,996

Note: The 132kV network in Scotland forms part of the Transmission system

Appendix 4 - The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[3]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[4].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[5]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[6]

[3] entitled "Gas Supply" and "Electricity Supply" respectively.
[4] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[5] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[6] The Authority may have regard to other descriptions of consumers.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed[7] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[8] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[7] or persons authorised by exemptions to carry on any activity.
[8] Council Regulation (EC) 1/2003

Appendix 5 - Glossary

Ofgem has produced a glossary of terms relating to Electricity Distribution Cost Review. These can be found in Appendix 2 of the Ofgem document:

- Electricity Distribution Price Control Review Price control cost reporting rules: Instructions and Guidance (version 2.1) March 2006

Appendix 6 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Does the report adequately reflect your data and that of the industry as a whole? If not, why not?
2. Did the report offer a clear explanation of and for the data provided? If not, how could this information have been better presented?
3. Do you have any comments about the overall tone and content of the report?
4. Was the report easy to read and understand, could it have been better written?
5. To what extent did the report's conclusions provide a balanced view?
6. Please add any further comments?

1.2. Please send your comments to:

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