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Electricity Distribution Cost Review 2006-2007

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Target audience: This document may be of particular interest to electricity distribution network operators, investors, analysts, consumer groups, individual consumers and other interested parties.

Overview:

This report sets out operating cost and capital expenditure data for the 14 electricity distribution network operators (DNOs) for the year ended 31 March 2007. It also shows Ofgem's current view of the Regulatory Asset Value (RAV) for each DNO as at 31 March 2007. The RAV will be finalised at the next price review.

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

Contact name and details: Bill McKenzie, Senior Manager, Cost Review

Tel: 020 7901 7220

Email: william.mckenzie@ofgem.gov.uk

Team: Financial Reporting, Electricity Distribution

Context

All electricity distribution network operators (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 electricity distribution price control review, DPCR5.

We are committed to publishing an annual report on cost data. While this report is the third of its kind, it is the second 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

The following documents may be found on our website:

http://www.ofgem.gov.uk/Networks/ElecDist/Pages/ElecDist.aspx

- Electricity Distribution Cost Review 2005-2006 (ref 18/07)
- Electricity Distribution Industry Activity Costs (ref 290/07a)
- 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 2.21) March 2007
- 2006/07 Electricity Distribution Quality of Service Report (ref 268/07)
- Electricity Distribution Price Control Review Final Proposals November 2004 (ref 265/04)
- Links to DNO regulatory accounts

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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, we have laid a solid foundation on which we have built our knowledge and on which policies will be developed for DPCR5. The reviews will reduce the amount of work required examining these areas at DPCR5 and mitigate the problem of reported historic data inconsistency.

The basis for the reporting of costs is set out in the Electricity Distribution Price Control Review Cost Reporting Rules: Instructions and Guidance (version 2.21) March 2007. 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). The pack comprises a formatted Excel workbook and a commentary on annual expenditure.

Total industry net operating costs in 2006/07 have remained consistent at around £730m. This masks variations across individual DNOs. In total operating costs were 9% above the price control allowances.

Capital expenditure has increased by 4% over 2005/06 levels but this is 16% below average allowances for DPCR4. DNOs forecast that capital expenditure will be 6% 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. DNOs assure us that resources are now substantially in place to deliver spend in future years in accordance with their investment plans.

Total pension costs are 10% higher than allowances as one DNO has made a substantial lump-sum payment to repair pension fund deficiencies compared to three doing so last year. Excluding this DNO, the other DNOs are making slightly lower than forecast deficit repair payments this year.

1. Overview of the process

Introduction

1.1. In April 2005, we published the first set of Price Control Review Reporting Rules ('the rules') setting out how DNOs should report cost information. These rules have subsequently been revised to incorporate the experience and lessons learnt from previous reviews. We have slightly streamlined the data requests by combining cost pools for similar activities with relatively low costs and removing or modifying data points that were not useful. For this year, we introduced two new tables (network loading and condition based replacement).

1.2. The definitions have been refined to alleviate interpretational and boundary issues. The rules for the 2006/07 RRP were published in March 2007 and are available on our website (see Associated Documents above). Following publication, two surveys were undertaken on boundary issues and subsequently additional guidance was issued around fault repairs/asset replacement which has been applied to both 2005/06 and 2006/07 data resulting in minor revisions to last year's RAV. 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 DNOs' audited regulatory accounts.

1.3. We have continued to investigate other areas where we identified there may be different interpretations of the rules to improve consistency and to monitor areas where costs have moved between early and final submissions of the RRP by DNOs.

Objectives

1.4. The rules provide a framework for the DNOs to report accurate and consistent information to us by completing the RRP and by submitting a formatted commentary document.

1.5. 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 us;
- 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

1.6. We recognise 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.

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

Processes for 2006/07

1.8. The process we followed was similar to that for previous years. Following receipt of submissions in mid July 2007, we 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. The visits have all been constructive and considered beneficial by both the DNOs and us in developing mutual understanding and knowledge.

1.9. The visits were structured so that DNOs were provided with a detailed agenda setting out our objectives to enable the companies to be adequately prepared and to utilise the available time efficiently. Discussions during the visits allowed us to obtain an understanding of each DNO's business structure and practices and the ways in which these impacted on costs during 2006/07. Expenditure against DPCR4 allowances was also reviewed including planned outturn figures for the remainder of DPCR4. Early indications of capex forecasts for DPCR5 (2010/11 - 2014/15) were also discussed.

1.10. There has been increased emphasis on understanding the investment planning processes including the key assumptions and models used by the DNOs in developing their longer term forecasts for DPCR5. This included a review of each DNO's approach to asset risk management and the robustness of their asset data and condition information. In addition DNOs' governance procedures and processes for preparation and submission of the annual reporting packs were discussed and our review was extended to perform some very limited audit procedures on a trial basis. The latter involved following audit trails to understand DNOs' processes more fully and to focus on particular reporting issues.

Quality of submissions

1.11. DNOs have generally adapted their internal reporting systems reducing the need for management estimation of cost breakdowns. Such estimations are subjective and can result in less accurate reporting. In our view, in some cases, there is still scope for further improvement in reducing the scope of estimation required.

1.12. DNOs have committed significant resources to the process, including input from senior staff, and we acknowledge the volume of work required in the preparation of data and information in accordance with the rules for this second year of DPCR4. Overall, the quality of data reported for 2006/07 reflects a continuing improvement in accuracy and comparability over data reported for 2005/06.

1.13. The review and visit process identified, to varying degrees, the necessity for revisions to DNOs' original submissions. The resubmissions resolved a number of issues and minor inconsistencies in treatment.

1.14. Our discussions with DNOs suggest that residual inconsistencies will mainly relate to the factors in paragraph 1.6 above. Following two surveys in early 2007 around the reporting of fault repairs/asset replacement and direct/indirect labour costs and the subsequent issuance of further guidance, these issues have been resolved in the DNOs' 2006/07 submissions. The intention was to place all DNOs in the position that we understood was the general industry practice at the last price review, notwithstanding that there were limited exceptions to that general basis. This work has resulted in some minor adjustments to 2005/06 RAV additions and these are reflected in the revised opening RAV in the tables.

1.15. We recognise that all DNOs have learnt from completion of the packs in previous years, the two surveys and through discussions both with us and between DNOs. DNOs have submitted more robust data this year. Notwithstanding the scope of improvements throughout the sector, some companies' first submissions in 2006/07 had specific weaknesses, and there remains room for further improvement to reach a higher initial standard in 2007/08.

1.16. Where DNOs had not previously committed adequate internal resources to the process this was noticeable in the overall quality of their submissions and in the need for subsequent revision, which in our view could generally be avoided. Those DNOs have generally recognised this and have taken remedial action to improve resourcing and internal review. Our observations are that where there are good internal governance procedures in place and a high quality pre-submission review by licensees this showed through in the lower number of issues identified by our review.

1.17. There were several resubmissions of 2005/06 data where errors and data inconsistencies were identified in addition to the adjustments identified as necessary to confirm treatment arising from the two surveys. This was a particular issue this year with both SSE and SPs' licensees. We welcome further discussion with DNOs on an ongoing basis where additional issues come to light.

1.18. 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 we expect further improvement in data quality in future years. We intend to make only minor changes to the rules for 2007/08 (i.e. to refine definitions where minor differences in

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

interpretation have been identified) to encourage DNOs who have not done so to develop their systems to collect data in the format required where this is appropriate and feasible.

1.19. We take compliance with licence conditions very seriously and expect licensees to augment their processes and systems, where necessary, to collect data so as to complete reporting to us in accordance with the rules. After three years of annual reporting, we consider that DNOs have had sufficient time to get to grips with the process and to understand what is required. We will therefore now be less accepting of repeated re-submissions to correct errors and differences of interpretations - these should be resolved prior to the first formal submission. Should any licensee fail to meet the requirements of the relevant licence condition we will look to take enforcement action. If licence breach is proven, this may result in a financial penalty.

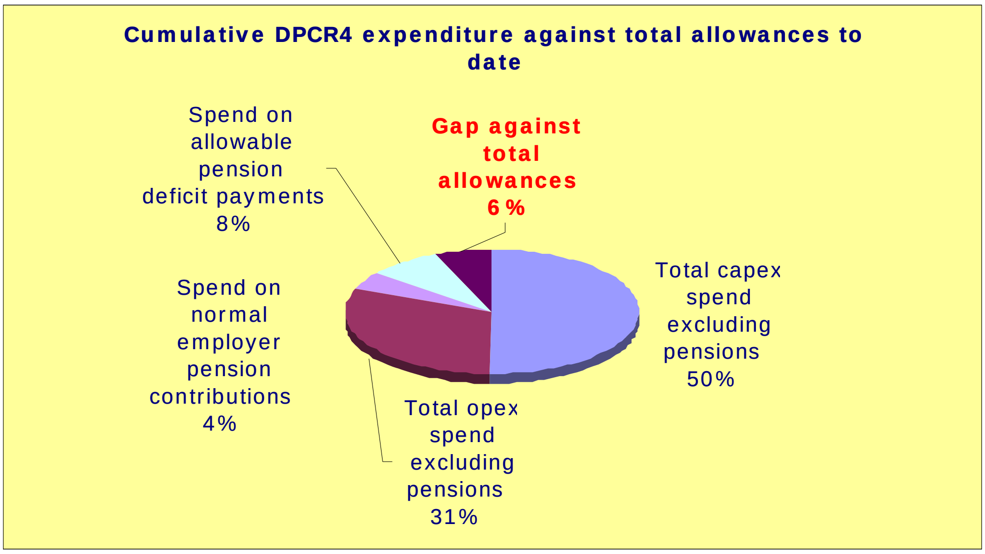
2. Industry performance

Chapter Summary

This chapter sets out the overall expenditure of the electricity distribution industry in 2006/07. It shows total costs activity analysis, operating, capital and pension expenditure across the DNOs, indicative Regulatory Asset Values and year-end regulatory gearing figures.

Cumulative DPCR4 expenditure

2.1. The graph shows for all DNOs the cumulative expenditure in the two years of DPCR4 to 31 March 2007 is 6% below the cumulative allowances for these two years.



2.2. Whilst most DNOs continue to underspend against their capex allowances, capex has increased over the last two years. DNOs are forecasting further material increases for 2007/08. DNOs have indicated that expenditure for 2007/08 is progressing to plan and that substantial resources are (in their view) now in place to deliver the required investment in the network. The capex underspend is partially offset by a smaller overspend on opex. The position has been discussed with the DNOs and we understand the reasons for this and now have more confidence in what they are going to deliver over DPCR4; this is currently forecast as a 6% underspend on capex.

2.3. It should be noted that opex overspends represent an additional expense for DNOs' shareholders, whereas capex underspend is shared with consumers through the capex incentive mechanism.

Total Costs Activity Analysis

Table 2.1: Activity Costs before allocation to direct opex and capex less customer contributions (excluding disallowed related party margins)

	Cash typical costs (note 4)										
	Direct activities					Indirect activities					
y/e 31 March 2007	Load related new connections & reinforcem't (net of contributions)	Non-load non-fault new & replacement assets (net of contributions)	Non-operational capex	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 (06/07 prices)											
CN West	9	72	3	27	11	25	21	29	3	2	**202**
CN East	14	45	3	29	14	24	21	30	2	0	**182**
UU	(6)	48	4	17	6	29	14	29	0	0	**141**
CE NEDL	1	39	5	16	10	13	13	16	1	18	**132**
CE YEDL	(4)	50	4	24	14	17	14	18	1	4	**142**
WPD S Wales	3	26	4	9	8	11	12	16	5	7	**101**
WPD S West	7	39	14	13	12	15	14	17	8	10	**149**
EDFE LPN	(3)	69	7	25	11	21	13	22	5	15	**185**
EDFE SPN	(4)	45	10	22	14	15	17	21	1	16	**157**
EDFE EPN	17	66	11	34	22	26	28	30	13	4	**251**
SP Distribution	3	51	7	15	9	20	18	22	3	18	**166**
SP Manweb	14	52	5	13	13	16	17	21	5	93	**249**
SSE Hydro	(3)	25	2	5	7	12	12	18	1	0	**79**
SSE Southern	8	48	13	21	12	23	22	26	2	25	**200**
Total	**56**	**675**	**92**	**270**	**163**	**267**	**236**	**315**	**50**	**212**	**2336**
2005/06 (06/07 prices)(note 6)	**125**	**571**	**63**	**258**	**167**	**247**	**237**	**316**	**31**	**283**	**2299**

Notes

1 Includes activities of Network Policy, Network Design, Project Management 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 as a 5 year lumpsum payment was made previously covering the DPCR4 period

5 Pension deficit payments are shown separately. In 2006/07 for SP Manweb (2005/06 for UU and CN) this included lump sum payments. The amounts shown are before application of the disallowance for ERDCs and non-distribution activities - see Table 2.3

6 The 2005/06 costs have not been amended for the changes arising from the faults and labour cost boundary surveys or any other prior year adjustments

2.4. Table 2.1 above shows a summary of the activity breakdown of costs for year ended 31 March 2007 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 our website (see Associated Documents section above).

2.5. This is the second year that such disaggregated data has been published. Unlike last year we have removed related party margins to show data on a similar basis to that we use for analysis. 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.

2.6. 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, and include all severe weather events that meet the relevant exceptionality requirement defined in annex B of special condition C2 of the electricity distribution licence. With certain exceptions (e.g. early retirement deficit costs) restructuring and atypical costs are allowable in computing additions to RAV.

2.7. The individual activity categories shown 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 the DNOs allocate indirect costs to direct activities based on their own internal reporting and accounting criteria.

Operating Costs

2.8. Table 2.2 below shows operating costs (opex) for 2004/05, 2005/06 and 2006/07. 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, prepayment of pensions, restructuring and reorganisation costs. The year saw more severe weather events than the benign situation in 2005/06, costs increased to £24m, they were £3m in 2005/06 and £17m in 2004/05.

2.9. Revenues from relevant excluded services have increased this year by 15% (£9m across all DNOs) to £69m. Revenues are treated as a proxy for costs; hence this has the impact of depressing opex measured on a price control basis by the adjustment for the difference between forecast and actual excluded services revenue being £27m. Table 2.2 also shows the DPCR4 opex allowances and the over/(under) spend to allowances.

2.10. DNOs reported net opex is lower by £11m than actual expenditure by the proceeds from the disposal of non-operational assets, which in accordance with the DPCR4 Final Proposals document is offset 76.5% against opex and 23.5% against capex.

2.11. In 2006/07 the level of operating costs (excluding all pensions, rates, licence fees and depreciation but including atypicals) across the industry is 9% higher than the allowances for the year. Table 2.2 above shows how companies have moved from their 2004/05 expenditure levels.

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

year ended 31 March £m (06/07 prices)	Actual 2005	Actual 2006	Actual Gross Opex 2007	Disposals & excluded service adjustment 2007	Actual Net Opex 2007	DPCR4 allowance 2007	Over / (under) spend to allowance	Over / (under) spend to allowance %
CN West	58	58	66	(2)	64	54	10	18%
CN East	59	66	71	(7)	64	58	6	11%
UU	68	51	54	(9)	45	52	(8)	(15%)
CE NEDL	36	38	41	(0)	41	37	3	9%
CE YEDL	47	46	53	(1)	52	45	7	15%
WPD S Wales	29	32	31	(0)	31	35	(4)	(12%)
WPD S West	42	49	50	0	50	42	8	19%
EDFE LPN	52	44	59	(5)	53	46	8	16%
EDFE SPN	61	55	57	(3)	54	46	8	17%
EDFE EPN	80	79	95	(6)	89	71	18	25%
SP Distribution	50	55	49	(2)	47	49	(1)	(3%)
SP Manweb	56	56	48	(1)	47	41	7	16%
SSE Hydro	28	31	30	(1)	29	33	(4)	(11%)
SSE Southern	55	58	67	(0)	67	60	7	11%
Total	**723**	**718**	**771**	**(38)**	**733**	**670**	**63**	**9%**

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

2.12. In the table costs are also reported net of related party margins, which are disallowed where the affiliate's turnover external to the ownership group is less than 75%. Not all DNOs have affiliates charging margins; where they do these are mainly for connections and contracting activities. Disallowed related party margins total £52m.

2.13. Insurance costs have reduced by 12% and include the cost of uninsured third party claims which remain static year in year. Insurance is reported within the Finance and Regulation Activity and grouped with Business Support Costs in Table 2.1 above. The risks insured and levels of cover vary between DNOs, depending on attitudes to risk and corporate policy. The majority of companies have discontinued overhead line cover (storm cover) which had become prohibitively expensive. With one exception, all licensees use captive insurers to minimise premiums. Margins in captive related parties are disallowed in calculating RAV, in the same way as for other related parties. We recognise that captives are generally set up to match premiums and claims over the long run and we are review how we treat captive insurance margins.

Inspections and Maintenance

2.14. Overall inspections and maintenance (I&M) costs are up £5.9m (5%) on 2005/06.

2.15. Traditional inspection and maintenance practices have been updated to facilitate the capture of more detailed condition information usually using hand held devices with preformatted templates. This has been driven by the requirement for more accurate condition assessment information as a key input to the development of 'health indices' (see paragraph 2.56 below).

2.16. 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, although in general inspections and maintenance activities are still undertaken on a cyclical basis.

2.17. The frequency of inspections and maintenance activities is continually reviewed by DNOs with a number achieving efficiencies by optimising intervals to achieve standardisation and consistency across different asset types. Most DNOs have also introduced work management systems aimed at optimising the scheduling and allocation of inspections and maintenance activities.

2.18. For overhead lines the use of helicopter and high definition photographic surveying has become more standard practice in addition to the conventional line walking inspections. The use of online monitoring is also increasing, particularly for grid transformers and underground cables.

2.19. 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 repairs and additional site security. This is having a negative impact on routine I&M volumes and is increasing expenditure.

Substation electricity

2.20. When comparing inspections and maintenance spend across DNOs cognisance must be taken of the differing treatment of the payment for unmetered electricity usage at licensees' substations. Seven DNOs pay the incumbent supplier, in four areas there is a related party provider for this, whilst for the remainder unmetered substation electricity is accounted through losses and is included in their losses incentive when assessing revenues. The amounts are not significant and total £7m at the DNOs who pay. However, the situation is anomalous between DNOs and requires adjustment to provide consistent data.

Fault costs

2.21. Overall fault levels (excluding exceptional weather events) and hence costs are up £12m (5%) from 2005/06. That year was a relatively benign year for weather related events. There were also some changes in the 2005/06 numbers on those reported in last year's Cost Report due to reclassification. The changes have arisen from the conclusion of the faults survey and the associated revised guidance.

2.22. There has been a fivefold increase in the costs of exceptional weather events amounting to £20m arising from storms in July and December 2006 and January 2007. These events account for 3% of total net operating costs compared to 0.5% in 2005/06.

Tree cutting

2.23. 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) in nine DNOs and a reduction in five as the backlog issue has been addressed. Overall costs increased by £11.6m.

2.24. There are a number of different approaches to managing and resourcing tree cutting ranging from fully out-sourced to fully in-sourced. A number of DNOs are currently reviewing their approach with a current preference for moving back to internal resourcing due to contractor labour retention issues and a desire for greater control over quality.

Reporting of Labour and Fault Costs

2.25. During the 2005/06 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 undertook further work in this area (see 1.14 above) and concluded there was broad consistency in treatment but that it was appropriate to issue additional guidelines to bring all DNOs onto a consistent basis for regulatory reporting and the computation of RAV. There remains as a boundary issue the treatment of operational site engineers and we intend carrying out a further survey in 2008 to resolve this.

Non-Operational new and replacement assets

2.26. For regulatory cost reporting purposes, the Non-Operational New and Replacement Assets cost category 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. Such costs increased by 55% on 2005/06 levels. These costs include £9m associated with reorganisation and centralisation of various activities across one ownership group reported as atypical costs.

2.27. Most companies have ongoing programmes to replace information systems. Companies generally aim to avoid peaks and troughs of expenditure, although some DNOs had planned comprehensive IT replacement projects. Such costs increased by 29% in the year.

2.28. Some DNOs own their vehicle fleets whereas others lease them. Specialist vehicles tend to be purchased by all DNOs. In the year vehicle replacement increased by 137% despite a move by some DNOs to leasing.

2.29. During this year's review it became clear that there has been an inconsistent treatment across licensees of small tools and equipment, where some had followed their statutory accounting policies to report these costs. Consequently both current and prior year treatment has been conformed so that such costs are treated consistently. This resulted in a small reduction in the 2005/06 RAV (£1m).

Pensions

2.30. This year has seen further payments to pension schemes by DNOs to make up deficits, notably at SP Manweb. United Utilities made a substantial one-off pension payment, treated as paid on 1 April 2005, which comprised not only a deficit repair payment but an advance payment for five years' worth of normal contributions. This accounts for their 98% variance to the allowance. Most DNOs are making lower than forecast annual deficit repair/normal pension contributions. For the English and Welsh DNOs, the triennial valuations of their pension schemes as at 31 March 2007 are due in 2007/08 and the impact on contribution levels and deficit funding should be seen in 2008/09.

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

£m (2006/07)	Normal Employer Pension contributions	Allowable Pension Deficit payments	Total allowable pension payments	DPCR4 Pension Allowance	Over/(under) spend to allowance
CN West	7	1	9	18	(53%)
CN East	6	0	6	15	(61%)
UU (see note)	2	(1)	0	18	(98%)
CE NEDL	5	13	18	20	(7%)
CE YEDL	6	4	10	12	(12%)
WPD S Wales	7	5	12	11	8%
WPD S West	10	6	17	16	1%
EDFE LPN	7	18	25	25	1%
EDFE SPN	8	13	21	23	(11%)
EDFE EPN	12	4	16	14	18%
SP Distribution	6	0	6	5	2%
SP Manweb	6	74	79	18	347%
SSE Hydro	5	0	5	4	9%
SSE Southern	7	25	32	34	(5%)
TOTAL	**93**	**163**	**256**	**233**	**10%**

Note: In 2005 UU made a 5 year lump sum advance payment of normal and deficit contributions, apart from a smaller scheme no contributions are being made.

2.31. All of the DNOs are maintaining measures to manage their exposure to the risk based element of the levy they are subject to under the Pension Protection Fund scheme.

Capital Expenditure

Outturn for 2006/07

2.32. Table 2.4 below shows total capital expenditure (excluding all pension costs) on new and replacement assets for 2006/07 compared to 2005/06 and 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 document and include the impact of the reduction for the amount allowed into capex referred to in the notes to Table 2.2.

Table 2.4: Capital Expenditure (excluding all pension costs)

	Actual	Actual	Actual	Average annual DPCR4 Allowance	Percentage under/(over) spend to allowance
y/e 31 March	2005	2006	2007	2007	2007
£m (06/07 prices)					
CN West	85	111	129	125	(2%)
CN East	84	89	112	124	10%
UU	107	87	78	116	33%
CE NEDL	54	63	66	70	6%
CE YEDL	93	97	76	93	18%
WPD S Wales	50	46	49	50	1%
WPD S West	71	70	74	72	(3%)
EDFE LPN	62	88	99	112	11%
EDFE SPN	87	93	71	120	41%
EDFE EPN	111	114	135	173	22%
SP Distribution	73	74	88	94	6%
SP Manweb	94	90	97	101	4%
SSE Hydro	39	40	41	53	23%
SSE Southern	101	97	95	141	32%
Total	**1,111**	**1,159**	**1,210**	**1,444**	**16%**

2.33. While the total capital expenditure (capex)[2] for the industry was 16% below the allowances for 2006/07, there were significant variances between actual costs and allowance in the companies, notably the large under-expenditure relative to

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

allowances in EDFE SPN and EPN, UU, SSE Hydro and Southern. It should be noted that the capex allowances for DPCR4 were not explicitly profiled and therefore annual comparisons can be misleading. The actual profile of capital expenditure across DCPR4 is a management issue for the DNO and will be dependent on actual network requirements.

2.34. Overall there is a 4% increase in capex over 2005/06 although there are notable decreases for UUE, CE NEDL, EDFE SPN and SSE Southern. Factors highlighted as drivers for these, mostly unplanned, reductions in capex include:

- unexpectedly high levels of load related expenditure (customer funded) resulting in the need to defer some asset replacement work;
- phasing of customer contributions;
- slippage of major load related projects (usually due to planning issues); and
- general delays and deferrals of schemes.

Forecast outturn DPCR4

2.35. As part of this year's cost review DNOs also provided their forecast outturn for DPCR4. In total capex across the industry is forecast to outturn 6% below the allowance ranging from a 13% underspend to 2% overspend. A number of factors where highlighted as drivers for the forecast underspend including:

- the treatment of new connections and contracting activities undertaken by affiliates (connection and contracting margins of affiliates are excluded from RAV and therefore capex);
- management decision not to spend the sliding scale;
- reduction in replacement volumes due to better condition information;
- forecast load increases not materialising as planned; and
- delays in ramping up investment post DPCR4 settlement (discussed below).

2.36. To achieve their planned outturn for DPCR4 most DNOs are forecasting a material increase in expenditure from 2006/07 to 2007/08. A small number of DNOs have already achieved the level of expenditure required and are forecasting a flat profile for the remainder of DPCR4. Across the industry the forecast increase from 2006/07 to 2007/08 is 21% (£254m), ranging from 4% to 59%. The majority of DNOs indicated that outturn for 2007/08 is progressing to plan.

Factors affecting delivery of capex

2.37. The majority of DNOs, since 05/06, have achieved material increases in capex although most indicated that outturn has been below their own internal plans. Factors highlighted as affecting the companies' ability to deliver the increased capital investment plans include:

- shortage of skilled labour (internal and external);
- delays in mobilising the contractor base;

- delays to major reinforcement projects due to planning issues; and
- adverse weather diverting resources from capex to fault repairs.

2.38. DNOs are increasing internal resources by recruiting staff at all levels including graduates and apprentices. In some cases, they are planning to take on and retrain ‘mature workers’, often with a technical background. All of the DNOs, however, are presently experiencing strong competition for skilled labour both within the distribution industry and from other sectors, including electricity transmission.

2.39. The majority of DNOs have now developed new processes and introduced new ways of working regarding the procurement and management of external contractors. In most cases DNOs have now reached a level of resourcing, internal and external, required to deliver their capital expenditure programmes for the remainder of DPCR4.

2.40. Additional issues were highlighted as not currently constraining capex but which are requiring careful management and which may become constraints in the future:

- increasing units costs and contracting rates;
- restricted availability of plant from manufacturers with long production and delivery times; and
- network access constraints (planned outages).

2.41. DNOs indicated that the continuing increases in copper and steel prices, amongst other things such as increasing demand, are driving a large increase in the ex-factory unit costs of distribution equipment. Primary transformer and cable prices have increased significantly. It now appears that any efficiency gains made during DCPR4 may be more than offset by increased unit costs.

2.42. The majority of DNOs commented that due to increasing demand for resources, both internal and external labour costs are increasing.

2.43. In addition, all DNOs highlighted an unprecedented increase in manufacturing lead times particularly for transformers and certain voltages of underground cable and switchgear. DNOs indicated this has been driven by a large increase in worldwide demand for distribution equipment of which the DNO (and Great Britain in general) requirements account for a relatively small share.

Initial forecast for DPCR5

2.44. As part of this year’s cost reporting process DNOs were asked to provide an early indication of their capex forecast for DPCR5 (2010/11 - 2014/15). There were significant variances between DNOs in terms of percentage change from DPCR4 actuals, although this was compounded by different accounting assumptions regarding the treatment of indirects, pensions, and faults costs.

2.45. The underlying assumptions and approaches behind the forecasts were discussed in detail at this year's cost visits. In general the forecasts were developed via either a top-down approach (based on high level modelling) or bottom-up (based on internal schemes addressing known loading or condition issues), or a combination of both.

2.46. In broad terms the estimated increase in asset replacement (NLRE) for the majority of DNOs was between 10%-25% on a like for like basis.

2.47. There were large variations in the robustness of the forecasts provided by the DNOs. A number of DNOs were able to provide existing investment plans which are produced on an ongoing basis and form the basis of their own board approved investment plans, while other DNOs carried out simple high level analysis purely for the proposes of providing forecasts to us.

2.48. DNOs highlighted a numbers of areas where further guidance would be required regarding key assumptions in order to produce forecasts for DPCR5 on a consistent basis:

- quality of supply targets and incentive rates;
- future network risk and loading;
- future fault rates and underlying asset condition;
- accounting assumptions regarding indirects, pensions, and faults costs;
- current and future requirements of ESQCR;
- impact of BT21C (i.e. proposed changes to communications services offered by BT);
- demand growth for both load and DG; and
- the impact of any changes to ER P2/6 or the introduction of any new requirements to reduce the impact of high impact low probability (HILP) events.
-

Asset data

2.49. This year there was an increased focus on the quality of the asset data and age profiles provided to us by the DNOs. This was to ensure a consistent and robust data set for analysis as part of DPCR5 and to avoid the prolonged process of data cleansing that was required in the early stages of DPCR4.

2.50. For linear assets (overhead lines and underground cables) almost all DNOs captured asset data, including length, in a vectorised GIS system. Those DNOs without full vectorisation (usually full at HV and above but incomplete for LV) are currently working to achieve full vectorisation. In general the DNOs have a relatively high level of confidence in the accuracy of network length which is expected to improve further over time as annual cleansing and error correction is undertaken.

2.51. For plant assets (transformers, switchgear, other substation equipment and OHL supports and towers) asset quantities are captured in standard asset registers which in the majority of cases also capture condition information and I&M records. Again, DNOs generally have a high level of confidence in this data.

2.52. The majority of DNOs' GIS systems and plant databases are linked to the real time operational control systems which acts as a check since assets must be in the asset databases before they can be added to the real time control systems.

2.53. Asset age profiles which capture the age of each individual asset on the network (and are a key input to any age based replacement modelling) are generally considered to be fairly robust for plant assets but are generally considered to be less accurate for linear and LV assets. In many DNOs the removal of linear assets from age profiles is distributed across the age profile due to lack of accurate age information.

Asset risk management

2.54. Currently ten of the DNOs have achieved PAS55 compliance with the remaining intending to seek PAS55 certification in accordance with our proposed timetable, i.e. by April 2008.

2.55. The majority of companies with PAS55 certification indicated that gaining certification had not materially changed actual practices but had driven requirements for improved documentation and the use of consistent language in describing asset management documents and processes. This has generally raised the profile of asset management.

2.56. Risk is quantified by most DNOs when preparing capex investment plans. This usually involves ranking investments based on the risk the investment is addressing. Quantification of risk is being further advanced via the development of health indices (as discussed below). Only a small number of DNOs have developed a method for a quantified comparison of load and non load related risks.

2.57. As part of their board approval process for capex expenditure a number of DNOs specifically identify the risks being addressed by the investment plan and what risks remain requiring management.

Asset condition data

2.58. The majority of companies, supported by external expertise, have adopted or are developing health indices to enable asset condition related risks to be quantified and deterioration rates to be monitored and forecast.

2.59. The initial work undertaken has identified those aspects of asset condition affecting reliability and asset life which can be identified by inspection and maintenance. When identified, asset condition assessment criteria are established and embedded in data collection systems allowing population 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 (and particularly for the higher volumes of LV and HV assets), it will be some time before asset condition databases are fully populated, and even longer before deterioration trends can be fully assessed.

2.60. Nevertheless, at primary voltage levels some inspections take place on a shorter inspection cycle and more condition information should be available for these. A small number of DNOs are also undertaking specific asset condition surveys in order to populate the condition data in advance of relying on normal inspection and maintenance intervals.

2.61. Although some companies propose to use analytical techniques based on health indices for the preparation of their forecast asset replacement expenditure for DPCR5 and beyond, they accept that in some cases only a sample of condition information will be available for this purpose. In addition the development of deterioration rates and associated algorithms to convert health indices to future investment need is still in the early stages of development and there is limited experience using this approach.

Capex schemes

2.62. In addition to a desk top review of the five largest load- and non-load-related scheme papers as part of the cost review process, the end to end life cycle of investment schemes was discussed in detail during the cost visits.

2.63. The majority of DNOs have good processes and polices for developing scheme papers and sanctioning investment. A small number of DNOs achieve leading practice, including undertaking comprehensive post investment appraisals, benchmarking of unit costs and deliverables, providing £/MW of increased network capacity, producing comprehensive cost benefits analysis including the quantification of risk and producing consistent, well-documented, company-wide multi-step approval processes.

2.64. For the majority of DNOs there is a material degree of scheme churn (i.e. different schemes being undertaken from those set out in forecasts prepared during the last price review), particularly for load-related expenditure, 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. In addition scheme phasing, the scope of work and forecast costs have also varied from earlier predictions.

Quality of Service Investments and Initiatives

2.65. Most DNOs plan to continue investing in network 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 minimise the consequence of faults and are incorporating automatic sequential switching programmes within their network control systems (network automation).

2.66. The majority of DNOs have been operating or are currently introducing operational practice aimed at restoring the highest number of customers possible within a given time following a supply interruption, usually around 60 minutes, in order to reduce customer minutes lost. Initiatives include: identification of optimum network switching points (over and above normal open points), the use of larger switching teams (up to 4 people per fault), live line working, 'pinging' of mobile phones to determine closest available resources and the use of dedicated fault teams for repair and restoration within defined areas.

2.67. Some companies see less scope for further improvements in quality of service output measures over the remainder of the price control period as 'easy wins' are already fully implemented, although this also depends on the DNOs' current performance against their information and incentives scheme targets. Uncertainty around targets and incentive rates for DCPR5 is also an issue in assessing benefits of investment at the tail end of DCPR4.

2.68. For further detail on DNOs' quality of service performance, please see our 2006/07 quality of service report[3].

Distributed Generation Incentive

2.69. The connection of relevant distributed generation (DG) to distribution networks under the new incentive mechanisms (from 1 April 2005) has been slower than expected. To date 166 MW of distributed generation has been connected under the DG incentive (26 MW in 05/06 and 140 MW in 2006/07).

2.70. Some DG connections are still being made under contractual arrangements put in place before 1 April 2005 (non-relevant DG) although the number of 'non relevant' DG new connections will decrease over time.

Additions to RAV

2.71. Our current view of the additions to each DNO's Regulatory Asset Value is shown in Table 2.5 below. In calculating the RAV rolled forward from 1 April 2005, we have applied the methodology set out in Appendix 1 of the final proposals document.

2.72. In reviewing reported costs we have been particularly concerned to ensure:

[3] Available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/QualofServ/QoSIncent/Pages/QoSIncent.aspx

- 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 except for non-operational assets;
- 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 by a related party (in accordance with the definitions in the licence);
- the identification of adjustments to 2005/06 reported costs;
- 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).

2.73. We have rolled forward the provisional RAV on the same basis for all licensees in accordance with the methodology set out in Appendix 1 of the final proposals document. Adjustments to 2005/06 values have been made following on from work to clarify the treatment of costs relating to fault repair/asset replacement and direct/indirect labour boundary surveys (see paragraphs 1.14 and 2.25 above). These adjustments have been reflected through revisions to the opening RAV balances signalled last year. Where additional information has become available the rules clarified or for the correction of errors the opening RAV has also been restated.

RAV roll forward

2.74. Table 2.5 below shows our current view of the RAV roll forward for the year ended 31 March 2007. The provisional RAV figures in the table have been discussed with the DNOs concerned, although in some cases DNOs have not agreed the figure shown. The RAV will be finalised at the next price review.

2.75. Across the industry, actual RAV additions are 14% lower (2005/06 - 15% lower) than the price control allowances. RAV additions are materially lower at EDF Energy's DNOs (circa 23%), Scottish & Southern DNOs (27%) reflecting their capital investment activity and United Utilities (by 38%) reflecting partly their investment activity and partly the impact no pension payments in 2006/07 due to their capitalising five years' payments in 2005/06. RAV additions are higher at Scottish Power (by 13%) reflecting the impact of capitalising part of their additional pension payments at SP Manweb. RAV balances brought forward at 1 April 2006 have been revised following the outcome of the two boundary surveys and other amendments following this year's review to conform treatment across the industry, being a reduction of £9m in RAV.

Table 2.5 RAV roll forward - Ofgem provisional view

	Balance b/f 1 April 2006	Memo: Additions per Final Proposals	Additions Actual	Deprecia-tion	Balance as at 31 March 2007	Balance as at 31 March 2007 (see note)
	£m (2006/07)					£m(nominal)
CN West	1141	**136**	133	(86)	**1188**	**1216**
CN East	1093	**133**	115	(85)	**1123**	**1148**
UU	1097	**127**	78	(84)	**1091**	**1116**
CE NEDL	691	**82**	77	(53)	**714**	**731**
CE YEDL	930	**100**	82	(70)	**942**	**963**
WPD S Wales	647	**56**	56	(54)	**649**	**664**
WPD S West	817	**81**	84	(63)	**838**	**857**
EDFE LPN	1020	**126**	113	(79)	**1054**	**1079**
EDFE SPN	743	**133**	83	(56)	**769**	**787**
EDFE EPN	1261	**181**	144	(95)	**1311**	**1341**
SP Distribution	1369	**97**	91	(126)	**1334**	**1365**
SP Manweb	876	**111**	143	(65)	**953**	**975**
SSE Hydro	803	**56**	44	(58)	**789**	**807**
SSE Southern	1509	**160**	114	(119)	**1504**	**1538**
Total	**13997**	**1578**	**1357**	**(1094)**	**14260**	**14587**

Notes:
Opening RAV balances have been decreased by prior year adjustments of £9m as noted below gross of depreciation
The RAV balance at 31 March 2007 has been calculated using the average of the RPI for March & April 2007
Columns may not cast due to roundings

2.76. 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 capex allowances by approximately 6% (excluding pension costs) over the DPCR4 period.

Gearing to RAV

2.77. Table 2.6 below shows each DNO's gearing (defined as net debt to RAV), which is our primary measure of gearing for the 2005-10 price review. This is based on net debt at the licensee and does not include other group debt.

Table 2.6: Gearing to RAV

	Net Debt	RAV	Gearing at 31 March	
	as at 31March 2007 £m (nominal)		2007 %	2006 %
CN West	407	1,216	33%	52%
CN East	295	1,148	26%	40%
UU	480	1,116	43%	52%
CE NEDL	340	731	46%	44%
CE YEDL	475	963	49%	47%
WPD S Wales	27	664	4%	22%
WPD S West	321	857	37%	41%
EDFE LPN	504	1,079	47%	54%
EDFE SPN	528	787	67%	71%
EDFE EPN	701	1,341	52%	60%
SP Distribution	700	1,365	51%	56%
SP Manweb	457	975	47%	49%
SSE Hydro	475	807	59%	48%
SSE Southern	877	1,538	57%	60%
TOTAL	**6,585**	**14,587**	**45%**	**51%**

2.78. The gearing ratio used in the DPCR4 cost of capital was 57.5% compared to the overall industry weighted average gearing of 45% (2005/06 - 51%). The 2005/06 ratios have been amended to take out intra-company trading balances and for reported errors. 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 decreased by £391m.

2.79. Net Debt and gearing in WPD South Wales is low as it has lent its parent £336m, primarily to fund the 2006/07 debt maturities, utilising the £218m proceeds from the external bond issuance by WPD South Wales in December 2006.

2.80. The table does not include guarantees provided by licensees for parent company debt of £1.97m jointly by SP Distribution and by SP Manweb's immediate parent company and with SP Transmission.

2.81. 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, 2006/07 was the third year for which the DNOs have submitted information under the rules.

3.2. Minor refinements to the definitions and guidance will be made in the rules. The intention is to eliminate the inconsistencies identified this year in data reported by DNOs and to remove differences of interpretation and incorporate the outcome of the boundary surveys.

3.3. Our intention is to introduce, following consultation with the DNOs, two further tables covering network fault levels and a network summary table bringing together high level activity indicators such as maximum demand, load growth, number of new connections and units distributed.

3.4. We intend to issue the rules for 2007/08 in February 2008.

3.5. Our next electricity distribution cost report will cover the year ended 31 March 2008, the third of five years of the DPCR4 price control period. We currently intend to publish the cost report for 2007/08 in December 2008.

3.6. We started to consider and examine alternative ways of using the reported data for cost assessment for DPCR5 during 2006/07 and will continue this in discussion with the DNOs as the price control work commences through 2008.

Appendices

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Appendix 1 - Response and Questions

1.1. We welcome views on the type and format of information that users of this report would find useful.

1.2. Please send your comments to :

Bill McKenzie
Senior Manager, Cost Review
Ofgem
9 Millbank
London
SW1P 3GE
william.mckenzie@ofgem.gov.uk

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 in their respective distribution services areas. 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 16 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 £62 per year.

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

	Total No of Customers	Length of circuit km		
		Overhead	Underground	Total
CN West	2,422,495	23,964	37,707	61,671
CN East	2,551,645	22,805	47,639	70,444
UU	2,326,264	13,128	43,149	56,277
CE NEDL	1,550,686	14,899	24,279	39,178
CE YEDL	2,230,612	13,656	38,176	51,832
WPD S Wales	1,070,179	18,266	16,394	34,660
WPD S West	1,488,592	28,463	20,966	49,429
EDFE LPN	2,241,291	45	35,555	35,600
EDFE SPN	2,230,146	12,876	38,973	51,849
EDFE EPN	3,466,502	34,598	59,349	93,947
SP Distribution	1,967,920	21,143	40,564	61,707
SP Manweb	1,464,592	21,534	26,802	48,336
SSE Hydro	709,201	31,269	14,952	46,221
SSE Southern	2,858,026	27,525	47,307	74,832
Great Britain	28,578,151	284,171	491,812	775,983

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.[4]

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[5].

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[6]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[7]

[4] entitled "Gas Supply" and "Electricity Supply" respectively.
[5] 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.
[6] 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.
[7] 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[8] 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[9] 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.

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

Appendix 5 - Glossary

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

Electricity Distribution Price Control Review Price control cost reporting rules: Instructions and Guidance (version 2.21) March 2007:

http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/CostRep/Documents1/Cost%20Reporting%20Rules%202006-07%20V2%2021.pdf

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. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk