Electricity Distribution Price Control Review

Final Proposals

November 2004 265/04

Summary

This paper sets out Ofgem's Final Proposals for the Electricity Distribution Price Control Review, taking account of comments received in earlier consultations. The proposed package of measures will best protect the interests of consumers whilst providing sufficient revenue to allow the distribution businesses to finance their activities and comply with all of their obligations. The companies will form their own view in deciding whether to accept the proposals – if they do not Ofgem will refer the matter to the Competition Commission.

Context of the price control review

Ofgem's principal objective is to protect the interests of consumers – both in terms of the charges they pay and the quality of service they receive. In developing these proposals, Ofgem has also had regard to its other statutory duties, including both its duty to ensure that licensees can finance their activities and those relating to the environment. The potential effects of the Government's energy policy have been taken into account.

The review has been conducted against a background of recent increases in retail prices and concern about security of supply and environmental issues. Challenges such as these have required the RPI-X regulatory framework to evolve whilst continuing to deliver benefits to consumers and incentives to companies. The need for increased investment in the networks has been fully recognised. This review has sought to secure this investment, deliver a better quality of service and facilitate the connection to distribution networks of renewable generation, whilst maintaining pressure on distribution companies to be efficient and provide consumers with value for their money.

Key issues

Earlier Ofgem consultation papers highlighted three key themes:

- **incentives for investment and efficiency** – some of the companies forecast very significant increases in investment - others less so. In total, companies requested an increase of around 50 per cent from current levels of expenditure to maintain current service levels. Ofgem has challenged the companies' plans to ensure the

price controls provide value for money. An innovative incentive mechanism has been developed to accommodate the range of approaches. In total these proposals allow for investment of £5.7 billion over the years 2005 – 2010 to deliver improved performance, an increase of 48 per cent over expenditure in the current price control period.

Final proposals for capex allowances 2005 -2010

DNO	Actual / forecast expenditure 2000-2005	Total allowance for 2005-2010	Increase
	£m	£m	
CN - Midlands	336	501	49%
CN - East Midlands	301	485	61%
United Utilities	347	466	34%
CE - NEDL	228	277	22%
CE - YEDL	242	371	53%
WPD - S West	221	283	28%
WPD - S Wales	191	186	-3%
EDF - LPN	260	452	74%
EDF - SPN	283	487	72%
EDF - EPN	438	697	59%
SP Distribution	253	361	43%
SP Manweb	240	404	68%
SSE - Hydro	165	204	23%
SSE - Southern	375	561	50%
Total	**3882**	**5734**	**48%**

Note:
The figures shown here include investment to improve quality and exclude capitalised faults and pension deficit costs

Consistent with this focus on investment, the cost of capital used falls within the upper half of the range presented in the March 2004 Policy Document. It uses a cost of equity of 7.5 per cent real post-tax, which is at the top end of the range previously proposed. Overall, the proposed cost of capital is 4.8 per cent post tax. Taking account of the additional returns provided under the sliding scale mechanism, companies can expect to earn up to 5.0 per cent if their costs match the allowances and performance is in line with the price control targets.

Companies have achieved significant efficiency savings during the existing price control. Whilst the benefits of these savings will be shared with consumers from

April 2005 companies must continue to seek out further efficiency savings. To promote this objective, Ofgem has maintained relatively strong operating cost incentives whilst taking into account increases in costs that are outside the companies' control.

Incentive regulation requires that genuine efficiencies should be rewarded. At this review, a substantial process of data normalisation and adjustment has been required to ensure comparability between companies and consistency with the previous review. The review process needs to continue to improve: with the support of the companies, Ofgem will therefore institute a more effective cost reporting mechanism;

- **quality of service** – consumers value quality and security of service as well as the price that they pay. Surveys of consumers' priorities suggest that they are willing to pay more for improved service – but only up to a certain point. The Final Proposals therefore incorporate targets for significant improvements in performance, stronger incentives to exceed those targets and streamlined arrangements to provide compensation for prolonged outages following severe weather; and

- **responding to the challenge raised by the Government's objectives for renewable energy -** Ofgem has developed revised connection charging arrangements and new incentive arrangements to encourage DNOs to respond proactively to connection requests, removing regulatory obstacles to the achievement of the Government's targets for renewable energy.

The fundamental approach established in previous consultations remains generally valid and represents a major contribution to protecting the interests of customers. In particular, the quality of service targets and capital expenditure analysis and operating cost regressions are all unchanged from those in the September Update paper. However, various detailed adjustments have been made, which overall, net to zero in P0 terms, leaving the decision on the cost of capital as the main driver of change in the P0 calculations from the previous proposals. The adjustments:

- provide additional operating cost allowances for single DNOs (ie those that were not merged with another DNO in the 2002/03 base year), further recognise the impact of regional factors on central London and provide an additional reward for cost reductions in 2003/4;

- update pensions allowances to include latest information on deficits, contribution rates, pensionable salaries and the timing of recovery of the deficits;

- adjust tax allowances to reflect revised data for the forecast opening capital allowance balances at April 2005 and recognise that pension costs are expected to be allowable for tax in the year paid; and

- include a small number of other minor corrections and adjustments to the RAV calculation and 2004/05 revenues and include the expected impact of the Innovation Funding Incentive.

The financial modelling undertaken by Ofgem shows that these proposals are consistent with all companies maintaining a credit rating comfortably within investment grade. To improve the financial position of EDF-SPN, these proposals incorporate two specific changes in respect of that company only: the provision of additional revenue and a change to its X factor to target revenue in the years in which it is most needed.

Implications for distribution charges

The price changes in April 2005 (the so-called P0s) now proposed, compared to the Initial Proposals and the September Update, are set out below. In subsequent years, prices will be allowed to increase in line with inflation (i.e. X = 0) except as noted below. Distribution charges account for around 25 per cent of consumers' final bills so the changes in final prices that may arise would be significantly less than the figures shown here.

Final proposals for P0

DNOs	June Initial Proposals	Change	September Update	Change	November Final Proposals
	%	%	%	%	%
CN - Midlands	-6.5%	2.0%	-4.5%	1.6%	-2.9%
CN - East Midlands	-10.8%	3.3%	-7.5%	1.8%	-5.7%
United Utilities	-1.8%	7.4%	5.6%	2.4%	8.0%
CE - NEDL	-11.5%	8.6%	-2.9%	-0.8%	-3.7%
CE - YEDL	-14.7%	1.8%	-12.9%	3.7%	-9.2%
WPD-South West	-0.2%	1.8%	1.6%	-0.1%	1.5%
WPD-South Wales	1.7%	5.6%	7.3%	-1.1%	6.2%
EDF - LPN	-2.5%	-1.7%	-4.2%	1.8%	-2.4%
EDF - SPN (note 2)	-3.7%	6.7%	3.0%	4.2%	7.2%
EDF - EPN	-4.6%	2.5%	-2.1%	2.0%	-0.1%
SP Distribution	8.4%	2.2%	10.6%	1.3%	11.9%
SP Manweb	4.0%	-9.5%	-5.5%	-0.4%	-5.9%
SSE - Hydro	-0.1%	2.8%	2.7%	1.2%	3.9%
SSE - Southern	6.1%	3.1%	9.2%	0.1%	9.3%
Average	**-2.5%**	**2.5%**	**0.0%**	**1.3%**	**1.3%**

Note:
1. The P0 figures for November include allowances for Innovation Funding Incentive (IFI). Those for June and September do not include IFI.
2. For comparability, EDF - SPN is shown on the basis of X=0. Actual P0 will be 3.1%, with RPI +2.

The final proposals for revenue allowances, in comparison with the Initial Proposals and the September Update, are set out in the following table.

Final proposals for average revenue allowance 2005 -2010

DNOs	June Initial Proposals	Change	September Update	Change	November Final Proposals
	£m	£m	£m	£m	£m
CN - Midlands	227	15	241	0	242
CN - East Midlands	229	16	245	1	246
Unitied Utilities	201	19	220	4	224
CE - NEDL	140	18	159	-2	157
CE - YEDL	187	11	197	8	205
WPD-South West	170	10	180	-1	179
WPD-South Wales	136	12	148	-2	146
EDF - LPN	224	4	227	1	229
EDF - SPN	150	16	166	5	171
EDF - EPN	279	11	289	2	291
SP Distribution	284	8	292	2	294
SP Manweb	169	7	176	-1	175
SSE - Hydro	157	12	169	1	170
SSE - Southern	328	13	341	-1	340
Total	2,880	170	3,050	17	3,067

Note:
The above revenues exclude allowances for Innovation Funding Incentive (IFI).

Next steps

In parallel with these Final Proposals, Ofgem will be publishing on its website:

- a summary of responses to the September Update paper;
- an Impact Assessment for this price control;
- reports by Ofgem's consultants (PB Power) on the capital expenditure proposals of each company;
- draft licence modifications; and
- draft regulatory instructions and guidance (RIGs) for quality of service reporting, revenue reporting and distributed generation, innovation funding incentive and registered power zone reporting.

The draft licence modifications and RIGs have been discussed in detail, but not agreed, with the distribution companies. Comments on the drafting of these modifications and RIGs are requested by 17 January 2005.

Ofgem has also asked each affected distribution company to state, by 23 December 2004, whether they accept these proposals in principle.

If the companies accept the proposals in principle, Ofgem will publish a statutory consultation on the licence modifications by early February 2005. If any company rejects the proposals, Ofgem would expect to make a reference to the Competition Commission.

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1. Introduction

1.1. The existing price controls on the Distribution Network Operators (DNOs) are due to be reset with effect from 1 April 2005. The work to review these price controls began in 2002 and now culminates with these Final Proposals.

1.2. Consultation on the objectives for the price control review began in August 2002. The objectives are primarily driven by Ofgem's statutory objectives and duties, and the statutory and licence obligations of the DNOs.

1.3. Ofgem's principal objective as set out in the Electricity Act 1989 as amended by the Utilities Act 2000 and the Energy Act 2004 is to protect the interests of consumers (present and future), wherever appropriate by promoting effective competition. The Electricity Act also sets out other important duties for Ofgem[1], including:

- securing a diverse and viable long-term energy supply;
- ensuring that licence holders are able to finance their statutory and licensed obligations;
- having regard to the effect on the environment of activities connected with the generation, transmission, distribution or supply of electricity; and
- having regard to the interests of individuals who are disabled or chronically sick, of pensionable age, living on low incomes, or residing in rural areas.

1.4. Ofgem also has other statutory duties in respect of the environment, as set out in various other Acts[2]. Ofgem has regard to all of its duties when carrying out its functions.

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[1] See sections 3(A) – 3(C) of the Electricity Act 1989 as amended by the Utilities Act 2000
[2] For example, the Environment Act 1995 and the Countryside and Rights of Way Act 2000

Project update

1.5. Since the publication of the September 2004 Update document,[3] a committee of the Gas and Electricity Markets Authority has met with each of the DNO management teams at a senior level to discuss the outstanding issues on the review. For each management team, this was the third such meeting during the course of the review, reflecting Ofgem's commitment to transparency and access. In addition, Ofgem has met each company management at least once. In Ofgem's view, all of the company management teams have had ample opportunity to make their case.

1.6. In addition, since the September Update:

- an Ofgem-DNO legal issues working group has met on three occasions to discuss drafts of the licence modification proposals that will give effect to the price controls and the regulatory instructions and guidance documents that will support reporting against, monitoring and subsequent review of the licence conditions;
- an Ofgem-DNO-NGT incentives working group has met twice to discuss the development of the incentives framework;
- an Ofgem-DNO cost assessment working group has also met to discuss outstanding cost and financial issues;
- Ofgem has published a consultation on the Statutory Instrument that will give effect to the revised standards of performance;
- Ofgem has written to the companies setting out a timetable for the proposed project on cost reporting (set out in Chapter 2) and all the companies have committed to support this work;
- Ofgem has published the 2003/04 Electricity Distribution Quality of Service report, which demonstrates the relative performance of the

[3] Electricity Distribution Price Control Review, Update paper, September 2004, Ofgem ref 222/04

companies under the current quality of service incentives and sets out the resultant rewards and penalties;

- Ofgem has met with two of the main rating agencies, to discuss the financial profiles which could be required to support appropriate credit ratings; and

- Ofgem has consulted on the draft charging methodologies prepared by the companies to explain their proposed connection and use of system charging arrangements that will take effect from April 2005.

Purpose and structure of this document

1.7. This document sets out Ofgem's final proposals for the Electricity Distribution Price Control Review. It is structured as follows:

- Chapter 2 – sets out the timetable for implementation of the review and for the project to develop annual cost reporting;

- Chapter 3 – summarises the final proposals for the form, structure and scope of the price control, which are largely as set out in the March 2004 Policy document;[4]

- Chapter 4 – sets out the proposed targets and incentive arrangements for quality of service, which are unchanged from September, and associated arrangements. It also sets out the targets and incentives for electrical losses;

- Chapter 5 – sets out the proposed arrangements for distributed generation (including registered power zones) and the innovation funding incentive, which are largely as set out in March;

- Chapter 6 – provides final proposals for the separate metering control;

[4] Electricity Distribution Price Control Review, Policy document, March 2004, Ofgem ref 62/04

- Chapter 7 – sets out the cost allowances and associated incentives, most components of which remain unchanged from September;
- Chapter 8 – covers a range of financial issues, including the Regulatory Asset Value (RAV), pensions, tax and the cost of capital;
- Chapter 9 concludes with the resultant base revenue allowances and "P0" values, including price control calculations for each company;
- Appendix 1 summarises the assumptions made in conducting this review about how the RAV will be calculated in the forthcoming control period and how rolling incentive payments will be calculated at the next review;
- Appendix 2 sets out basic metering activities; and
- Appendix 3 provides detailed cost and financial tables.

1.8. To accompany this document, Ofgem will also publish:

- a summary of responses to the September update paper;
- an Impact Assessment of the price review;
- a draft of the licence modifications that would effect these proposals (and associated guidance documents), for informal consultation; and
- reports by consultants PB Power on the capital expenditure proposals of each company.

Responding to this document

1.9. The electricity distribution companies have agreed to respond to Ofgem prior to 23 December 2004 with a decision on whether they accept these proposals.

1.10. Any comments on the draft licence modifications set out in the accompanying document are requested by 17 January 2005 and should be sent to

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1.11. No other comments are specifically sought on this document.

1.12. Unless marked as confidential all responses will be published by placing them in Ofgem's library or on the website. It would be helpful if responses could be submitted both electronically and in writing. Any questions on this document should, in the first instance, be directed to Paul O'Donovan, who can be contacted on 020 79017414 or by email at Paul.ODonovan@ofgem.gov.uk

2. Timetable

2.1. The timetable for the price control review was originally set out in detail in March 2003. This timetable has been updated over the course of the review, in particular to allow more time for consultation responses than originally scheduled, but to a large extent has been met.

2.2. The timetable for remainder of the process, if these final proposals are accepted, is as set out in the table below.

Table 2.1 Timetable for remainder of the price control process

November 2004	Final Proposals Paper published (including P0/Xs and drafts of proposed Licence modifications)
December 2004	Companies indicate whether they are willing to accept the new price controls
2005	
January (or February) 2005	Statutory notice on licence modifications
April 2005	**1 April New price controls implemented**
Early Summer 2005	Publish report on the price control review process for consultation
Autumn 2005	Publish final report on the price control review process

2.3. If one or more companies reject these proposals, Ofgem would expect to make a reference to the Competition Commission, probably in January 2005. The Commission would be expected to report in the summer of 2005. The post-project review would then be delayed by approximately six months.

2.4. Ofgem has also sent to the companies a proposed timetable and process for developing improved cost reporting arrangements, on the assumption that there is no Competition Commission reference. In general, the companies have accepted this timetable, which is set out below.

Table 2.2 Timetable for the cost reporting project

30 November 2004	Ofgem circulates initial draft cost reporting guidelines to DNOs
2005	
January 2005	Discussions of draft guidelines with DNOs
Mid February 2005	**Ofgem publish draft cost reporting guidelines for general consultation**
April 2005	Ofgem publish final draft RIGs for 2004/05
July 2005	DNOs submit 2004/05 data on the basis of April 2005 guidelines as far as possible
August – October 2005	Review and discussion of 2004/05 data
November 2005	**Ofgem publish summary of 2004/05 data and proposed guidelines for 2005/06 data collection**
2006	
July 2006	DNOs submit 2005/06 data
etc	

3. Form, structure and scope of the price controls

Introduction

3.1. This chapter sets out Ofgem's final proposals on the form, structure and scope of the electricity distribution price controls to apply from April 2005.

3.2. The chapter does not restate the views expressed during consultation or the reasons for decisions in full as this has already been covered in previous consultations, particularly in the March 2004 Policy Paper and the June 2004 Initial Proposals.

Form of the price control

3.3. The July 2003 Initial Consultation[5] set out Ofgem's intention to continue with the RPI-X form of price control. It also proposed continuing with a five year price control period, while noting that increasing the period can strengthen the incentives for companies to deliver efficiency savings.

3.4. As discussed in previous documents, **Ofgem proposes to continue with the RPI-X form of price control for a period of five years, ie from 1 April 2005 to 31 March 2010**. As described in the remainder of this document, significant changes are being proposed to the regulatory framework for electricity distribution in response to the challenges facing the sector and these should, in Ofgem's view, be subject to a full review no later than implied by this five year horizon.

Price index

3.5. During the review, Ofgem has considered whether to switch from using RPI to the Harmonised Index of Consumer Prices (known in the UK as the CPI) for price control purposes. **Ofgem proposes to continue to use the RPI for this price control**.

Structure of the price control

3.6. The proposed structure of the price control comprises:

- DNO base revenue allowances linked to a revenue driver. This driver is an equally weighted function of the number of units distributed and customer numbers;
- incentive mechanisms that encourage DNOs to:
  - reduce the level of electrical losses and promote energy efficiency; and
  - improve the quality of service delivered to consumers, particularly in relation to the number and duration of interruptions to supply and the quality of telephone response provided to consumers.
- pass-through for the costs of prescribed business rates on network assets, Ofgem licence fees, transmission exit charges and other specified non-controllable costs;
- a correction mechanism that adjusts the price control for any previous over or under recovery of revenue; and
- an adjustment mechanism for specific uncertain costs.

3.7. This section summarises the proposals on the revenue driver, the pass through items, and the correction and adjustment mechanisms. Chapter 4 discusses the quality of service and losses incentive mechanisms. Cost incentives are delivered throughout the duration of the control by fixing revenue for the five

[5] Electricity Distribution Price Control Review – Initial Proposals, July 2003, Ofgem ref 68/03

year period, by use of rolling incentive arrangements and by the manner in which the control is reset (see Chapters 7 and 8).

3.8. There are separate price controls proposed for distributed generation (see Chapter 5) and metering (see Chapter 6).

Revenue driver

3.9. Ofgem proposes that the base demand revenue driver will be of the same form as in the current price control, but it has been updated so that the actual number of consumers will be used for the calculation and more appropriate weightings for the voltage categories will be applied. There will be an additional term in the revenue driver to reflect the inclusion of EHV charges, which will not have a volume related term. The weightings proposed are set out in the table below:

Table 3.1 Proposed weightings for revenue driver

	Revenue Driver			
	LV1	LV2	LV3	HV
CN - Midlands	1.0397	0.1220	0.9286	0.2503
CN - East Midlands	0.7512	0.1680	0.5537	0.1960
United Utilities	1.8789	0.2104	1.4180	0.6297
CE NEDL	1.0512	0.1100	0.8205	0.1580
CE YEDL	0.7700	0.1200	0.6025	0.1750
WPD - South West	1.8800	0.4100	1.2734	0.2350
WPD - South Wales	1.8600	0.2700	1.3852	0.2415
EDF - LPN	1.0970	0.1360	0.6988	0.2580
EDF - SPN	0.7456	0.0929	0.5076	0.2376
EDF - EPN	1.0252	0.3010	0.9072	0.2503
SP Distribution	2.3041	0.2849	1.3996	0.2150
SP Manweb	1.5005	0.2636	1.4931	0.1350
SSE - Hydro	1.8824	0.8819	1.9542	0.4900
SSE - Southern	1.2118	0.1806	1.0334	0.2842

Pass-through of costs

3.10. Ofgem proposes that the price control will pass-through:

- transmission exit charges;

- charges from other licensed distributors covered by their price controls (wheeling charges);

- variations in network business rates from the costs assumed in setting the price control (see Chapter 8);

- variations in Ofgem licence fees from the costs assumed in setting the price control (see Chapter 8);

- the benefit of any subsidy for areas with high distribution costs;[6] and

- certain company specific items such as the costs of wholesale electricity balancing on Shetland and the costs attributable to DNOs of closing down the current wholesale trading systems (Settlement Agreement for Scotland) in Scotland following BETTA go-live.

Over and under recovery of revenues

3.11. The decision paper on rebates of electricity distribution use of system charges to suppliers[7] set out Ofgem's proposals to modify the details of the arrangements for correction factors to deal with over or under recovery of revenues. The interest rate penalties that will apply to over or under recoveries are consistent with those proposals.

3.12. Ofgem proposes that the price controls for demand and for distributed generation retain separate correction factors, but that the application of penalty interest rates is based on the net revenue position, as determined by the combined effect of the two correction factors.

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[6] See the Energy Act section 184 for further details

[7] Electricity distribution rebates to suppliers – Decision document, December 2003, Ofgem ref 155/03

Scope of the price control

3.13. In considering the scope of the price control, costs associated with the following categories were considered:

- excluded services;
- non-contestable connections; and
- uncertain costs.

Excluded services

3.14. Ofgem's proposals on excluded services are:

- charges for premises which have connections at EHV which are operational prior to 31 March 2005 will be included within the scope of the price control;
- charges for any premises newly connected at EHV during the 2005-2010 price control period will be treated as excluded service revenue until 2010, at which point Ofgem would expect to include them within the price control;
- costs associated with wheeling charges incurred by a DNO will be allowed full pass-through;
- revenue associated with the wheeling of units will be included within the price control;
- revenue associated with units distributed to embedded networks will be included within the scope of the price control;
- DNOs running out of area networks will not be able to charge consumers in those areas any more than the incumbent network operator. Any revenue associated with distributing units out of area will be treated as an excluded service item;

- power factor penalty charges will be treated as excluded services where they are explicitly metered as kVAr or kVArh;
- revenue protection services will be treated as excluded services and the revenues will be outside the distribution and metering price controls; and
- no change is proposed to the following charges which are currently categorised as excluded services: top-up and standby charges, non-trading rechargeables and "other minor activities and charges".

Non-contestable connections

3.15. The price control consultations included consideration of whether consumers of non-contestable connection services needed greater protection and how competition in this sector could be promoted. Options considered were the opening up of more areas of the market to competition, providing some form of price control protection for non-contestable service charges and the introduction of guidelines on charging and/or standards of performance.

3.16. Ofgem does not propose to change the price control treatment of connections in respect of reinforcement for demand consumers for the 2005-2010 price control. However, Ofgem will continue to monitor this issue and to promote competition in connections. To this end, Ofgem proposes to require DNOs to establish and publish a clear schedule of charges regarding non-contestable services directly relating to the monopoly network.

3.17. Ofgem considers that the current voluntary standards of performance in relation to the provision of connection services should be extended to cover all new connection services, but it does not intend to attach financial penalties to these standards at this time. Further information on the standards of performance for new connections is available in another Ofgem document.[8]

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[8] Competition in connections to electricity distribution systems, Decision document – Part A, November 2004, Ofgem ref. 252/04

Uncertain costs

3.18. From the outset of the price control consultations, DNOs highlighted that there were a number of issues on which they would be exposed to unpredictable levels of costs. These costs could be divided into two categories:

- "known" items, such as the implementation of the Traffic Management Act, where DNOs have argued that it will have a significant impact on their costs, but the level of impact is difficult to quantify in advance of its implementation; and

- "unknown" items which may have a significant impact on their costs but could not reasonably have been foreseen by a competent distributor.

3.19. Ofgem considers that in this instance it is preferable to specify fixed allowances once the magnitude of costs becomes known, so that distributors would be incentivised to reduce costs. Ofgem proposes a specific re-opener for the Traffic Management Act (or Scottish equivalent) and a two-stage re-opener for changes to the Electricity Safety, Quality and Continuity Regulations (ESQCR). The ESQCR re-openers provide for an assessment in 2008 of costs associated with overhead line clearances and assessment at any time of costs associated with amendments to the ESQCR itself. These changes will be reflected in relevant licence modifications so that any consequential costs will be considered in isolation from companies' financial performance under the price control. Ofgem has also stated that it does not consider it appropriate to introduce a formalised mechanism to deal with other new obligations and costs that may arise between reviews.

4. Quality of service and other outputs

Introduction

4.1. This Chapter sets out Ofgem's final proposals for quality of service regulation for the period 2005-10. It describes Ofgem's decisions on the revenue to be exposed to the quality of service arrangements, the interruption incentives and allowances, changes to the standards of performance and the arrangements to apply in the case of exceptional events such as severe weather. It also includes the final proposals for the telephony and losses incentives.

4.2. The proposals incorporate targets for significant improvements in performance, stronger incentives to beat those targets and streamlined arrangements for compensation for prolonged outages.

Revenue exposure to quality of service incentives

4.3. Consumers value the quality and security of the service that they receive as well as the price that they pay for that service. Work on assessing consumers' priorities[9] suggests that they are willing to pay more for improved service – but only up to a certain point. Table 4.1 sets out Ofgem's decision on the amount of revenue to expose to quality of service which has been informed by the survey results. There are some 'new' areas where Ofgem proposes that DNOs will be incentivised – the details of these mechanisms are explained below.

[9] Electricity Distribution Price Control Review Appendix, Consumer Expectations of DNOs and WTP for Improvements in Service report, June 2004, Ofgem ref. 145f/04

Table 4.1 Revenue exposure to quality of service

Incentive arrangement	Current	Proposal
Interruption incentive scheme	+2% to -1.75%	+/- 3%
Storm compensation arrangements	- 1%	- 2%
Other standards of performance	Uncapped	Uncapped
Quality of telephone response	+/- 0.125%	+0.05% to –0.25%
Quality of telephone response in storm conditions	Not applicable	0 initially +/-0.25% for 3 yrs
Discretionary reward scheme	Not applicable	Up to +£1m
Overall cap/total[10]	+2% to – 2.875%	4% on downside No overall cap on upside

Interruption incentive scheme

4.4. As part of the price control review Ofgem has consulted on the approach to the interruption incentive scheme, including the form of the scheme, targets and associated costs. Ofgem's final proposals for the scheme incorporate targets for significant improvements in performance and stronger incentives to beat those targets.

Form of the incentive scheme including the weighting of planned interruptions

4.5. The interruptions incentive scheme will have symmetric annual rewards and penalties depending on each DNO's performance against their targets for the number of customers interrupted per 100 customers (CI) and the number of customer minutes lost per customer (CML). The proportion of revenue exposed under the scheme will be 1.2 per cent for CI and 1.8 per cent for CML respectively.

4.6. The weighting of each source of CI and CML in the incentive scheme is set out in Table 4.2 below.

[10] Excluding other standards of performance and the discretionary reward.

Table 4.2 Interruptions included in the incentive scheme

Source of CI/CML	Weighting
Unplanned CI & CML arising on the distribution network	100% for CI and CML
Pre-arranged CI & CML arising on the distribution network	50% for CI and CML
CI & CML arising from distributed generators	100% weighting for CI and CML
CI & CML arising from transmission and other connected networks	0% weighting for CI 10% weighting for CML

Targets for CI and CML

4.7. The proposed final targets for each DNO in respect of CI and CML for the period 2005 to 2010 (all shown with 50 per cent weighting on planned interruptions) are set out in the tables below.

Table 4.3 Targets for Customer Interruptions (CIs)

	Actuals				Target				
	2001/02	2002/03	2003/04		2005/06	2006/07	2007/08	2008/09	2009/10
CN - Midlands	120.1	99.8	113.1		109.4	107.8	106.2	104.6	103.0
CN - East Midlands	77.0	74.7	83.4		77.9	77.5	77.1	76.7	76.3
United Utilities	55.5	65.7	50.3		57.2	57.1	57.1	57.1	57.1
CE - NEDL	82.2	76.5	64.9		74.5	74.5	74.5	74.5	74.5
CE - YEDL	77.4	62.8	66.0		68.7	68.6	68.5	68.5	68.4
WPD - South West	100.7	81.8	71.0		84.5	84.5	84.5	84.5	84.5
WPD - South Wales	112.7	96.0	94.7		99.7	98.2	96.8	95.3	93.9
EDF - LPN	38.0	35.8	34.7		36.2	36.2	36.2	36.2	36.2
EDF - SPN	93.0	88.4	96.1		90.5	88.5	86.5	84.5	82.5
EDF - EPN	101.0	84.7	89.6		90.3	88.8	87.2	85.7	84.2
SP Distribution	59.0	63.4	60.2		60.9	60.8	60.8	60.8	60.8
SP Manweb	46.1	41.0	49.2		46.7	46.7	46.7	46.7	46.7
SSE - Hydro	115.4	90.0	84.1		96.2	95.8	95.5	95.2	94.9
SSE - Southern	98.3	91.5	86.1		91.0	90.1	89.2	88.3	87.4
Average	83.1	75.0	75.3		77.1	76.5	75.8	75.1	74.5

Table 4.4 Targets for Customer Minutes Lost (CMLs)

	Actuals				Target				
	2001/02	2002/03	2003/04		2005/06	2006/07	2007/08	2008/09	2009/10
CN - Midlands	116.9	100.9	100.3		102.3	98.5	94.7	91.0	87.2
CN - East Midlands	87.0	78.5	84.8		80.1	76.7	73.4	70.0	66.7
United Utilities	61.7	65.6	57.4		59.8	58.1	56.4	54.7	53.0
CE - NEDL	83.9	67.7	65.8		71.4	70.4	69.4	68.4	67.4
CE - YEDL	72.6	66.2	71.8		68.5	66.8	65.1	63.4	61.7
WPD - South West	78.6	57.9	50.2		62.2	62.2	62.2	62.2	62.2
WPD - South Wales	83.3	69.5	63.8		72.2	72.2	72.2	72.2	72.2
EDF - LPN	40.8	41.7	38.2		40.2	40.1	40.1	40.1	40.0
EDF - SPN	93.3	77.4	86.7		81.4	77.0	72.6	68.2	63.8
EDF - EPN	77.5	74.6	73.4		73.7	72.2	70.6	69.1	67.6
SP Distribution	61.8	70.3	73.4		64.9	61.2	57.6	54.0	50.4
SP Manweb	50.2	49.9	61.0		51.8	49.9	48.0	46.1	44.2
SSE - Hydro	135.6	79.6	75.6		95.9	94.9	93.9	93.0	92.0
SSE - Southern	95.8	78.8	76.2		82.0	80.5	78.9	77.4	75.8
Average	79.7	70.8	71.1		71.8	69.8	67.8	65.8	63.8

4.8. As explained in the Initial Proposals, the CML target setting methodology sets targets for two licensees at the level of their actual performance, which is more challenging than the 2020 benchmarks imply (the tables above show the proposed targets rather than the benchmarks). For consistency, these DNOs receive an additional allowance which, using the updated information now available, amounts to £1.52m for WPD-South West and £0.42m for WPD – South Wales (per annum, in 2002/03 prices).

Incentive rates

4.9. Tables 4.5 and 4.6 set out the final incentive rates for the period 2005 to 2010.

Table 4.5 CI incentive rates

Incentive rates for the number of customers interrupted per 100 customers (£m/CI – 02/03 prices)						
DNO	2005/6	2006/7	2007/8	2008/9	2009/10	2004/5 IIP incentive rate
CN - Midlands	0.10	0.11	0.11	0.11	0.11	0.06
CN - East Midlands	0.15	0.15	0.15	0.15	0.16	0.09
United Utilities	0.18	0.18	0.18	0.19	0.19	0.13
CE – NEDL	0.10	0.10	0.10	0.10	0.10	0.06
CE – YEDL	0.13	0.14	0.14	0.14	0.14	0.08
WPD - South West	0.10	0.10	0.10	0.10	0.11	0.07
WPD - South Wales	0.07	0.07	0.07	0.08	0.08	0.03
EDF – LPN	0.29	0.30	0.30	0.31	0.31	0.24
EDF – SPN	0.09	0.09	0.09	0.10	0.10	0.05
EDF – EPN	0.15	0.15	0.16	0.16	0.17	0.10
SP Distribution	0.23	0.23	0.23	0.23	0.23	0.13
SP Manweb	0.18	0.18	0.18	0.18	0.18	0.11
SSE - Hydro	0.08	0.08	0.08	0.09	0.09	0.04
SSE - Southern	0.18	0.18	0.18	0.19	0.19	0.11
Average	0.15	0.15	0.15	0.15	0.15	0.10

Table 4.6 CML incentive rates

Incentive rate for the number of customer minutes lost per customer (£m/CML)						
DNO	2005/6	2006/7	2007/8	2008/9	2009/10	2004/5 IIP incentive rate
CN - Midlands	0.14	0.15	0.15	0.16	0.17	0.10
CN - East Midlands	0.18	0.19	0.20	0.21	0.23	0.17
United Utilities	0.22	0.23	0.23	0.24	0.25	0.16
CE – NEDL	0.13	0.13	0.14	0.14	0.14	0.08
CE – YEDL	0.17	0.18	0.18	0.19	0.20	0.16
WPD - South West	0.17	0.17	0.17	0.18	0.18	0.13
WPD - South Wales	0.12	0.12	0.12	0.12	0.13	0.05
EDF – LPN	0.33	0.33	0.34	0.35	0.35	0.25
EDF – SPN	0.12	0.13	0.14	0.15	0.16	0.09
EDF – EPN	0.23	0.24	0.25	0.25	0.26	0.17
SP Distribution	0.27	0.28	0.30	0.33	0.35	0.14
SP Manweb	0.20	0.21	0.22	0.23	0.24	0.12
SSE – Hydro	0.10	0.11	0.11	0.11	0.11	0.04
SSE - Southern	0.24	0.25	0.26	0.27	0.28	0.15
Average	0.19	0.19	0.20	0.21	0.22	0.13

4.10. The calculation of rewards and penalties will be based on the targets and incentive rates set out here, along with actual performance (after any appropriate adjustments for accuracy and exceptional events and rounded to one decimal place). So if, for example, CN – Midlands actual CML performance in 2005/06 was 99.862, its reward would be (102.3 – 99.9) x 0.14 = £0.336m.

Cost allowances

4.11. All DNOs that have been set targeted improvements in the number of interruptions experienced by customers have been given associated capital expenditure allowances based on an assessment of the marginal costs of improvement. Where DNOs are required to maintain the current average number of interruptions experienced by customers there is no associated capital expenditure allowance.

4.12. Ofgem has also included a cost allowance for improvements in restoration times. This allowance is based on a specified amount per fault (of approximately £330) multiplied by their weighted number of faults.

4.13. The cost allowances associated with the target improvements in performance are set out in Table 4.7 below. They are totals for the five year price control period.

4.14. Where the restoration cost allowance is used to fund capital expenditure, this expenditure will be included as part of the capex incentive mechanism.

Table 4.7 Interruption cost allowances

QOS allowances	Capex (5 yrs) – Final proposals	Restoration costs (5 years) – Final proposals
	£m (02/03 prices)	£m (02/03 prices)
CN - Midlands	24.0	9.2
CN - East Midlands	8.9	10.6
United Utilities	0.0	8.9
CE – NEDL	0.0	6.1
CE - YEDL	3.9	8.4
WPD - South West	0.0	8.1
WPD - South Wales	6.2	5.5
EDF - LPN	0.0	3.8
EDF - SPN	21.1	7.2
EDF - EPN	22.5	12.0
SP Distribution	0.0	8.5
SP Manweb	0.0	7.9
SSE – Hydro	0.0	5.2
SSE – Southern	25.0	12.1
Total	111.6	113.5

Severe weather exceptional events

4.15. The impact of severe weather events will be fully excluded from the incentive scheme. Severe weather events are defined as weather events which cause 8 or more times the daily mean number of faults at higher voltage[11] in a 24-hour period.

4.16. Ofgem is strengthening the incentives on DNOs to restore customers' supplies promptly and efficiently following severe weather events (as explained in the section on supply restoration standards below) and as a result Ofgem is providing an annual cost allowance for exceptional events to cover an efficient level of compensation payments and fault costs relating to these events. The allowance has been derived by calculating an allowance per exposed customer for medium-sized and major events and multiplying this by the number of exposed customers and the frequency of occurrence of the events. An allowance for 1 in 20 year events has then been added to derive the final allowance for each DNO.

4.17. The exceptional event allowances for each DNO are set out in Table 4.8. They are annual allowances and are unchanged from the September update paper. DNOs are free to use this allowance either to reduce the chance of such events occurring, to manage the impact of the events through faster customer restoration or to buy storm insurance cover.

Table 4.8 Allowance for exceptional events

DNO	Allowance per exposed customer for medium events		Allowance per exposed customer for major events		Allowance for 1 in 20 year events	Number of exposed customers	Annual allowance for exceptional events (£m)
	Lightning	8 times to 13 times	13 times to 20 times	20 +			
	£ 0.12	£ 0.33	£ 1.22	£ 2.87			
	Number of events per year						
CN - Midlands	0.6	0.8	0.3	0.4	0.46	990,000	2.3
CN - East Midlands	1.0	1.0	0.2	0.3	0.45	1,170,000	2.3
United Utilities	0.4	0.5	0.1	0.3	0.40	750,000	1.3
CE - NEDL	2.3	0.7	0.3	0.6	0.29	620,000	1.9
CE - YEDL	0.6	0.9	0.2	0.2	0.41	990,000	1.6
WPD - South West	1.9	0.7	0.0	0.4	0.32	770,000	1.6
WPD - South Wales	0.6	0.9	0.2	0.8	0.24	590,000	2.0
EDF - LPN	na	na	na	na	na	na	na
EDF - SPN	0.4	0.6	0.1	0.2	0.29	810,000	1.1
EDF - EPN	0.3	1.5	0.5	0.3	0.55	1,380,000	3.3
SP Distribution	0.3	0.7	0.3	0.5	0.51	650,000	1.8
SP Manweb	1.0	0.9	0.1	0.4	0.31	540,000	1.2
SSE - Hydro	0.7	1.8	1.2	0.4	0.30	340,000	1.4
SSE - Southern	0.0	0.7	0.1	0.5	0.57	1,190,000	2.7

4.18. As EDF-LPN's network is almost entirely underground, it is not exposed to the impact of severe weather events in the same way as other DNOs so does not receive a cost allowance for them.

One-off exceptional events

4.19. Although significant numbers of exceptional events are caused by severe weather conditions there are also "one-off" exceptional events due to causes such as transmission faults and third-party damage.

[11] Higher voltage means any nominal voltage of more than 1,000 volts up to and including 132 kilovolts in England and Wales and up to but excluding 132 kilovolts in Scotland.

4.20. Adjustments to performance will only be considered for those events outside the DNO's control caused by a third-party, act of God or which are outside the normal experience of the DNO.[12] For example, these would include:

- a fault on a transmission or other connected network;
- third party damage such as vandalism or terrorism;
- damage from birds and animals where this could not reasonably have been prevented; and
- other longer-running events such as restricted access due to foot and mouth disease control restrictions.

4.21. Events such as failure of protection equipment or fires resulting from failure of a DNO's own equipment would not be considered.

4.22. The thresholds for exceptionality for these types of event are 25,000 customers affected and 2 million customer minutes lost. The thresholds have been converted into CI and CML for each DNO using 2003/4 customer numbers and are set out in Table 4.9 below.

[12] Where planned work is being carried out on a circuit and there are appropriate levels of contingency in place to ensure security of supply in line with the principles of Engineering Recommendation P2/5, additional incidents outside the DNO's control which are caused by a third-party, act of God or which are outside the DNO's normal experience, which cause interruptions to supply would be considered under the exceptionality scheme if they breach the relevant thresholds.

Table 4.9 Thresholds for one-off events

DNO	Threshold of absolute customer interruptions	Converted into CI using 2003/4 customer numbers	Threshold of absolute customer minutes lost	CML threshold
CN West	25,000	1.1	2,000,000	0.9
CN East	25,000	1.0	2,000,000	0.8
United Utilities	25,000	1.1	2,000,000	0.9
CE - NEDL	25,000	1.6	2,000,000	1.3
CE - YEDL	25,000	1.2	2,000,000	0.9
WPD - South West	25,000	1.7	2,000,000	1.4
WPD - South Wales	25,000	2.3	2,000,000	1.9
EDF - LPN	25,000	1.1	2,000,000	0.9
EDF - SPN	25,000	1.2	2,000,000	0.9
EDF - EPN	25,000	0.7	2,000,000	0.6
SP Distribution	25,000	1.3	2,000,000	1.0
SP Manweb	25,000	1.7	2,000,000	1.4
SSE - Hydro	25,000	3.7	2,000,000	2.9
SSE - Southern	25,000	0.9	2,000,000	0.7
Average	25,000	1.25	2,000,000	1.0

4.23. Any CI and CML above these thresholds[13] will be removed from performance in the annual quality of service incentive scheme, provided the DNO can show that it has taken all appropriate steps to prevent the event and to mitigate the impact.

4.24. In the case of longer duration events DNOs would need to track the additional CI and CML resulting from the event for its entire duration. For every 3 month period, the CI and CML attributed to the event would be measured against the thresholds and performance in excess of the thresholds would be excluded from the incentive scheme, provided the DNO can show that it has taken all appropriate mitigating actions before, during and after the event.

Interruption audits

4.25. The audit process for the coming price control period will involve the following stages:

- **Audit preparation** – At the end of each reporting year, DNOs will be required to submit information on CI and CML at each voltage both by incident and restoration stage. Ofgem will then select a sample of 150 incidents, split between HV and above and LV according to the respective contribution to CI and CML (with a minimum of 50 LV incidents). Most or all of the sample will be notified to the DNOs in advance, however, a small part of the sample may be held back until the time of the audit.

- **Audits (Stage1**) – Ofgem's audit consultants will be required to assess the accuracy of the DNOs' measurement systems by considering:

  - the accuracy of the Meter Point Administration Number (MPAN) count that has been used for the connectivity model;

  - the underlying assumptions that the DNOs have used to link customer information to their network models;

  - whether the DNOs have correctly applied the Regulatory Instructions and Guidance (RIGs) definitions; and

  - whether Ofgem's reporting template has been correctly populated.

- **Audits (Stage 2) –** The audit consultant will audit 50 HV and above incidents and 30 LV incidents, and then calculate combined LV and overall accuracies for both CI and CML[14]. If the DNO meets accuracy thresholds of 92 per cent at LV and 97 per cent overall then the audit will be complete and no adjustment would be made to the DNO's performance figures;

- **Audits (Stage 3) –** Where the DNO fails to meet the LV or overall accuracy thresholds in stage 2, the process will continue until all

[13] For incidents on transmission or other connected networks the 0 per cent weighting for CI and 10 per cent weighting on CML will be applied before testing for exceptionality.
[14] The combined accuracies will be calculated by multiplying the MPAN accuracies with the accuracy of incident reporting as set out in version 5 of the RIGs.

incidents in the LV sample have been audited. The combined LV accuracy will then be recalculated. At this point if the DNO fails to meet the 90 per cent accuracy target set out in the RIGs then the appropriate adjustment(s) will be made to annual performance to bring its data to 100 per cent of the estimated accurate level.

Similarly, where DNOs fail to meet the overall accuracy thresholds in stage 2 the process will continue until all incidents in the overall sample have been audited. The combined overall accuracy results will then be recalculated. At this point if the DNO fails to meet the 95 per cent accuracy target set out in the RIGs then the appropriate adjustment(s) would be made to annual performance to bring its data to 100 per cent of the estimated accurate level.

4.26. Further details are set out in Appendix 5 of the Quality of Service RIGs.

Frontier performance for this price control period

4.27. Ofgem's analysis comparing average actual performance for the last three years with benchmarks based on 2002/3 and 2003/4 performance shows SP Manweb, EDF - LPN, SSE Hydro and United Utilities to be the top 4 performers on CI. These DNOs will be entitled to take part in the CI element of the 2004/5 out-performance scheme regardless of whether or not they have met both their CI and CML targets. The analysis shows WPD South Wales, WPD South West, EDF - EPN and SSE Southern to be the top 4 performers on CML per CI. These DNOs will be eligible to take part in the CML element of the 2004/05 out-performance scheme regardless of whether they have met both their targets for CI and CML.

Treatment of planned interruptions for the final year of this price control period

4.28. In the March consultation paper, Ofgem proposed that DNOs should be allowed to roll forward up to 2 planned CIs and 3 planned CMLs from 2004/5 to 2005/6, provided that they made a commitment to do so before 30 April 2004. Only CE - YEDL has elected to take advantage of this mechanism. CE - YEDL has committed to 3 planned CML being rolled forwards to 2005/6 with an 'interest rate' of 6.5 per cent.

Standards of Performance

4.29. As part of this price control review Ofgem has consulted on range of improvements to the existing Standards of Performance arrangements. Ofgem's final proposals for the changes to the standards strengthen the incentives for DNOs to restore customers promptly and efficiently following severe weather events and streamline the arrangements for compensation for prolonged outages.

Standard of Performance for supply restoration

Normal and Severe Weather Standards

4.30. There will be separate Standards for supply restoration under "normal weather" conditions and severe weather set out in a new Statutory Instrument.

4.31. Under normal weather conditions domestic customers will be entitled to £50 compensation (non-domestic £100) after being off supply for 18 hours, with a further £25 for each subsequent 12 hour period. The level of compensation will continue to be uncapped.

4.32. Under severe weather conditions the trigger period for payment (i.e. the time at which customers are entitled to compensation) will depend on the scale of event. This is summarised in Table 4.10 below.[15]

[15] Severe weather events on an IDNO's network will be categorised in the same way as for the DNO in whose distribution services area it operates.

Table 4.10 Severe weather banding

Category of severe weather	Definition	Trigger period for compensation
Category 1 (medium events)	Lightning events (≥8 times daily mean faults at higher voltage and less than 35% of exposed customers[16] affected)	24 hours
	Non-lightning events (≥8 and < 13 times daily mean faults at higher voltage and less than 35% of exposed customers affected)	
Category 2 (large events)	Non-lightning events (≥13 times daily mean faults at higher voltage and less than 35% of exposed customers affected)	48 hours
Category 3 (very large events)	Any severe weather events where ≥ 35% of exposed customers are affected	$48 \text{ hours} \times \left(\frac{\text{Number of customers affected}}{35\% \text{ of exposed customers}} \right)^2$

4.33. Both domestic and non-domestic customers will be entitled to £25 compensation after the trigger period has passed (e.g. after 24 hours following a category 1 event, 48 hours for a category 2 event and a period based on a square-law relationship for category 3 events) and a further £25 for each additional period of 12 hours up to a cap of £200. The thresholds for each of the severe weather categories are set out in Table 4.11 below.

[16] Exposed customers are defined as customers on mixed or overhead circuits (i.e. those customers that may be affected by a severe weather event.) In the case of EDF - LPN a different approach has been used to calculate the threshold as its circuits are almost entirely underground. Ofgem has calculated 35 per cent of exposed customers as a percentage of total customers for all other DNOs and then applied this figure to EDF - LPN's total number of customers to arrive at the threshold.

Table 4.11 Thresholds for normal and severe weather conditions

	Category 1 - Medium severe weather events	Category 2 - Large severe weather events	Category 3 - Very large severe weather events
DNO	**8*mean HV and above**	**13*mean HV and above**	**35% of exposed customers**
CN-Midlands	63	103	348,000
CN-East Midlands	58	95	410,000
United Utilities	47	77	262,000
CE – NEDL	36	59	218,000
CE – YEDL	35	57	347,000
WPD – South West	54	88	270,000
WPD – South Wales	46	75	208,000
EDF - LPN	10	17	331,000
EDF – SPN	46	74	284,000
EDF – EPN	72	117	484,000
SP Distribution	79	129	226,000
SP Manweb	61	99	188,000
SSE – Hydro	61	99	119,000
SSE - Southern	62	101	417,000

4.34. DNOs' exposure to the severe weather arrangements is capped at 2 per cent of base price control revenue per annum. There is no cost pass-through up to this level. There will be full cost pass-through of any payments that are made beyond this level.

Snow, ice accretion and flooding

4.35. Under all weather conditions there will be a delay in the clock starting to count towards the trigger period for compensation if snow, flooding or ice accretion directly prevents the DNO from carrying out work necessary to restore the customer's supply.

Exemptions

4.36. All DNOs affected by a category 3 (very large) severe weather event will be exempt from paying customers compensation for that event if any of those DNOs have more than 60 per cent of exposed customers off supply.

4.37. In addition the existing "non-weather" exemptions will continue to apply.

Treatment of the Highlands and Islands

4.38. The existing 18 hour Guaranteed Standard for supply restoration (GS2) will continue to apply to the Highlands and Islands of Scotland. SSE - Hydro will be entitled to claim an exemption from paying compensation for severe weather but customers will be able to apply for a determination if they feel that compensation had been withheld unreasonably.

Incentives to pay compensation under the normal and severe weather standards

4.39. DNOs currently have an incentive to avoid making customers aware that they are entitled to a payment for a failure to reduce their financial exposure to the Standards. Ofgem has decided that this incentive should be removed by ensuring that the penalty to DNOs, where there is a failure under the normal or severe weather arrangements, or the Highlands and Islands standard, is the same, whether or not the customer claims. Where a DNO does not pay the customer, it will face an equivalent reduction in its price control revenue.

4.40. DNOs should make reasonable endeavours to pay out automatically under the standards where possible and should be more proactive in contacting affected customers to make them aware of their right to compensation.

Extension of the Guaranteed Standards to DNOs operating out of area and Independent Distribution Network Operators (IDNOs)

4.41. Ofgem has proposed that all of the distribution Guaranteed Standards (including the new Severe Weather Standard) should be extended both to DNOs operating out of area and IDNOs. For most of the Guaranteed Standards (e.g. making and keeping appointments and providing estimates for connections) the extension to other distributors is relatively straightforward. However it raises a number of boundary issues for the standards relating to supply interruptions. For example, an 18 hour interruption may arise due to faults on another network or several networks.

4.42. Under **the Normal, Severe Weather and Highlands and Islands standards** the distributor to whose network the customer is directly connected will be responsible for making payments to that customer for any failure under the Standards. However, the distributor will be able to claim an exemption if the interruption would not have occurred but for the failure of another distributor's system. Where the distributor wishes to claim an exemption on this basis, it has to notify the other distributor which then becomes liable for any payment unless it disputes that the interruption was caused by a failure on its network or claims another exemption under the Standards. Any dispute between distributors, including those relating to which distributor is liable to pay out, may be determined by Ofgem.

4.43. Under the **Multiple Interruption Standard,** the distributor to whose network the customer is directly connected will be responsible for making payments to the customer for any failure.

4.44. There will be a requirement in Standard Licence Condition 20 of the distribution licence for all connection and use of system agreements between distributors to contain provisions so that distributors who are liable to make payments under the restoration Standards are able to claim from other distributors for all or part of those payments made, plus financing expenses (where the payments have already been made to the customer) where the failure to meet the Standard is fully or partially the result of a failure by that distributor.

4.45. Under the severe weather restoration Standards, distributors will be required to make payments for failure under the Standard as soon as reasonably practicable having due regard to their licence obligations.

4.46. There are two possible scenarios under the **Planned Interruption Standard:**

- **Scenario A -** where a distributor needs to carry out planned work that only affects customers on its network. In this case the status quo applies. Distributors should inform their customers at least 2 days in advance of the work taking place.

- **Scenario B -** where a distributor needs to carry out planned work that affects customers connected to another distribution network. In this case Ofgem proposes that the distributor carrying out the work should inform the other distributor 10 days before the work takes place and then that distributor in turn will need to inform its customers at least 2 days in advance of the work taking place.

4.47. There will also be some consequential amendments to the Standard for making payments to a customer. Where a failure by one distributor affects customers connected to another network, the distributor will be required to pass on payments to the other operator, who will in turn be required to pass on the payment to its customers (either directly or via suppliers).

Other distribution Guaranteed Standards of Performance

4.48. The other Guaranteed Standards of Performance will remain unchanged apart from their scope being extended to DNOs operating out of area and IDNOs.

Route for payments to customers

4.49. Electricity distributors will have the option of making payments directly to customers or making payments via suppliers where this is not practicable. This will also bring the arrangements in electricity distribution in line with those for gas distribution.

Overall Standards of Performance

4.50. Ofgem has decided to revoke the Overall Standards of Performance for distributors but retain some of the key reporting requirements as part of the RIGs framework. If reported performance shows notable deterioration, Ofgem will investigate and may re-introduce Overall Standards.

Practice and procedure

4.51. Ofgem will include a new schedule as part of the new Standards of Performance Statutory Instrument that sets out a more comprehensive practice and procedure for both individual and consolidated disputes. This will include the deadlines for determining disputes and the key stages of the disputes process.

4.52. The new disputes practice and procedure is intended to apply to all disputes relating to the electricity standards of performance including disputes between customers and distributors, customers and suppliers and between authorised electricity operators.

Telephony Incentives

4.53. As part of the price control review Ofgem has consulted on the appropriate form of the incentive arrangements for the quality and speed of telephone response. This section set out Ofgem's final proposals for the telephony incentives.

Main telephony incentives

4.54. Ofgem will continue to provide financial incentives on the DNOs' telephony performance based on the results of an ongoing customer survey. Ofgem will retain the existing assessed attributes for survey, with the addition of a question on customer satisfaction with the speed of telephone response. Performance on this attribute has been measured on a trial basis since April 2004 and the results are similar to other assessed attributes.

4.55. The survey measures customer satisfaction on a scale of 1 to 5. DNOs will be subject to a sliding-scale penalty if their annual mean performance deteriorates below 4.1. If their annual mean scores fall below 3.6, DNOs will be liable for the full penalty of 0.25 per cent of revenue. There will be a small reward of 0.05 per cent of revenue for those DNOs with annual mean scores greater than 4.5.

4.56. Ofgem intends to publish DNOs' performance under the customer survey on a regular basis on its website and in the Quality of Service Report and may carry out spot checks on the way in which DNOs provide customer information to the survey consultants.

4.57. At present, the sample for the survey is taken from a list of customers that have spoken to a person at the call centre. This is less than ideal, as the DNOs make extensive use of automated messaging. Ofgem will therefore continue to work with the DNOs over the period up to 2007 to determine whether it will be practicable to include satisfaction with automated messaging within the telephony survey from April 2007, including whether it is possible to overcome technical hurdles.[17]

Telephony incentives in storm conditions

4.58. The incentive scheme set out above assesses DNOs' average quality of telephone response throughout the year. Following the October 2002 storms and other storm events, DNOs have been criticised for poor communication with their customers. In light of this, Ofgem intends to develop a way of supplementing the annual incentive with an incentive relating to performance during exceptional events. This will be achieved by increasing the survey sample following exceptional events so that it becomes robust over a shorter period (e.g. one week). No revenue will be exposed in the first two years of the scheme as target levels of performance will need to be established based on performance during those years. Ofgem proposes that, provided an appropriate scheme can be developed, there should be equal rewards and penalties from April 2007 with 0.25 per cent of revenue exposed.

Undergrounding in Areas of Outstanding Natural Beauty

4.59. Ofgem has reviewed the approach to network undergrounding in National Parks and Areas of Outstanding Natural Beauty since the publication of the September update paper. Under the Electricity Act 1989 (as amended) Ofgem has a duty to have regard to the impact of distribution activities on the environment. It is also required to carry out its duties in such a manner as to contribute to the achievement of sustainable development. Ofgem also has duties under the National Parks and Access to the Countryside Act 1949 (as amended by the Environment Act 1995) and the Countryside and Rights of Way Act 2000 to have regard to the purpose of conserving and enhancing the natural beauty of national

[17] Technical constraints mean that this is not possible from April 2005.

parks and areas of outstanding natural beauty. There is some evidence that customers value visual amenity and are willing to pay for improvements through their electricity bills. However, this is limited and Ofgem does not consider that consumers should pay for more than modest network undergrounding in these areas.

4.60. Ofgem has decided that DNOs should be allowed to log up actual capital expenditure on network undergrounding in these areas up to a maximum value of £350k per km for EHV and 132k lines, £85k per km for HV lines and £65k per km for LV lines with an overall cap on expenditure across the price control period set out in Table 4.12 below. (The cap equates to undergrounding 1.5 per cent of the network that is in national parks and areas of outstanding natural beauty in each DNO's area at an average cost of £100k per km.) This capital expenditure is in addition to the total capital expenditure allowance shown in Chapter 7 and Appendix 3. The DNOs will need to demonstrate that this expenditure is made in National Parks or Areas of Outstanding Natural Beauty and was additional to normal load and non-load related replacement capital expenditure. These amounts will be excluded from the capex incentive calculations described in Appendix 1.

4.61. The capital expenditure will be included in the RAV at the next price control review, together with an adjustment for the cost of capital used in at this review as the expenditure will have been incurred in advance.

4.62. Entitlement to log up costs will be subject to the DNO demonstrating that it has taken account of advice from local environmental groups and/or planning bodies in deciding how best to prioritise any expenditure on network undergrounding.

Table 4.12 Capital expenditure for network undergrounding

DNO	Total km of overhead lines in national parks and AONB	1.5 per cent of overhead lines in national parks and AONB	Max capex over 2005-10 for undergrounding £m
CN Midlands	4,178	63	£6.3
CN East Midlands	1,313	20	£2.0
United Utilities	3,317	50	£5.0
CE - NEDL	3,692	55	£5.5
CE - YEDL	734	11	£1.1
WPD - South West	9,068	136	£13.6
WPD - South Wales	3,283	49	£4.9
EDF - SPN	5,130	77	£7.7
EDF - EPN	1,910	29	£2.9
SP Distribution	553	8	£0.8
SP Manweb	3,626	54	£5.4
SSE - Hydro	3,117	47	£4.7
SSE - Southern	2,766	41	£4.1

4.63. There is no logging up mechanism for EDF-LPN as its network is almost entirely underground.

Discretionary reward

4.64. Ofgem also proposes to introduce a discretionary reward scheme to encourage best practice in areas that cannot easily be measured or incentivised through more mechanistic incentives. It will cover the following three broad categories: priority customer care initiatives; initiatives relating to corporate social responsibility (e.g. activities with schools such as promoting safety awareness); and wider communication strategies implemented by DNOs (e.g. relationships with local health authorities or with other utilities in co-ordinating work).

4.65. Performance will be assessed using a two-part annual survey; one part will request information from the DNOs on current practices and the other will be focused on key stakeholders such as social services, energywatch and other agencies.

4.66. The questionnaire returns will be reviewed by a multi-disciplinary panel, drawn from energywatch, Ofgem and, potentially, other agencies as appropriate. Ofgem would intend to appoint the panel in the coming year so that they can assist in the development of the survey.

4.67. The scheme will reward good practice, but there is no intention to penalise DNOs. The total amount of reward available will be £1 million per annum in total (across all DNOs).

Reporting requirements

4.68. As part of the price control review Ofgem has consulted on improvements to the quality of service reporting arrangements. This section set out Ofgem's final proposals for the reporting arrangements. Further details are set out in the Quality of Service RIGs.

Interruptions reporting

4.69. In the next price control period DNOs will be required to report CI and CML disaggregated by:

- duration band (including and excluding re-interruptions); and
- frequency of interruption.

4.70. Ofgem has refined the requirements for reporting CI and CML disaggregated by source, voltage level and Main Equipment Involved (MEI). It has also formalised the requirements for reporting CI and CML by HV circuit and by incident and restoration stage for each voltage level.

Speed of telephone response

4.71. Ofgem has reviewed the requirements for reporting the speed of telephone response. In light of the inclusion of the additional question in the monthly consumer survey, Ofgem has decided that it is appropriate to simplify the reporting requirements in this area. Further details are set out in the Quality of Service RIGs.

Connections

4.72. Given the proposed revocation of the Overall Standards of Performance, Ofgem has transferred the existing reporting requirements for the percentage of domestic (non-domestic) connections provided within 30 (40) working days to the RIGs.

Environmental reporting

4.73. DNOs will be required to report the following measures:

Table 4.13 Environmental reporting measures

Performance indicator	Reportable measures
Loss of sulphur hexafluoride (SF_6)	Weight of SF_6 in service (kg) Weight of SF_6 lost (ie, used for top-ups) (kg)
Loss of insulating fluid	Volume of fluid used to top-up cables (l) Total length of fluid-filled cable (km of cable)
General Environmental Management	Percentage of activities covered by a certified Environmental Management System scheme

4.74. In addition DNOs will be required to provide a supporting narrative including:

- for 2006/07 onwards, discussion of any emerging trends in the environmental data and areas of trade-off in performance;
- further details of any reportable incidents or prosecutions; and
- details of any Environmental Management Scheme accredited under ISO or other recognised accreditation scheme.

Medium-term performance reporting

4.75. Ofgem has refined the approach to medium-term performance reporting based on experience from the price control review and comments from the DNOs as set out in the revised draft of the RIGs.

Electrical losses

4.76. Over the course of the price control, Ofgem has consulted on the following issues with respect to distribution losses:

- the definition of reported losses;
- the mechanism for setting losses targets;
- the incentive retention mechanism;
- the losses incentive rate;
- whether there needs to be transitional arrangements to cover the change from one set of incentives to the other;
- the impact of distributed generation on losses targets; and
- the qualification criteria by which losses reducing capex will be allowed in the RAV.

4.77. Ofgem's proposals on the losses incentive are:

- reported losses should simply reflect the difference between the estimated volume of electricity entering and exiting the system;
- the losses target will be fixed for the five years of the price control. The proposed targets are shown in Table 4.14

Table 4.14 Losses targets

DNO	Losses Target (%)
CN – Midlands	4.96
CN - East Midlands	5.69
United Utilities	5.68
CE – NEDL	5.20
CE – YEDL	5.90
WPD - South West	6.96
WPD - South Wales	4.94
EDF – LPN	6.54
EDF – SPN	6.54
EDF – EPN	6.32
SP Distribution	6.45
SP Manweb	7.52
SSE – Hydro	8.73
SSE - Southern	6.74

These targets are as set out in the September Update with the exception of the target for Scottish Hydro-Electric, which has been modified to reflect a particular difference in the treatment of shared unmetered connections and trends in own consumption.

- DNOs keep the benefit of losses reductions for five years through the application of a rolling retention mechanism (see Appendix 1);
- the losses incentive rate will be £48/MWh (in 2004/05 prices) for the duration of the next price control period;
- an explicit adjustment to the level of reported losses may be made to reflect the impact of distributed generation with a loss adjustment factor (LAF) below 0.997. This adjustment will be the aggregate product of the difference between the site-specific LAF and 0.997, multiplied by the export volume of the generator; and
- expenditure on low-losses equipment will be treated as any other capex, i.e. it will be eligible for inclusion in the RAV and subject to the rolling capex incentive.

5. Distributed generation, innovation funding and registered power zones

Introduction

5.1. The government has put in place specific targets for the amount of energy to be supplied by renewable generation and the capacity of combined heat and power (CHP) to be installed by 2010. A significant amount of work has been undertaken over the past couple of years to develop the regulatory framework to accommodate the expected increase in the amount of generation connected directly to the distribution networks.

5.2. Previous consultation papers set out the proposed incentive mechanism for DNOs in respect of the connection of distributed generation to their networks. This included initial proposals for the level of pass-through and incentive rate for the costs associated with the connection of distributed generation (DG). This Chapter confirms Ofgem's proposals.

5.3. Ofgem has also previously published a report, produced by Mott-MacDonald & British Power International (MM-BPI), on the information submitted by DNOs on distributed generation.[18]

5.4. This Chapter also sets out Ofgem's proposals on the use of Registered Power Zones (RPZs) and the Innovation Funding Incentive (IFI), as developed through previous consultation documents.

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[18] "DG-BPQ Analysis: Summary of Findings", MM-BPI, March 2004

Incentive framework for distributed generation

5.5. Ofgem has proposed the introduction of a 'hybrid' incentive scheme for DNOs in relation to the connection of distributed generation, the broad characteristics of which are that:

- the costs incurred by the DNOs to provide network access to distributed generation are given a partial pass-through treatment; and
- the DNOs are be given a further supplementary £/kW revenue driver (or incentive rate) to incentivise the connection of distributed generation to the network.

5.6. The objectives of the incentive scheme are to:

- encourage DNOs to undertake the investment required to facilitate distributed generation connections (and generally be proactive and positive in responding to connection requests); and
- encourage DNOs to invest efficiently and economically.

5.7. This section confirms Ofgem's proposals on the detailed mechanics of the incentive scheme.

Level of pass-through

5.8. The most appropriate way of achieving a balance between the objectives outlined above is to use some form of hybrid incentive scheme that combines incentives for efficiency with protection against cost uncertainty.

5.9. Taking into account the views expressed by the respondents and the variability that is likely to be associated with distributed generation connections and to encourage DNOs to change behaviour and be proactive (rather than just focusing on cost minimisation), **Ofgem proposes to adopt an 80 per cent pass-through** rate for the incentive scheme.

Recovery of allowed revenue

5.10. DNOs have expressed concern about the predictability of actual revenue receipts. Ofgem has proposed that any over-recovery will be assessed against total revenue recoverable (i.e. revenue from all users of the network – not just demand consumers).

From whom should the DNOs recover the allowed DG revenue?

5.11. The total revenue that a DNO can recover under the DG incentive scheme (the pass-through and the incentive rate) should normally be recovered **from those generators connecting to the distribution system after 1 April 2005**.

5.12. The pass-through element, less any relevant connection charge associated with reinforcement, would be recoverable over the assumed asset life of 15 years on an annuity basis, starting in the year after the expenditure is incurred.

The value of the incentive rate

5.13. For most companies, Ofgem proposes an incentive rate of **£1.50/kW/yr** (based on an additional rate of return of 1 per cent above the current allowed cost of capital of 6.9 per cent – i.e. 7.9 per cent). Based on the views of its consultants, Ofgem's own work and the cost information reported by the DNOs, this figure appears appropriate for the majority of the DNOs. One DNO, Scottish Hydro-Electric, has been allowed a slightly higher incentive rate of £2.00/kW/year to reflect the higher than average costs identified by Ofgem's consultants for connecting distributed generation to its network.

5.14. Connection charges paid by the generator in respect of shared costs will be subtracted from the 80 per cent passed-through costs and the net amount will enter DNOs' allowed revenue under the hybrid mechanism.

O&M costs and the final incentive rate

5.15. The total capital expenditure costs of connecting distributed generation – including both sole-use and shared assets costs – were estimated by the DNOs to amount to around £82/kW. Ofgem has proposed an allowance of £1/kW/year to cover the on-going operation and maintenance (O&M) costs – equivalent to 1.22 per cent of the DNOs' own cost estimate of the capital expenditure.

5.16. The O&M figure will be reviewed at the time of the next price control review in 2010. If it appears that costs have fallen Ofgem would expect to pass the benefits of this on to generators in much the same way as the main price control works.

Recovery of the incentive rate

5.17. The incentive rate will be recoverable by DNOs once generating capacity connects to the distribution network and is only applicable whilst the generator remains connected to the network (i.e. continues to operate). DNOs will still be able to recover the incentive rate in instances where the generator decides to cease generating power temporarily (for example, due to weather and other conditions).

Locking-in the incentive rate

5.18. Ofgem has assumed that the asset life for capex associated with distributed generation will be 15 years. To ensure that DNOs have certainty about the amount of revenue that they will be able to recover over the life of the asset, then provided DNOs comply with the arrangements set out here it is intended that **the incentive (excluding the O&M charge)** applying at the time of connection will remain in place for the 15 year period, subject to the cap and floor on DNO returns set out below.

5.19. Ofgem will reconsider the level of the incentive rate at the time of the next price control review (or possibly sooner if the levels set cause problems) and a different incentive rate may be applied – but it is intended that this would only apply to new generating capacity connected after any decision to change the incentive rate is announced.

Floor and cap on DNO returns

5.20. To protect both the DNO and generators against cost uncertainty, Ofgem has proposed a cap and floor on DNO returns. This provides a floor to the rate of return on the overall portfolio of distributed generation connected in the next price control period, equal to the allowed cost of debt (4.1 per cent real, pre-tax).

5.21. To balance this, Ofgem also intends to cap the maximum rate of return on the overall portfolio of distributed generation connected in the next price control, to a level equal to two times the pre-tax equivalent of the allowed cost of capital (i.e. the cap is set at 13.8 per cent real pre-tax).

5.22. If, at the time of the next price control review, it appears that the expected pre-tax rate of return earned by a DNO on its overall portfolio of distributed generation connected is below (or above) the floor (cap) an adjustment will be made to the allowed incentive rate to bring the average rate of return for that DNO to the level of the floor (cap).

'High cost' projects

5.23. There may be certain projects which, because they are of such unusually high cost, or have requirements significantly in excess of the DNOs' design standards, are not adequately addressed within the parameters of the main DG incentive scheme. In such circumstances, Ofgem would expect the generator seeking connection (and giving rise to the costs) to fund the required additional investment through connection charges. Ofgem would expect that this would include any projects with direct reinforcement costs in excess of £200/kW – which is four times the average capital expenditure estimate.

5.24. Ofgem has considered whether a de minimis threshold should also apply in defining "high cost" projects to reduce the administrative burden but the DNOs have generally argued against this. On balance, Ofgem does not propose such a de minimis threshold.

Microgeneration

5.25. The DG incentive will apply to microgeneration in the same way as other distributed generation.

Incentives for ongoing network access

5.26. It is important that DNOs have incentives to provide ongoing network access (availability) to generators once they have been connected.

5.27. Ofgem initially proposed that an incentive of £0.002/kW/hour would be appropriate. The payment to generators would only be made in the instances where the DNO has failed to provide access to the network, not where the generator has chosen not to generate power (or is forced to cease generating due to weather or other circumstances).

5.28. In response to comments, Ofgem acknowledges that the administrative burden of this arrangement for very small generators may be disproportionate. Ofgem therefore proposes that the £0.002/kW/hour rebate only applies to generators connected at HV or above. Ofgem also proposes that generators connected at LV will have access to guaranteed standard payments in the same way as demand customers, which, in the case of the 18 hour standard, will provide broadly equivalent value for prolonged outages.

5.29. Ofgem notes that this incentive is intended to encourage the DNO to provide ongoing access to the network. It is not intended to provide compensation for economic loss. This incentive is expected to apply in circumstances where the generator has agreed on a standard connection. DNOs and generators would be free to agree variations in these terms as part of the bilateral connection agreement.

Definitions and reporting

5.30. It is important that clear definitions are provided to DNOs for the purpose of reporting performance under the incentive scheme to ensure that Ofgem can monitor and enforce compliance with the mechanics of the scheme. Ofgem has proposed a specific reporting framework, similar to that which has been used for quality of service, including providing reporting definitions and guidance notes.

Registered Power Zones

5.31. Ofgem recognises that for some new DG connection schemes, an innovative technical solution could offer material advantages to DG customers compared with a conventional solution. Where this is demonstrated to be the case, Ofgem proposes to provide an additional incentive of an extra £3/kW/year (over and above the main DG incentive) for a five year period commencing on the date of commissioning of the project.

5.32. Ofgem will register, though not approve, RPZ projects and, when appropriate, will seek advice from an independent panel, established by Ofgem, to confirm the innovation content and potential benefits of an RPZ proposal. The generator(s) directly involved in the innovation will have to be informed of the RPZ proposal and any technical and commercial impacts it might have compared with the extant connection option as part of the negotiation of a connection agreement.

5.33. The DNO would take full responsibility for the management of the risks of the scheme and would offer the connecting generator commercial terms reflecting these risks.

5.34. Open reporting of RPZ projects would be required annually; this is intended to stimulate good management and promote sharing of innovation good practice. A model form report will be established as part of the good practice guide. Technical performance monitoring information will be made available on request to bona fide parties and referenced in the annual report.

5.35. Where a DNO was successful in obtaining additional grant funding for an RPZ project, Ofgem would not withhold or modify the RPZ incentive.

5.36. DNOs will be allowed to seek registration for up to two RPZs per year for the first two years of the scheme. The RPZ incentive, including this registration limit, will be reviewed in 2007 together with the IFI.

5.37. The additional revenue (i.e. the revenue derived from the £3/kW uplift described above) that a DNO can claim for RPZ projects will be capped at £0.5 million per DNO per year. The cost of RPZ projects will be met by generators as a class within a DNO area in the same way as the DG incentive scheme.

5.38. Ofgem will be publishing further details of the RPZ scheme early in 2005.

Innovation Funding Incentive

5.39. Since privatisation, expenditure on research and development by DNOs has declined. In the current environment, where DNOs face a number of new challenges, it is questionable whether this is optimal. Ofgem has investigated the potential costs and benefits of additional development expenditure (rather than "pure" research) and found that the expected benefits seem likely to exceed the costs. Ofgem has also considered whether there is reason to suspect market failure in respect of R&D funding by DNOs. While this is not clear cut, it is possible that the regulatory system is perceived to be such that it undermines the commercial incentive to R&D that the patent system provides in other sectors (for example, because patents do not protect against the regulator transferring benefits to customers by reducing prices).

5.40. Ofgem has therefore proposed an Innovation Funding Incentive (IFI) to cover most of the cost of development projects focused on the technical development of distribution networks to deliver value (i.e. financial, supply quality, environmental, safety) to end consumers. IFI projects might be expected to embrace all aspects of distribution system asset management from design through to construction, commissioning, operation, maintenance and decommissioning.

5.41. Analysis of costs and benefits indicates that the funding resulting from this proposal is proportionate to the expected benefits. **Ofgem proposes a cap on costs eligible for IFI of 0.5 per cent of regulated revenue and that IFI funding will be on a use it or lose it basis.** A company will be allowed to carry forward from one year to the next year up to 50 per cent of the maximum allowable IFI funding for a given year. However, cumulative carry forward will not be allowable and the pass-through rate will be determined by the year in which the expenditure occurs.

5.42. It is important that DNOs should be exposed to some of the financial risk of R&D to encourage efficient expenditure. **Ofgem proposes to maintain the profile of pass-through set out in the table below.** The tapered pass-through has the further advantage of providing a greater incentive for first-movers.

Table 5.1 Pass-through of the IFI

Year	2005/6	2006/7	2007/8	2008/9	2009/10
Pass-through rate	90%	85%	80%	75%	70%

5.43. It is not the intention of the IFI to encourage DNOs to re-establish in-house R&D facilities. However, Ofgem recognises that to pursue IFI projects successfully the DNOs do need to invest a certain level of their own resources. Ofgem proposes that the IFI funding can be used to fund internal company expenditure but should be capped at 15 per cent of the total IFI funding in each year unless otherwise agreed with Ofgem.

5.44. Ofgem also proposes that any company that wishes to pursue IFI funded projects will have to produce and comply with a good practice guide for managing R&D projects. Ofgem proposes that there should be open reporting of IFI activities, including the potential benefit to consumers.

5.45. Ofgem has already proposed arrangements that allowed spending on IFI projects to commence in October 2004 and for qualifying costs to contribute to IFI revenue in 2005/06.

6. Metering

6.1. This Chapter sets out Ofgem's final proposals in relation to the metering price controls for DNOs in the transition to a competitive metering market. These price controls have been designed to protect customers in the transition to metering competition. The price controls cap the prices that former monopoly meter providers can charge suppliers for providing domestic credit and pre-payment meters and limit the revenue for Meter Operation, which is the installation and maintenance of meters, and establishes how the revenue control will adjust as the DNO's Meter Operation market share changes as competition develops. This Chapter also sets out the changes that Ofgem is proposing to Distribution Licence Standard Condition 36 – 36C to facilitate competitive electricity metering

Introduction

6.2. As noted in the Initial Proposals Document, Ofgem's objective in reviewing the price control treatment of metering services is to protect the interests of consumers through securing effective competition in those services.

6.3. In its Metering Price Control Consultation Document[19] Ofgem outlined the policy objectives in setting the metering price control. These objectives are:

- promoting competition in the provision of metering services
- allowing licence holders to finance their activities
- considering the interests of specified customer groups
- promoting efficiency and economy
- reducing the cost of metering to consumers, and
- facilitating the development of new technology.

6.4. Ofgem noted in the September Update Paper[20] that it has sought to balance the promotion of competition with providing a safeguard to consumers during the development of metering competition.

6.5. Ofgem considers that competition in metering will be the mechanism that best achieves its statutory duties over time.

6.6. The purpose of this section of the document is to outline Ofgem's final proposals in regard to the Metering Price Controls. It proposes metering price caps for a standard domestic credit meter and each of the prepayment meter (PPM) technologies currently provided by the Distribution Network Operators (DNOs). In relation to Meter Operation (MOp)[21], this chapter sets out the revenue cap and the driver which will adjust the revenue that the DNOs can earn.

6.7. The MOp revenue cap is based on the costs of providing these services with a 1.5 per cent mark up. This revenue cap will be adjusted for changes in chargeable activities.

Valuation of Assets

6.8. As outlined in the Metering Price Control Consultation Document, the value to be deducted from the distribution regulatory asset value (RAV) for metering is be based on the purchase price of a modern equivalent metering asset, depreciated in line with the DNO's depreciation policy to reflect the age of the asset.

6.9. The difference between the historic value and the depreciated replacement cost will remain in the distribution RAV. The benefit of this approach is that it will provide a more market orientated value to the metering asset thus facilitating competition and it will mean that the DNOs recover the difference between

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[19] Electricity Distribution Price Control Review – metering issues: Initial Consultation, July 2003
[20] Electricity Distribution Price Control Review: Update Paper, September 2004, 222/04
[21] MOp is the services currently performed by the DNO under Standard condition 36B of their licence. This includes the installation, commissioning, testing, repair, maintenance, removal and replacement of metering equipment.

what they were obliged to purchase as the result of licence obligations[22] and the market value of the asset.

6.10. The table below sets out the metering RAV for each of the DNOs.

Table 6.1 Metering RAV

DNO	**Metering Regulatory Asset Value £million**
CN – Midlands	16
CN – East Midlands	18
United Utilities	21
CE – NEDL	15
CE – YEDL	16
WPD – South West	15
WPD – South Wales	13
EDF – LPN	19
EDF – SPN	15
EDF – EPN	27
SP Distribution	22
SP Manweb	15
SSE – Hydro	9
SSE – Southern	14

Meter Asset Provision (MAP)

Price Caps

6.11. In the September Update Paper Ofgem set out price controls for domestic credit meters and for each of the PPM technologies provided by the DNOs. There has been a slight increase in the level of the allowed MAP charge. This reflects the increase in the pre-tax cost of capital used in these proposals from 6.6 per cent to 6.9 per cent. These new price caps are set out in Table 6.2 below. These prices will be indexed for inflation.

[22] The current Standard Condition 36B obliges DNOs to offer terms for the provision of a meter.

Table 6.2 Proposed MAP price caps

Meter Type	Price Cap £ per annum 2002/03 prices
Domestic Single Phase Single Rate	1.12
Prepayment – Token	8.56
Prepayment – Key	9.01
Prepayment - Smartcard	11.68

6.12. As noted in the September Update, the level of PPM MAP charges for some of the DNOs may rise in the short-term. In Scotland this is the result of the unwinding of the cross subsidy between domestic credit and prepayment meters for SSE Hydro Electric Power Distribution and SP Distribution.

6.13. It should be noted that whilst there may be rises in the PPM MAP cost for some DNOs, there is a reduction in the MAP charge for eight of the DNOs when compared to their current charges.

6.14. One concern raised in previous consultations has been that, by making PPM MAP more cost reflective, Ofgem is not considering the interests of consumers on low incomes. Ofgem notes that the MAP charge for a meter is only one aspect of the overall cost of servicing a PPM customer and a poor choice of meter can result in a rise in the overall cost of serving a PPM customer.

6.15. Ofgem considers that making the MAP charge for PPM cost reflective and establishing the MOp revenue control on a transactional basis then the true costs of those PPM technologies in use will become transparent to suppliers. This will act as an incentive for suppliers and DNOs to choose to install the technology that results in the lowest overall cost to serve the PPM customer. More efficient choices of meter type are very likely to result in a reduction in the cost of MOp and prepayment meter infrastructure provision. This reduction could mean an overall reduction in the cost of servicing a PPM customer. Ofgem is of this view because most of those regions that have MAP charges that may rise currently use Token PPM.

6.16. Token PPMs are of a very low functionality when compared to the two other technologies in use. For example, a Token PPM requires a site visit to re-programme for a tariff change or to make alterations to customer's debt. Neither the Key nor Smartcard PPM requires a visit for these purposes. Each additional visit has a cost associated with it. If the changes in tariff or to customer's debt require a visit from a DNOs meter engineer then the charge to the supplier is likely to be in the range of £20 per visit, twice the annual MAP charge. A move away from a Token PPM to a Key or Smartcard PPM should result in a reduction in the number of required visits to PPMs.

Adjustment mechanism for PPM

6.17. In the September Update, Ofgem proposed introducing an adjustment mechanism in the MAP price control for PPM. The reason for this was that the meters have been provided as a result of the regulatory obligation under standard condition 36B and previous price controls have not specifically addressed the issue of whether some types of PPM technology are less efficient than others. Given this it would be inappropriate for the entire cost of early replacement of these meters to fall on the DNO.

6.18. In their responses to the September Update Paper, a number of DNOs proposed termination charges as the fairest way to remunerate them for the early removal of their meter assets. Ofgem indicated in the September Update Paper that it did not support regulated termination charges.

6.19. Ofgem is establishing a price control because of its view that competition is not yet sufficiently developed to fully protect the interests of consumers. If Ofgem were to impose termination charges as part of the price controls then the current lack of competition would leave suppliers with little choice but to accept the regulated termination charges even if they were not in the suppliers' or consumers' best interests. The termination fees would effectively lock suppliers into contracts with DNOs until the meter was due for replacement. Therefore, Ofgem still considers that regulated termination charges in metering could stifle the development of metering competition.

6.20. It is Ofgem's view that the most appropriate mechanism to compensate DNOs for early retirement of metering assets is to adjust the PPM MAP price control. This will adjust the price cap for PPM assets in line with the reduction in the life of the meter asset as the result of supplier activity. The method that was used to calculate the price caps proposed in this document will be used to calculate any new price caps reflecting the shorter asset life. Ofgem does not consider that it's appropriate for customers to bear the full cost of premature removal of PPMs. Nevertheless, Ofgem recognises that DNOs had a licence obligation to provide PPMs and should not therefore be expected to bear the full cost of action taken by suppliers as a result of changes in the metering market. Ofgem considers that a maximum cap of 30 per cent on the reduction in asset life provides an appropriate balance between cost to the consumer and the DNOs.

6.21. Ofgem will decide on a case by case basis the appropriate reduction in the PPM asset life, based on information supplied by the DNOs that meters are being removed early by suppliers or their agents and that the early removal is having a material affect on their ability to recover the outstanding value of the assets.

6.22. An example of the price cap for the DNO's remaining PPM for every year's reduction in the asset life is set out in the table 6.3 below.[23]

Table 6.3 Adjustments to price caps following reductions in asset lives

Years reduction	Token PPM (£ per year)	Key PPM (£ per year)	Smartcard PPM (£ per year)
1	9.28	9.81	13.23
2	10.19	10.83	15.40
Maximum	11.26	11.88	15.67

Non-Discrimination Provision for other Non Half Hourly Meters

6.23. Ofgem proposes to introduce a special licence condition provision that prevents the DNOs from discriminating in the provision of meters. This will require the DNOs to adopt a similar basis for calculating the charge for other non half-hourly meter types as Ofgem used in calculating the price caps. That is, the DNO will be limited to charging a price that reflects the modern equivalent asset

[23] These numbers are provided for indicative purposes and are in no way fettering Ofgem's discretion in regard to reductions to asset lives of PPM.

value spread over the expected life of the meter plus a 6.9 per cent pre tax cost of capital and operating costs allocated on a per meter basis.

Meter Operation (MOp)

6.24. Ofgem is proposing a revenue cap for MOp. The level of this revenue cap will adjust in line with a revenue driver based on the volume of work the DNOs are undertaking in relation to metering.

6.25. The DNO must make take all appropriate steps within its power to ensure that its revenue does not exceed the total revenue calculated under the revenue control[24]. It is Ofgem's view that after 1 April 2005 where a DNO does not charge on a transactional basis it is unlikely they would be able to satisfy the requirement to take all appropriate steps. Therefore, should a DNO not charge on a transactional basis and breach its price control that DNO may be subject to enforcement action under its licence.

Starting Revenue

6.26. In the September Update Paper Ofgem published its initial proposals for the MOp revenue control.

6.27. In their responses to the September Update Paper a number of DNOs suggested that Ofgem should set price caps on a few basic activities with a non-discrimination clause to cover other activities. Ofgem is proposing a revenue control rather than a price cap as it allows the DNOs more freedom when setting their charges to reflect their business strategy and it allows recovery of fixed costs as the DNOs market share diminishes as competition develops.

6.28. Some minor amendments have been made to the model for the MOp revenue control which has resulted in a slight increase in the overall allowed MOp revenue. The first was to correct a minor error that meant the cost per activity was not being calculated on the 60th percentile as Ofgem had indicated it was in

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[24] Wording from the proposed licence condition for the distribution price control.

the September Update Paper. This led to a small increase in the calculated costs. The second was an amendment to how overheads were allocated for one of the DNOs used to establish the costs of the DNOs' metering businesses. The change allocated indirect costs across all metering activities, not just those subject to the revenue control, this resulted in a very minor downwards change to the revenue control.

6.29. The September Update Paper highlighted a concern in relation to the definition of basic metering services in MOp. In that paper Ofgem was proposing to define basic MOp by referring to the type of service in the industry contracts as at 1 June 2003. Ofgem was concerned that these contracts may be open to manipulation through changing the mix of appointment times. Ofgem therefore proposed in the event that the contracts were open to manipulation that Ofgem would issue a determination as to what amounted to a basic service. This determination would exclude appointments other than the standard industry appointment.

6.30. Following consultation with the DNOs, Ofgem has concluded that the industry contracts referred to in the proposed definition are not sufficiently robust to maintain the mix of appointments. However, Ofgem's approach discussed below means that a determination will be unnecessary.

6.31. Ofgem is proposing an amendment to the standard licence conditions that will oblige the DNOs to provide all the types of appointments that they were offering as of 1 June 2003. However, the revenue control will be restricted to standard appointments only[25]. Revenue associated with appointments other than the standard appointment will be covered by the condition to set metering excluded service charges in a cost reflective manner. However, Ofgem proposes to lift in April 2007 the obligation to provide any type of metering appointment.

6.32. In the September Update Paper Ofgem proposed a mark up on MOp cost of 1.5 per cent to create an appropriate rate of return for DNOs in relation to MOp. In

[25] A definition of standard appointment based on current industry practices will be used in the special licence conditions.

their responses to that document DNOs indicated that they felt that a 1.5 per cent mark up was insufficient and some DNOs indicated that the mark up should be in the range of 10 per cent to 20 per cent. Some suggested that an electricity contractor was a comparable business. Ofgem is not convinced of the similarity between the two businesses. The electricity contractor does not have the capacity to recover stranded costs in the same way as the DNO metering business does. The electricity contractor is not a regulated business which has inherited substantial market share. An electricity contractor justifies their return by reducing their costs in a competitive exercise.

6.33. In developing a cost mark up Ofgem is of the view that it should be set at the level that provides a sufficient return on the capital investment in the business. Ofgem remains of the view that a 1.5 per cent mark up on cost provides an appropriate return in relation to the capital required to establish a metering business.

6.34. In the September Update Paper Ofgem indicated that the proposed revenue control could change where DNOs could demonstrate to Ofgem that their costs and activities are different to those that were proposed by Ofgem. A number of DNOs were able to do so.

6.35. There are several notable changes from the September Update Paper. Central Networks – Midlands were able to prove to Ofgem that their costs and activity mix were different to those suggested by Ofgem's calculations. United Utilities satisfied Ofgem that 2002/03 was not a representative year in terms of activities and would result in an outcome that distorted their revenue control for future years. Ofgem has adjusted this to make the revenue control more representative of United Utilities' normal level of activity. Ofgem has also provided a regional weighting for the MOp costs of SSE Hydro Electric Power Distribution and EDF LPN in line with the regional weightings set in the main distribution price control.

6.36. Table 6.4 below sets out the revenue cap as proposed by Ofgem in the September Update Paper and that which Ofgem is proposing now.

Table 6.4 Meter Operation starting revenue

DNO	September Update Paper (£m per annum)	September Update Paper – Excluding Appointment Revenue (£m per annum)	Final Proposal[26] (£m per annum)
CN – Midlands	8.3	7.65	8.39
CN – East Midlands	9.4	8.74	8.74
United Utilities	4.9	4.51	6.20
CE – NEDL	8.1	7.40	7.52
CE – YEDL	7.9	7.30	7.42
WPD – South West	6.5	5.96	6.06
WPD – South Wales	4.5	4.12	4.19
EDF – LPN	7.1	6.49	7.95
EDF – SPN	8.6	7.93	8.73
EDF – EPN	11.7	10.64	10.78
SP Distribution	4.5	4.15	4.66
SP Manweb	3.4	3.14	3.66
SSE – Hydro	2.8	2.54	2.69
SSE – Southern	9.7	8.95	9.09

Drivers

6.37. In its Initial Proposals Document Ofgem proposed a revenue control for MOp where the revenues derived are adjusted by changes to the number of meters. In the September Update Paper Ofgem indicated concern about how representative the numbers of meters are as a driver for MOp revenue.

6.38. Therefore, Ofgem is proposing to use chargeable activities as the revenue driver. A chargeable activity is a visit by a DNO to a meter point that involves a transaction that the DNO can charge for under current industry agreements. Three revenue drivers will be used to adjust the MOp revenue control. These are poly phase meter chargeable activities, CT meter chargeable activities and single phase chargeable activities. Single phase, poly phase and CT meters differ in the way in which they are connected to the distribution system. A rough guide for those not familiar with the distinction between these categories is that single phase meters tend to be of the type found in the average domestic premises (both standard credit and PPM). Poly phase meters may be installed in larger domestic premises and many non-domestic premises. CT meters tend to be restricted to the larger industrial and commercial premises.

6.39. Chargeable activities are largely categorised by the nature of the meter upon which the work is performed. A guidance list of chargeable activities and whether they are single phase, poly phase or CT metering can be found in the appendix to this document. The question of whether something is a chargeable activity and which category it falls into is a question of fact. In areas where there is uncertainty then DNOs can approach Ofgem for clarification.

6.40. The amount that DNOs' MOp revenue will change by as the result of a change in activities is set out in the Table 6.5 below.

Table 6.5 Chargeable activity drivers

Chargeable Activity	Driver (£ per activity)
Single Phase (S)	21.37
Poly Phase (P)	34.91
CT Metering (C)	106.67

6.41. The calculation of the drivers assumes that 22 per cent of the costs of the DNOs are fixed. This proportion is derived from Ofgem's analysis of the DNOs' historic costs.

6.42. The following formula sets out the operation of the revenue driver. Where t designates the relevant year for the calculation and the value in the table above is indexed by inflation.

$$\text{Total Revenue MOp}_t = \text{Total MOp}_{2002/03} - ((\text{Poly phase Activity}_{2002/03} - \text{Poly phase Activity}_{t}) \times P) - ((\text{CT Metering Activity}_{2002/03} - \text{CT Metering Activity}_{t}) \times C) - ((\text{Single Phase Activity}_{2002/03} - \text{Single Phase Activity}_{t}) \times S)$$

[26] As noted in paragraph 6.31 this also excludes revenue from non standard appointments.

6.43. This formula shows that the DNO's revenue will move up and down with changes in activity when compared to 2002/03. The only exception to the 2002/03 base year is United Utilities, whose revenue control is based on more representative activity level.

Excluded Metering Service Revenue

6.44. All activities performed by the DNO's metering business but which do not form part of the modified standard condition 36 obligations will be treated as Excluded Metering Service revenue. Ofgem will be including a specific clause in the special licence conditions that will require the DNOs to set their charges for Excluded Metering Services on a basis that reflects the costs incurred in performing those services.

Amended Standard Licence Condition 36

Basic Metering Services

6.45. The definition of basic MAP service remains the same as proposed in the September Update Paper. A basic meter is a meter of the same functionality as provided by the DNO as at 1 June 2003.

6.46. As noted in paragraphs 6.29 to 6.31, the September Update Paper highlighted concerns that Ofgem had with the mix of appointments and the contracts in place as of 1 June 2003 in regards to MOp. As noted in paragraph 6.31, the solution arrived at is to require the DNOs to provide the same types of appointments as they did at 1 June 2003 but to have appointments other than the standard appointment covered by the requirement that charges be set on a cost reflective basis.

One Way Door

6.47. In the Initial Proposals Document Ofgem indicated that it would be proposing to modify the DNOs' licence obligation to provide MAP or MOp. The modification lifts the obligation to provide MAP or MOp so that it does not apply to a given supplier in relation to meter points at which that supplier has de-appointed the DNO as MAP or MOp.

6.48. Table 6.6 below outlines this concept.

Table 6.6 De-appointment of DNO as a meter service provider

Activity	Is the DNO required to provide MAP	Is the DNO required to provide MOp
Supplier de-appoints DNO as provider of MAP and MOp	No	No
Supplier de-appoints the DNO as provider of MAP	No	Yes
Supplier de-appoints the DNO as provider of MOp	Yes	No
Change of Supplier: New supplier who has never de-appointed the DNO for that meter point takes over a meter point where Old Supplier de-appointed the DNO as MAP and/or MOp	Yes	Yes
Change of Supplier: New supplier who had previously de-appointed the DNO for MAP and MOp at that meter point takes over the meter point of a supplier who had not de-appointed the DNO for either MAP or MOp	No	No
New Supply Point	Yes	Yes

6.49. One respondent to the September Update Paper felt that this approach could affect the decision by the supplier as to whether to contract out their meter services. However, it is Ofgem's view this is unlikely to pose a significant impediment considering the obligation on DNOs to provide MOp and future MAP is proposed to end from 1 April 2007 when metering competition should be more developed.

6.50. Those meter points at which the supplier de-appointed the DNO after 28 June 2004 will be included in the one way door. Those de-appointments that took place on or before 28 June 2004 will not be included. The reason for this is 28 June 2004 is the date of the publication of the Initial Proposals Document outlining the operation of the One Way Door. It is Ofgem's view that it is unfair on suppliers to backdate the operation of the one way door prior to this date.

6.51. The DNO will still be under an obligation to provide MAP and/or MOp where a supplier takes over a meter point at which the outgoing supplier has de-appointed the DNO, or at new meter points. Furthermore, if the DNO is de-appointed as MAP or MOp they are still under an obligation to provide the other service until de-appointed or the licence obligation is lifted.

Switch Off

6.52. The obligation to provide new meters and MOp will end on 1 April 2007 unless the Authority directs that they should continue.

6.53. Ofgem anticipates that it will conduct a competitive market review prior to the switch off to determine the state of competition in electricity metering. The outcome of this will then be used as part of the decision on whether to lift the obligations under condition 36 – 36D and the price controls for MOp and future MAP.

7. Assessing costs

Introduction

7.1. A key part of the price control review is the assessment of companies' future costs. Ofgem's assessment has considered each company's actual costs and projections but has also made substantial use of comparative analysis across companies.

7.2. Over the past year, Ofgem has devoted substantial resources to assessing the companies' historical and forecast costs. The cost assessment work began with the specification of detailed information requests, in consultation with the companies. The completed business plans were initially submitted in stages – historical information in September 2003 and forecasts in December 2003 and January 2004, but a number of resubmissions were necessary. Ofgem and its consultants have visited each group on a number of occasions, including 2-3 day visits in October/November 2003 and February 2004, and one day visits in March (Ernst & Young) and in April/May. Subsequent to initial proposals, Ofgem met with each DNO management team on a number of occasions to discuss aspects of the cost assessment.

Operating costs

7.3. Ofgem has used a five stage approach to operating cost assessment:

- ♦ reviewing the cost and efficiencies achieved by DNOs during the existing price control period, their projected efficiencies for the rest of this price control period and the next;
- ♦ developing "normalised" and comparable cost information using actual costs from 2002/03;
- ♦ comparing actual normalised costs, using top-down benchmarking, to help estimate efficient cost levels;
- ♦ considering other information on efficiency e.g. Ernst & Young's operational efficiency work, the views of Duncan Whyte (former COO

and FD of Scottish Power), including DNOs' forecasts of changes in activity levels and new future costs, adjusting results where necessary, and rolling forward to 2010; and

- adding back other cost items estimated separately (e.g. business rates, pension costs, etc) to give the final opex allowance.

7.4. Cost savings achieved in the first three years of the existing price control period were summarised in the December 2003 consultation document. DNOs' forecasts were summarised in the March 2004 document.

7.5. The main issues arising in establishing the operating cost allowances were:

- normalisation;
- regional factors;
- establishing a benchmark;
- treatment of mergers;
- additional allowances for vegetation, exceptional events and quality improvements;
- comparison with 2003/04 analysis;
- comparison with forecasts; and
- business rates.

7.6. These are addressed in turn below.

Normalisation

7.7. Ofgem has undertaken substantial work to bring company data onto a more comparable, or "normalised" basis. One of the significant differences between companies was in the allocation of costs relating to faults occurring on the network. To minimise the impact of differing treatments, the normalisation process has considered operating costs plus total fault costs.

7.8. Apart from a minor change to use updated pension information the normalisation adjustments are the same as set out in the September Update document and are summarised in Table 7.1. The right-hand column of this table (totalling £821m) shows the cost values used in the comparative analyses.

7.9. In this review, the normalisation process has revealed significant divergences of accounting policies and practices which have required extensive adjustment, not just to the 2002/03 base year data but also to other years in order to allow the roll-forward of the Regulatory Asset Values on a basis consistent with the last price control review. Ofgem considers that, in future, it will be important to collect cost data on a more comparable basis from DNOs each year. The proposed timetable for this work is set out in Chapter 2. Each of the DNOs has committed to support and contribute to this project.

7.10. Due partly to data issues, the normalisation work at this review has not explicitly excluded all non-operational property rental and lease costs, even where these costs have only arisen as a result of disposals by the DNOs of assets they inherited at privatisation. This issue would merit consideration at future reviews.

Table 7.1 Normalisation of DNOs 2002/03 Opex + Total Fault Costs (£m, 2002/03 prices

	DNO	HBPQ Opex + Total Faults	Normalisation Adjustments						Normalised Opex + Total Faults
			Atypicals & one offs	Intra co margins	Average f'cast non op capex	Overheads	Other	Reg Adj & 132 Kv	
		£m	£m	£m	£m	£m	£m	£m	£m
1	CN - Midlands	66	1	(1)	-	4	(2)	-	67
2	CN - East Midlands	71	(11)	-	2	-	2	-	63
3	United Utilities	43	20	-	7	(4)	4	-	70
4	CE - NEDL	43	(1)	(1)	3	(8)	4	-	41
5	CE - YEDL	57	(1)	(0)	4	(9)	4	-	55
6	WPD - South West	40	8	(1)	7	(0)	1	-	54
7	WPD - South Wales	37	(4)	(0)	6	(0)	0	-	38
8	EDF - LPN	62	(4)	(2)	7	6	(1)	(6)	62
9	EDF - SPN	66	1	-	7	-	(4)	-	69
10	EDF - EPN	88	(8)	(6)	10	6	(3)	-	88
11	SP Distribution	61	(4)	(5)	-	8	(0)	4	63
12	SP Manweb	61	(4)	(5)	-	1	(0)	-	53
13	SSE - Hydro	36	(0)	(1)	0	-	1	0	36
14	SSE - Southern	63	(3)	(2)	1	3	(0)	-	62
	Total	**793**	**(12)**	**(23)**	**53**	**7**	**6**	**(2)**	**821**

Notes

1) HBPQ Opex + Faults shown here already excludes metering costs, network rates, Ofgem licence fee, depreciation and exit charges.
2) Figures have been rounded to the nearest £million, 0 indicates a figure below £0.5m, - indicates a zero balance.

Regional factors

7.11. Ofgem acknowledges that all the companies could claim certain costs that are unique or different due to their network or geography. At the last price review, Ofgem considered that operating cost conditions were broadly similar for all companies with the exception of EDF-LPN and SSE-Hydro. It is commonly recognised that employment costs are higher in London. SHEPD has a very large sparsely populated territory and as a result, incurs additional operating costs. This approach has been continued here, with regional factors included in the analysis for EDF-LPN and SSE-Hydro.

7.12. As explained in the September Update, Ofgem has given further consideration to this issue, including the potential impact of regional variations in employment costs, particularly in relation to EDF-SPN. A significant difficulty is that some regional factors can be quantified more readily than others. However, even for wage costs, conflicting views have been presented. Several DNOs accept that the various impacts approximately offset each other and there would appear to be some validity to this argument. Ofgem therefore proposes to continue with its approach in previous reviews and not make adjustments for other companies.

7.13. For EDF-LPN, it is arguable that the choice of weightings on the composite scale variable and the use of weather-related analysis to determine exceptional event allowances also risk disadvantaging the company. These proposals therefore include an additional adjustment to EDF-LPN's costs of £1.7m per annum, taking the total regional allowance for EDF-LPN to £7.8m per annum.

7.14. The regional allowance for SSE-Hydro is £1.6m per annum. This is unchanged from the proposal in Initial Proposals and the September Update.

Establishing a benchmark

7.15. The normalised costs discussed above have been compared to determine relative efficiency and to establish a benchmark efficient cost level using a statistical regression technique called corrected ordinary least squares (COLS). However this is not a purely mechanistic process and there are a number of issues Ofgem must consider to ensure the resultant cost allowances are sustainable and robust.

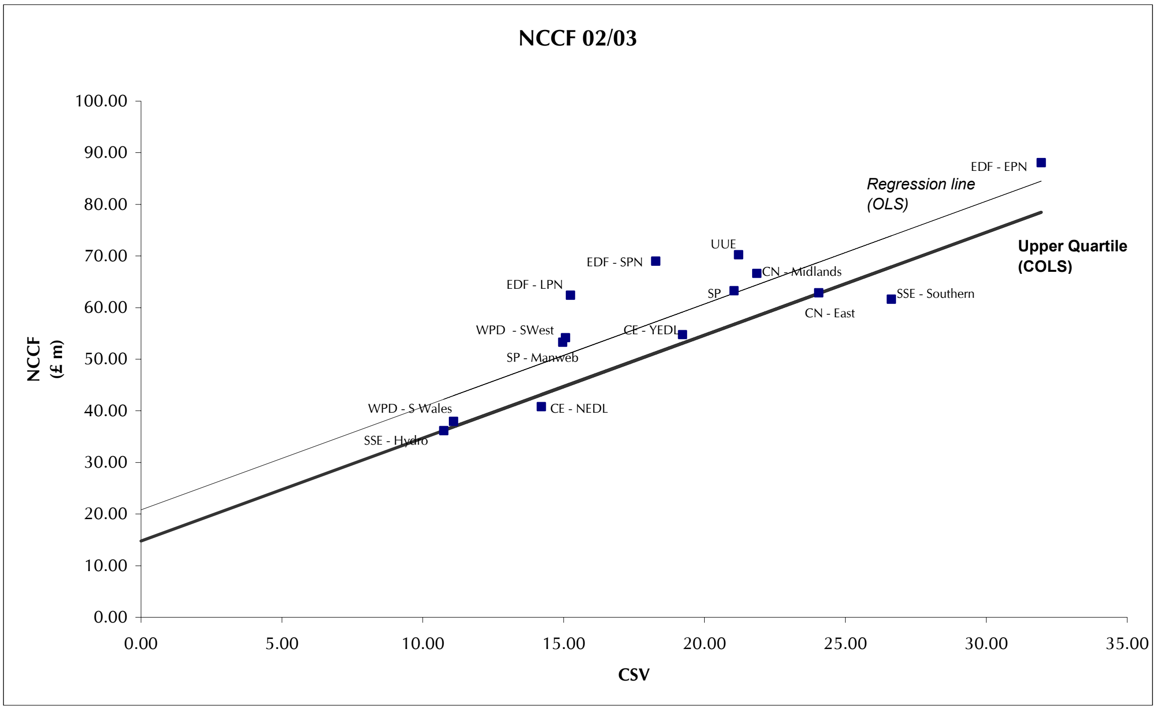
7.16. The first step in regression analysis is to determine the explanatory variables. As at previous reviews, Ofgem considers that the primary driver of DNOs' operating (and fault) costs is the size of the network. In the regression analysis, network size is measured by network length, customer numbers and units distributed. These are combined into the composite scale variable (CSV). Network length has been weighted at 50 per cent and customer numbers and units distributed at 25 per cent each.

7.17. The DNOs have expressed different views on this matter, particularly regarding the weighting of network length. Having considered the available evidence, Ofgem's view is that the weighting described above represents an appropriate balance of cost drivers. As mentioned above, one exception is EDF-LPN which given its small highly dense network may be relatively less affected by network length than other DNOs. As set out in paragraph 7.13, an extra allowance has been given to EDF-LPN to reflect this. The figures for the CSV are set out in Appendix 3. They are unchanged from those set out in the Initial Proposals document in June.

7.18. The base regression uses the 14 DNOs as separate data points and regresses normalised controllable costs and faults (NCCF) on the CSV as defined above. Given the issues that arose in normalising the data, Ofgem considers that use of a single outlier to determine the frontier would not be prudent in this case. It is a characteristic of this particular data set that a corrected ordinary least squares (COLS) analysis set to pass through the upper quartile efficiency level runs close to the cost levels of several companies, which provides a measure of confidence in its robustness.

Figure 7.1 shows the results of this base regression.

Figure 7.1 Base regression using 2002/03 data for 14 companies



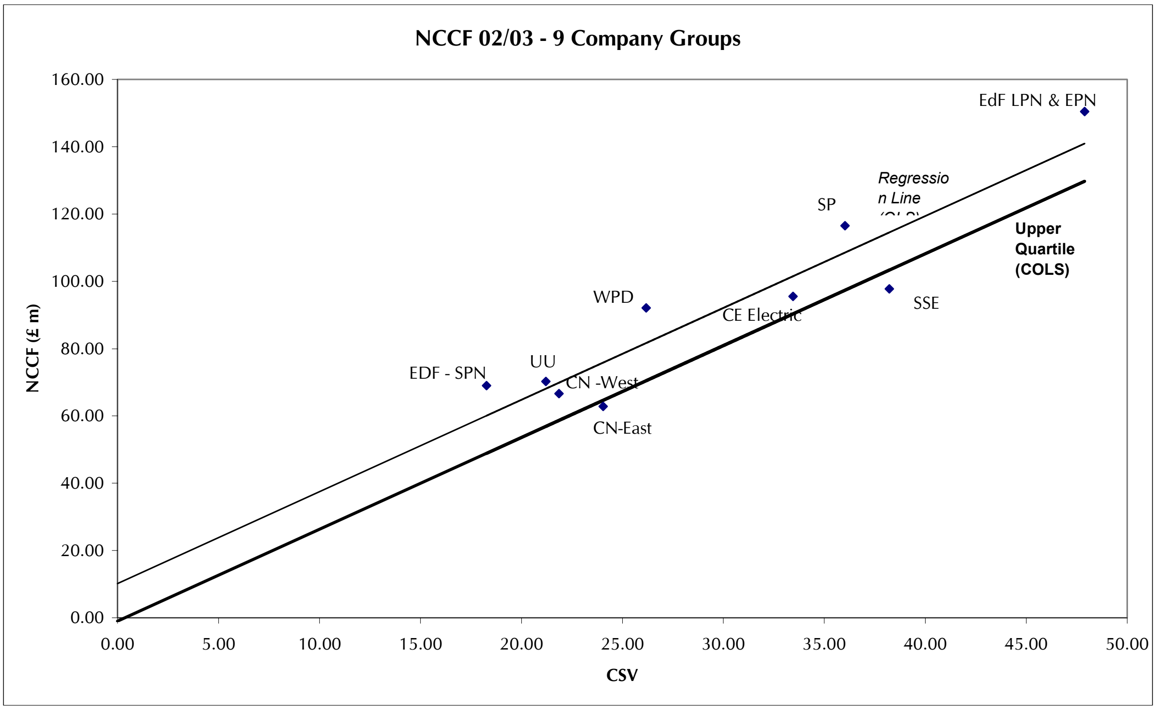
7.19. DNOs have argued that there are other factors that affect efficiency that are not captured in the base regression. In particular they have suggested that the effect of mergers between DNOs, the interaction between opex and capex and the effect of quality of service should be included in our analysis and that data envelopment analysis should be used.

7.20. As discussed in the June and September papers Ofgem has considered these arguments and has produced alternative analyses. The effects of mergers and the interaction between operating costs and capex are discussed below. On quality of service, alternative regressions have not demonstrated a statistically significant link to quality, perhaps because a relatively small proportion of operating costs affect the quality measures, so the opex analysis has not been adjusted for quality of service. Data envelopment analysis has been used as a cross check, but as discussed in the September Update paper, aspects of the results are not plausible so it has not been incorporated directly.

7.21. The simplest approach to assess the impact of mergers on economies of scale is to aggregate the data for the 14 licensees into data for the 9 company groups in existence on 1 April 2002, the base year for the analysis.

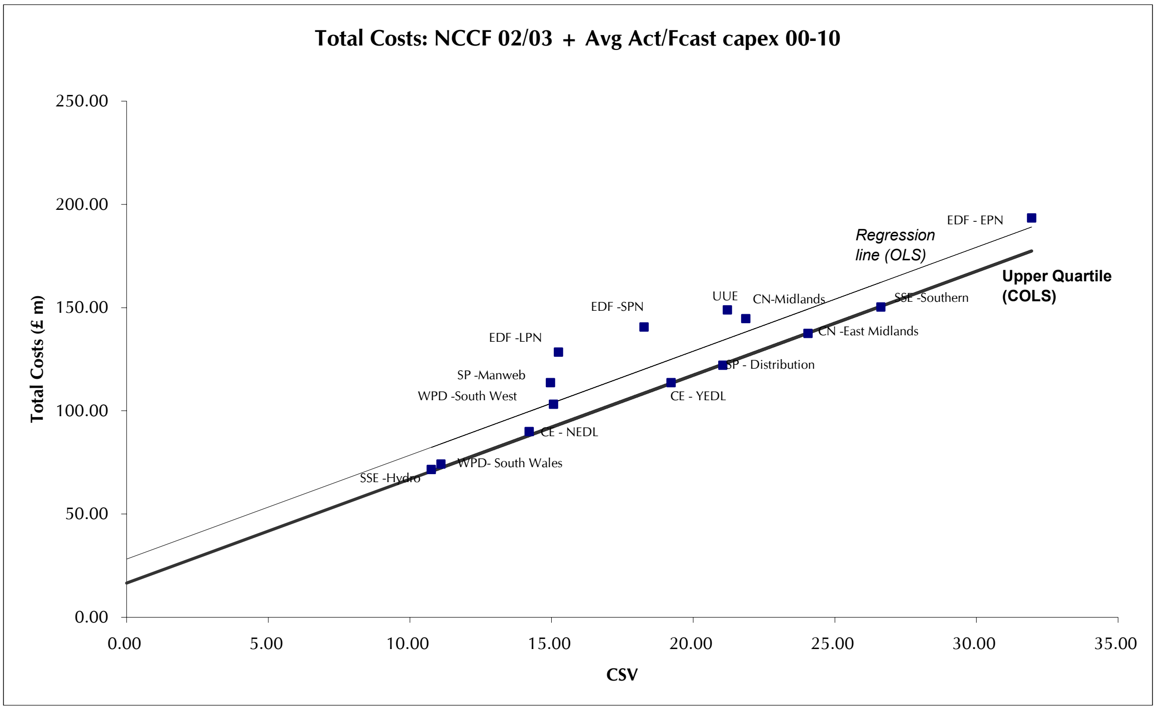
7.22. Figure 7.2 shows this analysis. (The two Central Networks DNOs and EDF-SPN are therefore still shown as being in separate ownership).

Figure 7.2 Regression using 2002/03 data for 9 ownership groups



7.23. Ofgem has considered several versions of total cost analysis. These differ mainly in how they take account of capital expenditure. In particular, various different versions of capital consumption could be used, none of which are necessarily appropriate and which would not generally capture short-term substitution (or differences in classification) between opex and capex. To capture some of the classification issues, Ofgem has considered a simple form of the analysis which adds projected average capital expenditure over the period 2000-2010 to NCCF. Figure 7.3 shows an updated version of this analysis.

Figure 7.3 Total cost analysis using average capex 2000-2010



7.24. As can be seen from each of figures 7.1 to 7.3, a number of DNOs are ahead of or close to the upper quartile benchmarks in each case - therefore using this benchmark ensures that the overall view of efficiency is not reliant on a single DNO. Ofgem has therefore used the upper quartile to set benchmark costs for this price control as it is more robust than using a frontier that relies on a single company.

7.25. Having considered these various approaches, Ofgem's view is that none of them is necessarily superior to the base regression shown in Figure 7.1. However, some of the alternatives do provide additional evidence and where these in aggregate (for example, taking the average efficiency scores implied by Figures 7.1, 7.2 and 7.3) suggest that the cost allowances implied by Figure 7.1 would be too low, Ofgem considers that this should be taken into account. The starting point for the opex allowances has therefore been derived from the efficiency scores using the higher of the base regression and the average of the three regressions (see table A5 in Appendix 3).

7.26. In order to maximise the impact on incentives, Ofgem proposes that, in general, all companies will be given allowances based on achievement of this upper quartile by 2004/05; i.e. no extra time or "glidepath" is given to DNOs with higher costs to achieve benchmark cost levels.

7.27. Further, both a total factor productivity study commissioned by Ofgem (Cambridge Economic Policy Associates, Productivity Improvements in Distribution Network Operators, November 2003) and the business plans of several DNOs suggest that ongoing efficiency savings will be achievable in the next price control period. Considering the available evidence, Ofgem has set operating cost allowances for the period 2005/06 to 2009/10 based on a 1.5 per cent per annum reduction in underlying efficient costs over this period, before additional costs are considered.

Treatment of mergers

7.28. In the September Update Ofgem discussed the validity of making comparisons between merged DNOs and those DNOs not merged in 2002/03[39] ("singletons"). Ofgem considers that comparisons on a "per ownership group" basis are a valid approach to comparing companies with different ownership structures. Further, one of the companies setting the upper quartile benchmark in the baseline regression is CN-East, which indicates that the benchmark can be achieved by a single DNO.

7.29. Nevertheless Ofgem acknowledges that the basis for setting allowances described above does not rely solely on the 9 group analysis. It is also arguable that mergers could enable companies to achieve cost reductions more quickly and that non-merged DNOs could therefore take longer to achieve upper quartile cost levels. To reflect this, Ofgem now proposes to provide additional allowances for singletons to provide a longer period of time to achieve the upper quartile.

7.30. For these final proposals, allowances have been set on the assumption that those DNOs that were single at the start of 2002/03 will move only half way to the upper quartile by 2004/05, starting from their actual costs in 2002/03 or from the upper quartile level of those singletons, whichever is higher. The allowances then assume that the remaining half of the gap to the upper quartile is closed by the fifth year after any merger or after the start of the price control, whichever is sooner. (For example, EDF-SPN is assumed to reach the upper quartile in 2007/08, the fifth year after its merger with EDF.)

7.31. For those companies that were already merged at the start of 2002/03, the merger policy that was in place at the time of their merger has been applied as far as reasonably practical. Ofgem has checked that the cost allowances being set deliver at least a £12.5m (in 1997/98 prices) reduction against previous allowances and has assumed that those companies achieve the benchmark cost level by 2004/05. The main difference to the published policy is that the benchmark has been set at the upper quartile rather than the frontier, which Ofgem considers is appropriate for the reasons set out above relating to the robustness of reliance on a single frontier company. Unlike at the last review, no further reduction in costs has been assumed to occur five years after each merger.

Vegetation, exceptional events and quality improvement

7.32. In addition to the potential for future efficiency there are also upward cost pressures which must be recognised such as, for example, changes to activity levels which may not be reflected in the base year (2002/03) that Ofgem has considered in setting the operating cost allowances. One example is tree-cutting, where most companies are forecasting an increase in activity above 2002/03 levels.

7.33. Ofgem accepts that an increase in tree-cutting activity is appropriate in the light of public concern over the level of disruption and, in some cases, the slow pace of supply restoration following major storms. Ofgem has reviewed DNO forecasts and modelled the direct costs of tree cutting. Based on this analysis, operating cost allowances have been increased to take future higher activity levels into account where appropriate. The additional allowances are intended to allow for the direct cost of the increased activity as Ofgem does not consider additional indirect cost allowances are warranted. No increase in allowance has been given for catch up of any backlog in tree cutting since Ofgem considers that this expense should be borne by shareholders rather than customers.

7.34. Ofgem has modelled tree-cutting costs in two ways - one based on the direct costs of performing this work in-house and the other on the average of existing third party contractor rates. The average of the results of these two approaches has been compared to the implied allowance for tree cutting in efficient regressed costs (assuming average cost per CSV of the upper quartile companies). Where the average cost from the tree cutting model is greater than that implied from the regression, the allowance has been increased accordingly. Increases to the allowances are set out in Appendix 3.

7.35. In total, these Final Proposals include specific allowances worth a total of £70m per year for vegetation management (tree-cutting), exceptional events and quality improvements (increased allowance for fault costs). The approach to exceptional events and quality improvements has been discussed in Chapter 4 above.

Comparison with 2003/04

7.36. Since Initial Proposals were published DNOs have provided actual cost data for 2003/04. Although this data has been subject to a limited normalisation exercise, it has not been possible to subject it to the same degree of assessment and normalisation as the 2002/03 data so this data has not been used directly to set allowances.

7.37. The comparison of 2003/04 costs with 2002/03 is shown in the September Update Paper (Table 4.2). In total, costs rose by 2.4%, to £799m. However, this increase is more than fully explained by special factors, such as increased tree cutting costs (for which there is a separate allowance in these proposals), higher corporate recharges and lower identified atypicals. Excluding these factors Ofgem estimates that underlying costs in 2003/04 were at least 1 per cent and potentially of the order of 3-4 per cent lower than in 2002/03. This is consistent with Ofgem's view that there is scope for further efficiency improvements from the 2002/03 baseline.

7.38. As part of the project on reviewing network monopoly price controls in early 2003, Ofgem committed to ensuring that incremental cost savings made after 1 April 2003 would be retained for 5 years. In March 2004, Ofgem described in more detail how this mechanism was intended to work, including an explanation of why it was not appropriate to make any adjustments in respect of cost savings in 2004/05.

7.39. It is arguable that the cost assessment methodology used at this review automatically meets the commitment to allow incremental savings made in 2003/04 to be retained for at least five years. However, some DNOs have argued that they relied on the detailed mechanics of the mechanism published by Ofgem. Recognising the benefits of reliance on incentives, Ofgem therefore proposes to apply the rolling retention mechanism as set out in March. This requires assessment of operating costs on a comparable basis to the allowances set at the last review, which involves reversing any adjustments made in the RAV roll-forward. Where costs in 2003/04 on this basis show a greater out-performance against the allowance than previous years in the current price control period, additional revenues are allowed. This gives rise to increased allowances for CE - YEDL of £6.4m, United Utilities £1.5m and WPD - South Wales £0.3m for each of the years 2005/06-2007/08 so that the benefit of incremental efficiencies achieved in 2003/04 is retained for 5 years.

7.40. Ofgem considers that, in principle, rolling incentive arrangements, including for operating costs, provide a useful way to maintain the strength of incentives throughout a review period. However, due to problems over data comparability Ofgem does not intend to apply a rolling incentive mechanism to opex in the future (i.e. from 2005/06 onwards), at least until it is satisfied that the cost reporting exercise has been successful. Once this exercise is complete, Ofgem will review its approach to rolling opex incentives in the future.

Comparison with forecasts

7.41. The comparison of the proposed allowances against the companies' own forecasts is shown in Table 7.2 below. This analysis has been updated from that shown in the September Update.

Table 7.2 Comparison of average annual opex allowance to company opex forecast (2005-10)

DNO	Company Forecast	Final Proposals	Difference
	£m	£m	£m
CN - Midlands	66	61	(5)
CN - East Midlands	64	65	1
United Utilities	73	58	(14)
CE - NEDL	42	43	0
CE - YEDL	53	52	(1)
WPD - South West	55	47	(9)
WPD - South Wales	36	40	4
EDF - LPN	71	52	(19)
EDF - SPN	68	52	(16)
EDF - EPN	100	82	(18)
SP Distribution	55	56	0
SP Manweb	42	46	4
SSE - Hydro	38	38	(1)
SSE - Southern	66	69	3
Total	**830**	**759**	**(71)**

7.42. Some care is required in interpreting the information shown in Table 7.2 since the comparisons may not be on a fully like-for-like basis. For instance, the proposed allowances include allowances for additional tree-cutting expenditures, fault restoration costs and atypical event costs. Expenditure on these items was included to varying degrees in the companies' forecasts.

7.43. On a group basis, for SSE, SP and CE, the allowances included in this paper are at or above the level of the companies' own forecasts. For CN and WPD, there are significant differences between their respective licensees, but the overall allowances are only slightly below the forecasts.

7.44. In the case of EDF and, to a lesser extent, UU there are significant differences. For both these groups, their forecasts show costs substantially higher than normalised 2002/03 levels. In each case, Ofgem's cost assessment teams and advisers have identified some areas of high costs (e.g. for UU, IT, procurement and property and, for EDF, corporate recharges). However, it is for company management rather than Ofgem to determine how best to achieve efficient cost levels.

Network Rates and pass through costs

7.45. The companies are faced with substantial increases in business rates on network assets in the next price control period. Ofgem has encouraged the companies to take all possible steps to minimise the scale of the increase and has no evidence to suggest that this has not been done. Rateable values have now been established and Ofgem proposes that business rates on network assets should now be treated as a pass through item. The values included for business rates in these proposals are unchanged from those in the September Update and are set out in table 7.3 below – any variations (whether positive or negative) from these values will be passed-through in the price control formula.

Table 7.3 Estimated DNO Business Rates 2005-10 (£ m, 2002/03 prices)

DNO	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m
CN - Midlands	23.4	22.2	21.1	20.5	20.5	20.5
CN - East Midlands	24.6	21.8	25.6	27.4	27.4	27.4
United Utilities	17.8	18.3	17.4	17.3	17.3	17.3
CE - NEDL	12.8	11.9	13.7	13.7	13.7	13.7
CE - YEDL	21.6	20.5	19.5	18.5	18.4	18.4
WPD - South West	16.3	14.4	16.9	18.2	18.2	18.2
WPD - South Wales	12.4	10.9	12.8	13.9	13.9	13.9
EDF - LPN	20.7	18.1	21.2	23.3	23.3	23.3
EDF - SPN	14.9	14.2	13.4	12.8	10.9	7.0
EDF - EPN	25.2	24.5	25.9	25.9	25.9	25.9
SP Distribution	24.7	28.4	33.4	33.4	33.4	33.4
SP Manweb	15.0	14.3	13.5	12.9	11.7	11.7
SSE - Hydro	8.3	9.5	11.2	13.2	14.7	14.7
SSE - Southern	34.1	30.2	35.5	38.0	38.0	38.0
Total	**271.8**	**259.1**	**281.2**	**289.0**	**287.2**	**283.4**

7.46. Licence fees payable to Ofgem are outside the companies' direct control and Ofgem has agreed that any variations in these licence fees from the amounts included in these proposals (set out in table A6 in Appendix 3) will be passed-through.

7.47. Ofgem has also indicated that it will pass through efficiently incurred out-of-market balancing costs of generation on Shetland. These proposals include an estimate of these costs of £7m per year in SSE-Hydro's opex allowance.

7.48. As part of the British Electricity Transmission & Trading Arrangements project (BETTA), Ofgem has consulted upon the recovery of those costs incurred as a result of the transition between the present wholesale electricity trading arrangements in Scotland and BETTA. It has been suggested that a proportion of those costs relating to the run-off arrangements for the Settlement Agreement for Scotland (SAS) should be recovered through distribution use of system charges. Ofgem proposes to determine an appropriate allowance for those costs to be recovered by the Scottish DNOs, which will be added to the price controls for those companies, once the consultation has closed in mid December 2004.

Conclusion

7.49. As shown in Table 7.4 below, Ofgem is now proposing controllable cost allowances of £759m compared to £755m in the September update, an increase of 0.5 per cent.

Table 7.4 Comparison of operating cost allowances in June Initial Proposals, September Update and Final Proposals (average 2005-10)

DNO	June Initial Proposals	Change	September Update	Change	Final Proposals
	£m	£m	£m	£m	£m
CN - Midlands	55	4	59	1	61
CN - East Midlands	60	4	64	1	65
United Utilities	52	3	55	3	58
CE - NEDL	40	3	43	(0)	43
CE - YEDL	48	5	52	(1)	52
WPD - South West	46	3	48	(1)	47
WPD - South Wales	37	3	40	(1)	40
EDF - LPN	47	3	51	1	52
EDF - SPN	47	3	50	1	52
EDF - EPN	76	7	83	(1)	82
SP Distribution	52	4	56	(0)	56
SP Manweb	43	4	47	(1)	46
SSE - Hydro	36	2	38	0	38
SSE - Southern	64	4	68	1	69
Total	**702**	**53**	**755**	**4**	**759**

Capital expenditure

7.50. In assessing the appropriate allowances for capital expenditure, Ofgem asked the companies to provide forecasts of their requirements for the next review period. As explained in the Initial Proposals paper, the capital expenditure plans put forward by the companies generally demonstrated a need to increase investment, but showed a wide variation in the scale of increase proposed. Ofgem has, with the assistance of the engineering consultants PB Power, reviewed the proposals put forward by each of the DNOs to ensure that the allowances set are appropriate and represent fair value for customers

7.51. To assist in this process Ofgem commissioned PB Power to review both the proposals submitted by the DNOs and also their capital expenditure during the current price control period. The approach, described in detail in the Initial Proposals paper, has involved a review of the proposals submitted by the companies together with the development of models for both load-related and non-load related expenditure to allow an assessment of the DNOs' requirements on a consistent basis. The process has involved three main visits to each of the DNOs and extensive subsequent discussions.

Base case capex

7.52. As explained previously, PB Power and Ofgem have assessed each company's capex requirements on a consistent basis to provide a view of what companies will need to spend to maintain current network performance and risk levels (the "base case").

7.53. The resultant views remain as set out in September.

Resilience and worst-served customers

7.54. In addition to the base case assessment of capital expenditure required to maintain network performance and a quality of service case, the DNOs were invited to provide an alternative case which sets out their own view of appropriate expenditure. These generally included proposals for expenditure to enhance quality of service, network resilience and/or service to worst-served customers and/or to address environmental issues such as undergrounding.

7.55. Allowances for quality of service improvements are discussed in Chapter 4 above.

7.56. On resilience, previous studies[27] have recognised that the first priority is to improve operational practices and in particular, vegetation management. As explained above, Ofgem has provided additional allowances for this activity.

7.57. For many of the projects or programmes of work proposed in the areas of resilience and worst-served customers, expenditures of over £1,000 per affected customer would be necessary to deliver significant benefits. This would raise issues of value for money and cross-subsidy. The schemes that involve the lowest costs per customer tend to deliver relatively little benefit or, in some cases, the benefits have not been quantified by the DNOs concerned.

7.58. Ofgem considers that the measures and incentives included in these proposals should allow a significant improvement in performance. The additional schemes proposed by the DNOs do not appear to provide sufficient value for money for customers to justify introducing a new layer of regulation to target expenditure in these areas. Simply increasing allowances (as the DNOs have requested) would not change the direct incentives to improve performance. Ofgem considers that the capital expenditure allowances being set as part of this price control are sufficient to cover necessary expenditure and it is for the companies to decide on their priorities for investment within the overall allowances set.

7.59. In addition to the main capex allowance shown in table 7.5 Ofgem is allowing DNOs to log up a small amount of capex in relation to undergrounding as explained in Chapter 4.

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[27] "Proposals for Improved Storm Performance for Electricity Distribution Networks", Report by the Network Resilience Working Group, November 2003 and "October 2002 Power System Emergency Post Event Investigation Overview Report", Department of Trade and Industry, December 2002.

ESQCR

7.60. In their forecasts DNOs included amounts they estimated would be required to comply with the latest Electricity Safety, Quality and Continuity Regulations (ESQCR). As explained in the September Update, while prompt action is required at any sites where there is immediate danger from a safety perspective, most costs are expected to be incurred after site surveys are concluded (i.e. from 2008). It is therefore not necessary to provide an ex ante allowance now, but the appropriate level of costs will be reconsidered in 2008 when the surveys are complete and the costs should be clearer. Adjustment mechanisms have been provided in the draft licence modifications to cover this issue.

7.61. In addition, Ofgem understands that the DTI intends to consult on possible changes to the ESQCR that could give rise to additional costs during the coming price control period. A similar adjustment mechanism to that proposed above has been provided in the draft licence modifications to give protection to DNOs against this risk in so far as any costs incurred are efficient.

Fluid Filled Cables

7.62. As noted in the Initial Proposals paper, Ofgem has commenced a separate dialogue with EDF on its proposed expenditure on the replacement of fluid filled cables. Ofgem has also requested information from all the DNOs on this issue.

7.63. While fluid-filled cables make up part of each of the DNO networks, it is clear that they represent a much larger proportion of the EDF-LPN network and that significant replacement of such cables would be a greater challenge for EDF than for other DNOs. The base case allowances set out above treat fluid filled cables in the same way as other assets and therefore include significant expenditure on these assets in some cases. Inclusion of additional allowances for environmental reasons has not yet been justified. However, Ofgem recognises that DNOs face a risk that additional expenditures will be required by 2010.

7.64. Ofgem will continue to consider this issue and will make proposals for the treatment of expenditure on replacement of fluid-filled cables once this work is complete. This will involve either additional allowances where appropriate or some arrangement to mitigate the risk of additional costs that DNOs would otherwise face.

Sliding scale mechanism

7.65. The Initial Proposals set out a possible development of the current regulatory framework ("sliding scale mechanism") to provide for a more flexible approach to capital expenditure, without disadvantaging those companies that have provided more reasonable forecasts. The operation of the sliding scale mechanism involves increases in capex allowances, which are set out here, and changes to incentives and revenues which are described in the following section ("Incentives").

7.66. Most companies supported the sliding scale mechanism in concept but have continued to argue for higher base capital expenditure allowances as well as the use of the sliding scale capex allowance.

7.67. Ofgem has decided to implement the sliding scale mechanism as described in the September Update and the allowances for capital expenditure have been set on that basis. However, Ofgem does not accept the arguments for higher base case allowances; the basis of the sliding scale is that the additional capex allowance is intended to provide scope for expenditures above the base case PB Power view.

7.68. Following discussions on the base case capital allowances and on the operation of the sliding scale mechanism, some DNOs have suggested that the inclusion of certain items of expenditure in their base case forecasts was inappropriate and have requested that these items should be removed from their forecasts. Ofgem has agreed to these proposals. These changes reduce the gap between the DNO's forecast and the PB Power view, which increases the incentive rate and the revenue adjustment, but reduces the sliding scale capex allowance.

7.69. Table 7.5 below sets out updated aggregate capex allowances (including capex allowances relating to quality of service but before adjustments in relation to pension costs). It also shows the DNOs' current estimates of total capital expenditure during the current review period and the Ofgem/PB Power view of the base case allowance.

Table 7.5 Comparison of capex allowance to forecast total 2005-10 (£m, 2002/03 prices)

DNO	Actual / forecast expenditure 2000-2005	Adjusted company base case forecast	PB Power view of DPCR4 capex (Base case)	Total allowance (excluding QoS)	Difference	Total allowance (including QoS)
	£m	£m	£m	£m	£m	£m
CN - Midlands	336	485	444	477	-8	501
CN - East Midlands	301	480	445	476	-4	485
United Utilities	347	457	439	466	9	466
CE - NEDL	228	268	263	277	9	277
CE - YEDL	242	358	346	367	8	371
WPD - S West	221	269	269	283	13	283
WPD - S Wales	191	171	171	179	8	186
EDF - LPN	260	536	398	452	-84	452
EDF - SPN	283	479	433	466	-13	487
EDF - EPN	438	745	609	674	-71	697
SP Distribution	253	375	335	361	-14	361
SP Manweb	240	455	363	404	-51	404
SSE - Hydro	165	208	189	204	-5	204
SSE - Southern	375	511	511	536	25	561
Total	**3882**	**5798**	**5216**	**5623**	**-175**	**5734**
Increase on 00-05		**49%**		**45%**		**48%**

Note:
In the above, the total allowance is the PB Power view plus sliding scale, see Appendix 3 for more details.
This excludes capitalised faults and non operational capex and the pensions adjustment.

7.70. This table shows that, for most groups (with the main exceptions being EDF and SP), capex allowances are in line with or above companies' base case forecasts. It also shows that the proposals will allow expenditure substantially in excess of the levels being undertaken in the current price control period. For EDF, the proposed allowances are 67% higher than they will have spent (on a comparable basis) in 2000-05. For SP, the proposed allowances are 55% higher than they will have spent in 2000-05.

Incentives

Sliding scale incentive mechanism

7.71. From an early stage in the review, Ofgem has highlighted and focussed on the challenges of regulating in an environment of increasing investment. The December 2003 document highlighted Ofgem's concerns about the treatment of DNO proposals for a significant increase in capex requirements against current capex allowances. It suggested that in the absence of clearly measurable outputs against which efficiency of spend could be judged, one way of offsetting the incentive for DNOs to game the bidding system was to link the savings incentive rate to the size of the capex allowance; a further idea was to provide a reward for companies with lower capex projections in order to reward their cost efficiency.

7.72. In subsequent consultations, these ideas were developed into a "sliding scale mechanism" that is intended to:

- retain an incentive for efficiency throughout;
- reduce the emphasis on Ofgem's or its consultant's view of the appropriate level of capex;
- reduce the perceived risk that the price control causes under-investment;
- allow but not encourage overspend (expenditure in excess of the "allowance");
- reduce the possibility of "high" capex companies making very high returns from underspend;
- reward the "low" capex companies if they deliver what they say; and
- avoid strong incentives to underspend by cutting corners and not delivering outputs or by storing up problems for subsequent periods.

7.73. The approach would, in principle, allow companies to choose between getting:

- ♦ a lower cost allowance, but with a "higher-powered incentive" that allows them to retain significant benefits if they can do even better than the low figure, and
- ♦ a higher allowance, but with a "lower-powered incentive" that gives relatively smaller reward for underspending the higher allowance.

7.74. In addition, companies that choose the low cost allowance get a reward (a small amount of additional return above the base cost of capital) for spending no more than their allowance, while companies that choose the high cost allowance do not (they are neither rewarded nor penalised if they spend their allowance). The aim is that companies who know they need to spend a lower amount of capex will find it more beneficial to choose the lower allowance, whilst companies who know they need to spend relatively more will find it more beneficial to choose the higher allowance (this property is known as being "incentive compatible").

7.75. The sliding scale matrix remains as set out in September and is replicated below. The efficiency incentive rates and allowed expenditure levels are linear functions of the ratio of the DNO's forecast to PB Power's view. The additional income is then adjusted to ensure the matrix remains incentive compatible.

7.76. This table has been used to derive the allowances in table 7.5 above and to derive additional returns and incentive rates as set out in table 7.7 below.

Table 7.6 Sliding scale matrix

DNO:PB Power Ratio	100	105	110	115	120	125	130	135	140
Efficiency Incentive	40%	38%	35%	33%	30%	28%	25%	23%	20%
Additional income	2.5	2.1	1.6	1.1	0.6	-0.1	-0.8	-1.6	-2.4
as pre-tax rate of return	0.200%	0.168%	0.130%	0.090%	0.046%	-0.004%	-0.062%	-0.124%	-0.192%
Rewards & Penalties									
Allowed expenditure	105	106.25	107.5	108.75	110	111.25	112.5	113.75	115
Actual Exp									
70	16.5	15.7	14.8	13.7	12.6	11.3	9.9	8.3	6.6
80	12.5	11.9	11.3	10.5	9.6	8.5	7.4	6.0	4.6
90	8.5	8.2	7.8	7.2	6.6	5.8	4.9	3.8	2.6
100	4.5	4.4	4.3	4.0	3.6	3.0	2.4	1.5	0.6
105	2.5	2.6	2.5	2.3	2.1	1.7	1.1	0.4	-0.4
110	0.5	0.7	0.8	0.7	0.6	0.3	-0.1	-0.7	-1.4
115	-1.5	-1.2	-1.0	-0.9	-0.9	-1.1	-1.4	-1.8	-2.4
120	-3.5	-3.1	-2.7	-2.5	-2.4	-2.5	-2.6	-3.0	-3.4
125	-5.5	-4.9	-4.5	-4.2	-3.9	-3.8	-3.9	-4.1	-4.4
130	-7.5	-6.8	-6.2	-5.8	-5.4	-5.2	-5.1	-5.2	-5.4
135	-9.5	-8.7	-8.0	-7.4	-6.9	-6.6	-6.4	-6.3	-6.4
140	-11.5	-10.6	-9.7	-9.0	-8.4	-8.0	-7.6	-7.5	-7.4

where, for example: (top-left corner) 16.5 = (105 – 70) x 40% + 2.5

(bottom-right) -7.4 = (115 – 140) x 20% - 2.4

7.77. Each company will be positioned in a particular column of this matrix as part of the price review. Actual capex will then determine the row.

7.78. The incentive rates proposed for each DNO are given in table 7.7 below.

7.79. In response to the September Update, the EDF and SP companies have asked Ofgem to change their "DNO forecast" to reflect previous discussions and new information on the capex forecasts. After review by Ofgem and PB Power it has been agreed that certain items should not be included in the base case and should be excluded from the forecasts initially submitted for the purposes of comparison. The effect of these changes is included in the tables in this section and in the Final Proposals.

Table 7.7 Sliding scale income and incentive rates

DNO	Ratio of DNO forecast to PBP view	Group ratio	Sliding scale factor	Capex allowance	Additional return	Incentive rate
CN - Midlands	109%	108%	107%	477	0.142%	36%
CN - East Midlands	108%	108%	107%	476	0.142%	36%
United Utilities	104%	104%	106%	466	0.175%	38%
CE - NEDL	102%	103%	105%	277	0.183%	39%
CE - YEDL	103%	103%	106%	367	0.183%	39%
WPD - S West	100%	100%	105%	283	0.200%	40%
WPD - S Wales	100%	100%	105%	179	0.200%	40%
EDF - LPN	135%	122%	114%	452	0.022%	29%
EDF - SPN	111%	122%	108%	466	0.022%	29%
EDF - EPN	123%	122%	111%	674	0.022%	29%
SP Distribution	112%	119%	108%	361	0.057%	31%
SP Manweb	125%	119%	111%	404	0.057%	31%
SSE - Hydro	110%	103%	107%	204	0.183%	39%
SSE - Southern	100%	103%	105%	536	0.183%	39%
Total	111%	111%	107.8%	5623	0.12%	34%

7.80. The additional return and incentive columns are based, for each DNO group, on the ratio of their capital expenditure forecast to the total Ofgem/PB Power base case view for the DNOs in the relevant group. This approach is intended to avoid giving perverse incentives between companies in the same ownership group. If the ownership of any DNO changes after the review concludes, consideration would need to be given to which rates to use – the default option will be to use the lowest rate applying to any of the merging companies prior to the transaction for all companies in the new group.

7.81. The sliding scale incentive rates will be given effect through adjustments to the capex rolling incentive mechanism. Appendix 1 includes an example of how Ofgem intends this would be applied in practice.

7.82. The sliding scale mechanism has been a useful part of the review and it is encouraging that it has led some of the companies with the biggest gap between their forecast and PB Power's view to rethink their own forecast. However, the real test will clearly occur over the next few years and Ofgem will assess the position at the next review before deciding whether to continue with a sliding scale mechanism. Nonetheless, some points bear emphasis:

- Ofgem has not disallowed any specific expenditure or projects – allowances have been set which, in Ofgem's view, should be sufficient to allow the companies to maintain their networks and improve quality of supply. It is for companies to prioritise and to decide on the levels of investment they need to undertake;

- Companies' expenditure in the coming period will be important evidence at the next review – customers should not be expected to fund investment twice, or to fund a backlog or catch-up programme where companies have profited by creating the backlog; and

- Ofgem will continue to develop thinking on total cost analysis and will want to continue to encourage capital expenditure efficiency as well as operating cost efficiency.

Opex incentives

7.83. Ofgem has noted that due to the differential in incentive rates between opex and capex, and the absence of a robust and prescriptive scheme for the classification of costs, there is an incentive for distributors to capitalise costs. This may be a reason for a variety of accounting treatments being applied by distributors to what are essentially the same categories of costs. Consequently, both Ofgem and the distributors have had to apply significant resources to derive a consistent set of operating costs across distributors as a basis for determining opex allowances through the use of benchmarking techniques.

7.84. In the Initial Proposals document, Ofgem noted that it was not appropriate that DNOs continued to benefit, potentially at the expense of consumers, from unclear cost boundary issues and from delivering apparent "efficiency savings" through reclassifying costs. Accordingly, Ofgem proposed to treat all costs on the same basis for the purpose of determining the incentive payment companies would receive for achieving efficiency savings in the next price control period; i.e. that the strength of incentives for all categories of efficiency savings would be equalised (at the level applicable to capex savings).

7.85. The majority of respondents were strongly opposed to this weakening of the overall incentive rate. Several DNOs considered that the work conducted during the opex normalisation process had sufficient clarity to enable a robust set of cost definitions to be established, thereby overcoming the problems of inappropriate categorisation of costs. On this basis, they proposed that the current regime with differential incentives should be allowed to continue in the next price control period.

7.86. Ofgem agrees with the views of several respondents that the most important response to this issue is to establish a new cost reporting process which addresses these difficulties. Ofgem is fully committed to this project and has received commitments from senior management in all of the DNOs that they support the development of a robust set of cost categorisation guidelines within the timeframe proposed (set out in Chapter 2 above) and that they will both fully co-operate with, and adequately resource, the working group(s) that will be established to develop these cost reporting guidelines. These cost reporting guidelines will be detailed and prescriptive.

7.87. In view of the representations made by respondents, Ofgem will continue with the traditional differential incentives applied to opex and capex while the cost reporting project is progressed. However, if, by the time of the next review, Ofgem is not fully satisfied that a robust scheme for categorisation of costs is in place and being implemented by all DNOs, then any DNO that has not adequately supported the cost reporting project should expect any (positive) benefit that it has gained from incentives not being equalised to be reversed. This could be achieved through application of a rolling adjustment to have the effect of equalising opex and capex incentives with effect from 1 April 2005.

8. Financial issues

Introduction

8.1. This Chapter sets out Ofgem's final proposals on a number of issues for this review:

- 2004/05 revenues;
- Regulatory Asset Value (RAV);
- depreciation and asset lives;
- pensions;
- the cost of capital;
- tax;
- financial indicators;
- financial modelling; and
- the financial ring-fence.

2004/05 revenues

8.2. Initial price changes ("P0's") are normally presented as the difference between price controlled revenue in the final year of the previous price control period and the first year of the new period (in this case, 2004/05 and 2005/06 respectively). The September Update explained that, in a number of cases, the DNOs had provided Ofgem with updated revenue forecasts for 2004/05. These changes had an impact on the P0 adjustments but made no difference to the proposed revenue allowances for 2005/06 to 2009/10. Since that paper it has become clear that, in some cases, a further adjustment is necessary to exclude the impact of the "merger tax" from the 2004/05 revenue for consistency with the presentation of allowances for 2005/06 and thereafter. The effect of these adjustments is shown in table 8.7.

Regulatory asset value to 2005

8.3. The regulatory asset value (RAV) is a measure of the value of the capital employed in the regulated business, based on historical investment costs, on which the companies earn a return and receive depreciation. The RAV is widely used by the financial markets to assess value for both debt and equity investors and it is therefore important that it is calculated on a consistent basis between companies and over time.

8.4. The RAV at 31 March 1998 was established as part of the last price control review. Rolling this forward to 2005 should simply be a matter of adding actual capital investment and adjusting for depreciation and inflation. However, companies have different ways of accounting for past capital expenditure (investment) and in many cases these have varied over time – for example changing the amount or proportion of overheads allocated to capital expenditure. In principle, it is appropriate to roll forward the RAV on the same calculation basis as used to set the last price control. In practice this has proven difficult.

8.5. The September Update detailed the adjustments that Ofgem had made to the RAV values proposed by the companies. Since September Ofgem has made some small further changes to the RAV values to correct certain calculations.

8.6. The impact of these changes is shown in the table below.

Table 8.1 RAV values at 31 March 2005 (£ m, 2002/03 prices), prior to separation of metering

	Initial Proposals	Indirect cost adjustment	Margins	Faults	03/04 act capex & 04/05 fcst	Other adjusts (Note 1)	**September Update**	Changes to adjustments (Note 2)	**Final Proposals**
CN - Midlands	**951**	0	-	22	19	(11)	**981**	-	**981**
CN - East Midlands	**958**	(8)	-	-	7	6	**963**	3	**966**
Unitied Utilities	**881**	6	(1)	20	37	(3)	**940**	1	**941**
CE - NEDL	**574**	17	16	12	9	(19)	**609**	3	**612**
CE - YEDL	**820**	7	4	(5)	2	(8)	**820**	0	**820**
WPD-South West	**733**	(17)	(0)	(9)	14	(9)	**711**	-	**711**
WPD-South Wales	**587**	-	0	(10)	7	2	**586**	-	**586**
EDF - LPN	**941**	(7)	(24)	23	(3)	(12)	**918**	10	**928**
EDF - SPN	**666**	(1)	(10)	(9)	8	(0)	**653**	3	**656**
EDF - EPN	**1,179**	(30)	(6)	31	(11)	(10)	**1,153**	12	**1,166**
SP Distribution	**1,311**	(60)	5	2	0	(3)	**1,255**	1	**1,255**
SP Manweb	**762**	(40)	2	2	32	(7)	**750**	-	**750**
SSE - Hydro	**736**	-	(1)	3	4	(6)	**737**	0	**737**
SSE - Southern	**1,350**	(5)	(1)	20	7	(6)	**1,364**	-	**1,364**
Total	**12,446**	(138)	(16)	102	133	(87)	**12,439**	33	**12,473**

Note

1 Other adjustments include non-operational depreciation, adjustments to pension costs on a cash basis and movement in depreciation.

2 Main changes are for LPN,SPN & EPN relating to the internal margin adjustment.

8.7. As can be seen from the above table the most material changes since the September Update Paper relate to EDF. These changes reflect a correction to the treatment of the margins on intra-group charges.

8.8. The RAV calculations presented here rely on the DNOs' own forecasts of 2004/05 capital expenditure. In the event that actual 2004/05 RAV additions turn out to be materially different to the estimate used, Ofgem would not expect to alter revenue in the period 2005-10 but if the difference is not due to genuine efficiencies that could not reasonably have been foreseen at the time the forecast was provided, Ofgem may decide to claw back the benefits of any under-spend against the estimate used at the next review.

8.9. In future, it is Ofgem's intention that cost information should be collected more regularly so that RAV calculations do not need to be revisited for reasons of cost definition. Appendix 1 discusses the RAV calculations for the period to 2010.

Deprecation, asset lives and capitalisation

8.10. At the last price control review, some companies would have seen a large reduction in their depreciation allowance as Vesting assets[28] became fully depreciated (the so called depreciation "cliff-face"). An adjustment was made to smooth the depreciation allowance and a similar approach is proposed for this review.

8.11. This adjustment involves switching to a shorter asset life for post-Vesting assets (from 33 to 20 years) once Vesting assets are fully depreciated. In order to ensure companies are neutral to this switch in NPV terms it is also necessary to make an adjustment for the different values implied by the different lives. The difference between asset values using 33 and 20 years is calculated and added to depreciation spread over 15 years in equal instalments. Over the next price control period, most of the DNOs will see Vesting assets fully depreciated, and as this occurs, the smoothing adjustment has been applied. The exceptions are SP Distribution and SSE-Hydro (the two Scottish DNOs), where the privatisation values were calculated on a different basis and Vesting assets have a longer asset life, and the three companies (United Utilities, WPD-South Wales and EDF-SPN) where the adjustment was applied at the last price control review.

8.12. Table 8.2 shows the assumed lives for Vesting assets.

[28] Vesting assets comprise all assets held by the business at Vesting (i.e. legal changeover for privatisation), valued based on flotation values.

Table 8.2 Vesting asset lives

DNO	Assumed Vesting asset life	Depreciation smoothing applied
CN – Midlands	15	from 2006/07
CN – East Midlands	15	from 2006/07
United Utilities	11	from 2002/03
CE – NEDL	14	from 2005/06
CE – YEDL	15	from 2006/07
WPD – South West	15	from 2006/07
WPD – South Wales	11	from 2002/03
EDF – LPN	15	from 2006/07
EDF – SPN	13	from 2004/05
EDF – EPN	14	from 2005/06
SP Distribution	20	n/a this price control period
SP Manweb	15	from 2006/07
SSE – Hydro	20	n/a this price control period
SSE – Southern	15	from 2006/07

Note: The years shown in the table represent the first year that a 20 year asset life and the smoothing adjustment are used.

8.13. In the longer term, it would be reasonable to expect the price control treatment of long-lived assets to more closely approximate to their useful technical or economic lives, for example so that the customers that pay for an asset are those that derive benefit from it. Were it not for the peculiarities of pre-vesting asset lives and the need to maintain broadly stable financial profiles, it seems unlikely that 20 year lives would be optimal. Ofgem will want to review this issue at the next review in the light of these considerations.

8.14. In the September Update paper, Ofgem capitalised (i.e. transferred into the RAV from 2005 onwards) 26 per cent of the basic operating cost allowances (including all fault and non-operational capex) from the regression analyses. However, the additional allowances for tree-cutting, quality of service and exceptional events were treated as 100 per cent opex. This distinction would risk complicating the future RAV roll forward unnecessarily. To avoid this and to make the roll forward of the RAV and comparison with opex allowances as straightforward as possible, these final proposals treat all these costs in the same way, capitalising a constant percentage. In order to ensure that this change does not have an adverse effect on cash flows, the overall capitalisation percentage has been revised to 23.5%. The effect of these adjustments is that £178m of total opex is capitalised compared to £179m in the September Update proposals. Capitalisation of pension costs into the RAV is discussed below.

Pensions

General

8.15. In the Initial Conclusions to the Developing network monopoly price controls project, published in June 2003, Ofgem set out the principles it would apply in relation to the treatment of pension costs. The key points are:

- Consumers of network monopolies should expect to pay the efficient cost of providing a competitive package of pay and other benefits, including pensions, to staff of the regulated business, in line with comparative benchmarks;

- In principle, each price control should make allowance for the ex ante cost of providing pension benefits accruing during the period of the control, and similarly for any increase or decrease in the cost of providing benefits accrued in earlier periods resulting from changes in the ex ante assumptions on which these have been estimated;

- Pension costs should be assessed using actuarial methods, on the basis of reasonable assumptions in line with current best practice;

- Increases or decreases in the future costs of providing accrued benefits resulting from under- or over-funding in prior periods will need to be considered on a case-by-case basis;

- Increases or decreases in the future costs of providing accrued benefits resulting from differences between ex ante and ex post investment returns in prior periods will also need to be considered on a case-by-case basis;

- Liabilities in respect of the provision of benefits that do not relate to the regulated business should not be taken into account in assessing the efficient level of costs for which allowance is made in the price control; and

- Companies will also be expected to absorb any increase (and may retain the benefit of any decrease) in the cost of providing enhanced pension benefits granted under severance arrangements which have not been fully matched by increased contributions.

8.16. Since June 2003, Ofgem has discussed its approach with the companies and other interested parties and has developed its proposals. The September Update included allowances for pension costs based on the latest information available at the time, assuming that, for most DNOs, 80 per cent of the deficit was attributable to distribution, disallowing 30 per cent of unfunded Early Retirement Deficiency Costs (ERDCs) and spreading the remaining deficit over 13 years. The proportion allocated to distribution and the treatment of ERDCs were both intended to represent a pragmatic approach in the circumstances, particularly reflecting that the appropriate treatment of pension fund deficits had not been an issue considered at previous reviews.

8.17. These proposals incorporate the latest information provided by the DNOs based on the most recent actuarial valuations and actuarial forecasts of contribution rates for both normal contributions and deficit recovery. Of total pension deficits of £1,493m (in 2002/03 prices) at 31 March 2004, £1,209m has been allocated to distribution. After deduction of disallowed ERDCs £1,071m will be funded through the price control. This gives an annual allowance for deficits of £123m. In addition, approximately £85m per annum is being allowed to cover future service costs ("normal costs"). Details of the allowances for each DNO are set out in Appendix 3.

Allocation to distribution

8.18. The September Update Paper proposed a pragmatic approach of assuming 80 per cent of scheme deficits related to the distribution business except in the cases of:

- EDF-EPN and CE-YEDL, where 100 per cent of the deficit was allocated to distribution since only liabilities relating to the active distribution members were transferred when the businesses were acquired by the current owners; and
- SSE-Hydro and SP Distribution, where the figure would have been lower because their schemes include generation employees, but the calculation was not required for this review because their schemes are not in deficit.

8.19. While some DNOs accepted this pragmatic approach as a sensible compromise, others have argued for a greater allocation to distribution in their own cases. Ofgem remains of the view that this pragmatic approach is reasonable, given the arbitrary assumptions that would have to be made in order to estimate a specific percentage for each DNO.

ERDCs

8.20. Some companies have argued against Ofgem's proposals to split the cost of early retirement deficiency contributions (ERDCs) between customers and shareholders on a 70:30 basis. They have argued either that the company share should be significantly less than 30 per cent or that it was wrong in principle that the shareholders should pay any of the cost. While there are some reasonable arguments why the company's share might be less, the September Update also set out more compelling reasons why a higher share could be justified. Ofgem remains of the view that the 70:30 split is an appropriate basis for sharing these costs between customers and shareholders in order to reinforce the low risk position of DNOs.

8.21. The costs of ERDCs from 1 April 2004 will be a matter for shareholders, as set out in the principles above.

Deficit allowance

8.22. In the September Update Paper Ofgem disallowed 1/13th of the deficit at 31 March 2004 on the basis that it should be covered by deficit contributions made during 2004/05. The DNOs pointed out that because final figures for the level of the deficit and for the contributions required to address that deficit would not be agreed by the scheme trustees until quite late in 2004/05, companies would not normally expect to start making those contributions until April 2005. They argued that it was therefore inappropriate to make any deductions to reduce the allowed deficit for assumed contributions in 2004/05 as deficit contributions were not allowed in the current price control. Ofgem has accepted these arguments and, in these Final Proposals, no deductions have been made for assumed deficit contributions in 2004/05. In most cases the deficit has been spread over 13 years (on an annuitised basis) which is the average remaining service life across all DNOs. The exception is EDF-SPN which has a materially lower average remaining service life. In this case, the actual average remaining service life of 10 years has been applied.

8.23. In setting proposed revenue allowances in the September Update, Ofgem capitalised 57.7 per cent of total pension costs. This reflected the average level of capitalisation of employment costs across the DNOs. A number of DNOs have argued against capitalising a proportion of pension costs relating to existing deficits, stating that this extended the period over which these deficits would be funded beyond the timescales in which the scheme trustees would require the relevant contributions to be made. They also argued that they were unlikely to be able to capitalise the deficit contributions in their accounts. One DNO accepted that capitalising a proportion of the deficit was a reasonable approach providing the DNOs were allowed an appropriate cost of capital.

8.24. Ofgem has considered these issues but considers that capitalising a proportion of total pension costs is a reasonable approach. The companies will earn a return equal to the allowed cost of capital on the costs capitalised and included in the RAV and will therefore be in a position to finance any mismatch of timing between contributions and allowed revenues. Ofgem has therefore decided to continue with the approach used in the September Update.

Normal pension costs

8.25. The allowance for normal pension costs (i.e. the pension costs relating to service during 2005-10 and excluding deficit funding) has been calculated by taking the DNOs' forecasts of future pensionable salaries for the distribution business (including related party service providers working on distribution), adjusting for the extent to which Ofgem's allowances for capex and opex differ from the DNOs' forecasts, then applying the latest estimates of the contribution rate for future normal service, as advised by the scheme's actuary.

Adjustment mechanism

8.26. While the proposed pension allowances are based on the best view currently available of the costs the DNOs will face, it is likely that, as a result of changing circumstances and the uncertainty in the assumptions underlying the proposed allowances, the contributions the companies make in practice will differ from these projections. Ofgem proposes to use an adjustment mechanism to accommodate such changes and thus reduce the risk associated with uncertainty in future pension costs.

8.27. The proportion of the deficit allowed in the distribution price control can be calculated as (deficit x distribution% - ERDCs disallowed)/deficit. For example, if the deficit is £100m, the distribution share 80 per cent and the disallowed ERDCs relating to distribution are £20m, then the allowed proportion will be (100 x 0.8 - 20) / 100 = 60 per cent. The allowed proportions are set out in table 8.3 below for each DNO.

8.28. The basis on which pension allowances in this review have been proposed is that, to the extent that the amount of normal contributions for distribution employees (including related party employees working on distribution, but excluding metering for this purpose) plus the total deficit contribution from the group multiplied by the allowed proportion differs from the allowance, the difference will be offset against any future pension costs in determining future pension allowances. In other words, if actual pension contributions, adjusted as described, exceed the allowance, the company will be allowed to recover the additional contribution in the next price control period, and vice versa. Any ERDCs incurred after 1 April 2004 will be for the cost of shareholders – this could be given effect by increasing the deemed allowances for 2005-2010 by the amounts of any unfunded ERDCs in 2004-2010.

Table 8.3 Allowed proportion of pension deficit

DNO	Proportion allowed
CN - Midlands	64%
CN - East Midlands	66%
United Utilities	66%
CE – NEDL	71%
CE – YEDL	95%
WPD - South West	61%
WPD - South Wales	69%
EDF – LPN	75%
EDF – SPN	68%
EDF – EPN	100%
SP Distribution	n/a
SP Manweb	79%
SSE – Hydro	n/a
SSE - Southern	76%

Note: SP Distribution and SSE – Hydro are not applicable because their pension schemes were not in deficit.

8.29. Pension allowances and contributions will not impact on the rolling incentive arrangements for capex (i.e. the arrangements will apply to capex net of pension costs or allowances). To the extent that the difference between actual contributions and allowances would affect RAV, this will be reversed so that neither customers nor shareholders are affected in NPV terms.

8.30. Table 8.4 shows the impact of the various changes made to total pension cost allowances since the Initial Proposals. The main changes since the September Update are set out in Appendix 3.

Table 8.4 Summary of the Changes to Pension Allowances Since Initial Proposals

Average Annual Pension Allowance	June Initial Proposals	September Update	Final Proposals
	£m	£m	£m
CN - Midlands	**6.2**	**15.6**	**16.2**
CN - East Midlands	**9.3**	**13.6**	**13.1**
United Utilities	**7.4**	**13.8**	**16.0**
CE - NEDL	**5.2**	**17.0**	**17.7**
CE - YEDL	**6.2**	**8.9**	**10.5**
WPD - South West	**8.6**	**14.6**	**14.8**
WPD - South Wales	**5.5**	**10.3**	**10.2**
EDF - LPN	**15.3**	**20.0**	**21.9**
EDF - SPN	**7.4**	**14.5**	**20.6**
EDF - EPN	**9.7**	**10.3**	**12.5**
SP Distribution	**4.7**	**4.6**	**4.8**
SP Manweb	**11.9**	**15.2**	**15.7**
SSE - Hydro	**3.4**	**3.3**	**3.9**
SSE - Southern	**18.4**	**28.0**	**30.2**
TOTAL	**119.2**	**189.7**	**208.2**

Note The above figures are calculated on the basis of average annual allowances over the five years of the price control, so will differ slightly from the comparable table in the September Update which showed amounts based on the first year of the control (2005/06).

Cost of capital

8.31. The cost of capital is the return required by the financial markets – both debt and equity – to provide capital to a firm. The cost of capital is a key input when determining the price control for a capital intensive business.

8.32. For the reasons set out in the March 2004 Policy document, Ofgem has used a post-tax approach to the cost of capital. Background information on the methodology and the inputs to the cost of capital was published in an appendix to the March 2004 document. The underlying data indicated a range from 3.0 per cent to 5.0 per cent for the post-tax real cost of capital, given the uncertainty surrounding some of the key market inputs. Faced with this wide range of possible values for the cost of capital, and given the investment focus of this review, Ofgem decided to exclude the lower end of this range from consideration and consulted on a range from 4.2 per cent to 5.0 per cent.

8.33. For the June Initial Proposals and the September Update, Ofgem adopted a point estimate of 4.6 per cent for the post-tax real cost of capital, which was the midpoint of the range proposed in March. Ofgem pointed out that this was a 'modelling assumption' and did not represent a decision on the appropriate cost of capital; this decision would be made as part of the Final Proposals in November.

8.34. A wide range of parties have commented on Ofgem's cost of capital proposals in responses to the various consultation documents. Ofgem has responded to key points made by respondents in the June and September Summary of Responses documents in addition to the main documents.

8.35. The majority of respondents to the September Update argued that Ofgem's post-tax real cost of capital estimate of 4.6 per cent was too low. It was argued that Ofgem should adopt a value for the cost of capital at least at the top end of the range set out in March.

8.36. The main argument has been by comparison with OFWAT, which proposed a post-tax cost of capital figure of 5.1% in its draft determinations in August 2004[29]. The DNOs and investors have also argued that they have competing uses for capital which offer more attractive risk-adjusted returns and that too low a cost of capital figure would therefore result in under-investment in the electricity distribution sector. Where the comments have related to a specific component of the cost of capital, they have focussed on the view that the cost of equity assumed for modelling purposes in the Initial Proposals and the September Update would be too low to attract equity investment in the distribution businesses.

8.37. One non-DNO respondent argued that current market data points to a lower cost of capital figure and that there was no compelling evidence to adopt a higher figure than the modelling assumption adopted for the June Initial Proposals.

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[29] Ofwat (August 2004), Future water and sewerage charges 2005-10 Draft determinations, Periodic review 2004

8.38. In forming a view on the appropriate cost of capital estimate to use in the Final Proposals, Ofgem has considered a range of arguments and factors, including:

- the overall balance of risk which DNOs will face given the price control treatment of each of the significant elements of cost (opex, tax, capex) and the likely volatility of these costs compared to Ofgem's central estimates;
- the extent to which DNOs can control their costs through management action;
- the mechanisms for dealing with unanticipated costs arising in the future;
- the expected amount of capital investment in relation to the scale of the business (i.e. operational gearing);
- the capital structure of the industry (as measured by the average or 'typical' company);
- the amount of investment DNOs will have to make to deliver required outputs;
- the extent to which funds will be generated internally and the amount of new external finance required (including refinancing of existing obligations);
- the competition for capital within the businesses;
- the likely market conditions (supply, price and risk appetite) in which external financial requirements must be met and the risks around these;
- the competing demands that will be placed on financial markets from other sources;
- the expectations of capital providers (which are shaped, in part, by relevant regulatory precedent), and
- importantly, the desirability of enabling companies to earn predictable returns over the life of their assets (i.e. assuming constant macro-

economic conditions, baseline real returns should be broadly stable over time).

Main components of the cost of capital

8.39. The Weighted Average Cost of Capital (WACC) is the weighted average of the *expected* cost of equity and the *expected* cost of debt. The three main components are therefore (i) the expected cost of equity; (ii) the expected cost of debt; and (iii) the gearing assumption.

The expected cost of equity

8.40. One of the main objectives in setting the cost of capital for this review is to facilitate the necessary capital formation (debt and/or equity) to enable the expected investment to take place.

8.41. Several companies have argued that Ofgem's cost of capital figure should be sufficient to allow companies to attract and retain equity funding. It was argued that too low a cost of capital figure could result in a flight of equity as seen in the water sector in 1999. It was also argued that, following OFWAT's draft determinations, there are significantly higher returns available in the water sector and that this is likely to result in an exit of equity from the UK electricity sector over the next five years.

8.42. In determining its cost of equity assumption for the final proposals Ofgem has had regard to traditional methods such as CAPM as well as wider market evidence, including data on the aggregate return on equity over time. As part of this review, Ofgem commissioned Smithers & Co to present a report on beta estimates for a range of companies in the electricity and water sectors[30]. Smithers & Co found strong evidence of parameter instability for several of the companies. This was problematic given that a fundamental assumption

[30] Wright, S.(Birkbeck College) and Smithers & Co (March 2004), Beta Estimates for: Scottish Power, Scottish & Southern Energy, Viridian Group, Centrica, International Power, National Grid Transco, United Utilities, Kelda Group, Severn Trent. This study is available at the Ofgem website.

underlying the traditional CAPM approach is that beta remains stable over time. The report presented two possible interpretations of the data in this situation:

- beta estimates are more uncertain and hence more weight might be given to a beta assumption of 1 (i.e. the beta of the average firm); or
- markets are 'learning' about the companies and the regulatory regime and hence parameter instability is mainly an issue early in the sample.

8.43. Given this background, Ofgem decided also to have regard to other methods in determining the appropriate cost of equity, most notably an aggregate return on equity approach as proposed by Smithers & Co[31]. The Smithers & Co report for the joint regulators group argues that, in situations where there is considerable uncertainty with respect to the key inputs to the cost of equity, an aggregate return on equity approach might be more appropriate. Ofgem has also carefully considered the responses to its proposals, including those from investors and other market commentators.

8.44. Ofgem notes that the Smithers & Co report for the joint regulators group concludes that their "central estimate of the cost of equity capital, derived from a wide range of markets, is around 5.5% (geometric average), and thus 6.5% to 7.5% (arithmetic average)".[32]

8.45. For these Final Proposals, given the investment focus of the review, Ofgem has adopted a post-tax real cost of equity figure of 7.5 per cent for these Final Proposals. This is the top end of the range published in the March 2004 Policy Document and is 25 basis points higher than the figure used for modelling purposes in the Initial Proposals. This figure compares with a post-tax cost of equity of 6.0 per cent at the last price control review. In Ofgem's view, this will not restrict companies from financing investment through an appropriate mix of debt and equity, thus maintaining an appropriate and sustainable capital structure.

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[31] Wright, S., Mason, R. and Miles, D. (2003), A Study into certain aspects of the cost of capital for regulated utilities in the UK, Smithers & Co Ltd
[32] Page 4

Cost of debt

8.46. In the Initial Proposals, Ofgem adopted a pre-tax cost of debt figure of 4.1 per cent. This figure reflected the considerable uncertainty surrounding the *expected* cost of debt.

8.47. In the March 2004 Cost of Capital appendix, Ofgem noted that both the debt premium and risk free rate had decreased in recent years and hence it proposed a slightly lower figure for the expected cost of debt compared with the last price control review. Ofgem also noted that the current debt premium, especially for DNO's UK debt, seemed to be relatively low and that it was possible that this was due to increased demand for corporate debt by investment institutions, particularly pension funds. Also, it had been argued that yields on government bonds were at historically low levels. In setting the cost of capital modelling assumption for Initial Proposals, Ofgem therefore used a cost of debt figure above that implied by current market rates.

8.48. Ofgem notes that there has been a small increase in the average debt premium since its Initial Proposals. However, even this increased debt premium is still below the level assumed in the pre-tax cost of debt used in the Initial Proposals. Ofgem also notes that the yield on short-term (e.g. five year) index-linked government bonds has increased slightly, whereas the yield on long-term (e.g. 20 year) index-linked government bonds has decreased slightly.

8.49. In the light of these considerations, Ofgem has decided that the appropriate assumption for the pre-tax real cost of debt in these Final Proposals is 4.1 per cent. This decision reflects the fact that companies may need to raise a combination of debt and equity finance in order to fund their investment programmes.

Gearing

8.50. The other key input to the WACC is the gearing assumption (defined, for regulatory purposes, as the ratio of net debt to RAV). In order to set an industry wide cost of capital Ofgem has to adopt the same gearing assumption for all the DNOs. The June 2004 Initial Proposals were based on gearing of 60 per cent compared with an assumption of 50 per cent at the last price control review.

8.51. Ofgem has noted that the average gearing level at licensee level has increased since the last price control. However, the gearing levels of the DNOs vary considerably.

8.52. Having considered the available evidence and the anticipated financing requirements of the companies, Ofgem has decided to adopt an assumed gearing level of 57.5 per cent. This is based on a judgment with respect to both the actual gearing level and the projected gearing level, and has given consideration to the levels of upstream guarantees given by licensees.

8.53. Ofgem's gearing assumption should not be interpreted as an endorsement of any particular capital structure. In Ofgem's view, the companies and their financiers are best placed to decide on the most appropriate capital structure.

Pre-tax, post-tax and 'Vanilla' WACC

8.54. In March 2004 Ofgem decided to adopt a post-tax approach to the cost of capital.

8.55. At previous reviews, Ofgem adopted a pre-tax cost of capital. In the pre-tax approach, Ofgem provided for tax liabilities through an allowance in the pre-tax cost of capital. A post-tax approach requires the tax allowance to be calculated separately and refers to the cost of capital net of all tax.

8.56. In practical terms, when a post-tax cost of capital is being used the price control calculations require specific estimates of tax costs plus a pre-tax return on debt and a post-tax return on equity. The related cost of capital figure, which does not incorporate any tax adjustment (i.e. neither to the cost of equity nor to the cost of debt) is referred to as the 'Vanilla' WACC.

Overall cost of capital

8.57. The allowed cost of capital under the existing price control (on a pre-tax real basis) is 6.5 per cent.

8.58. The table below sets out the cost of capital used in these Final Proposals, compared to the mid point of the range used in Initial Proposals and the September Update.

Table 8.5 Cost of capital assumptions

	Mid-point (Initial Proposals and September Update) (per cent)	Final Proposals (per cent)
Cost of debt	4.1	4.1
Cost of equity	7.25	7.5
Gearing	60	57.5
Vanilla WACC	5.4	5.5 [33]
Post-tax	4.6	4.8
Pre-tax*	6.6	6.9

* based on a traditional tax wedge approach; compares to 6.5 per cent in the previous Electricity Distribution price control review and 6.25 per cent in the last Transco price control review; equivalent to approximately 8 per cent taking account of actual tax allowances proposed.

Tax

8.59. Ofgem has historically provided for tax liabilities through an allowance in its estimate of the pre-tax cost of capital. However, Ofgem has decided to use a post-tax approach to the cost of capital (calculating tax allowances separately) for this price control review, in order to:

- reflect the change to the Inland Revenue's treatment of network capital expenditure, which is expected to increase effective tax rates for most companies;
- improve consistency with other aspects of the regulatory framework, in which changes in the level of costs are passed on to consumers at the subsequent price control review; and
- reduce the incentives to increase gearing.

8.60. Overall, the tax allowances proposed in this review reflect the higher expected tax liabilities resulting from the ending of the non-load agreement with the

Inland Revenue which allowed most of the DNOs to claim 100 per cent allowances on a significant proportion of their non-load related capital expenditure treated as deferred revenue by the Inland Revenue. DNOs have informed Ofgem that they will no longer be able to claim 100% allowances on deferred revenue expenditure from 1 April 2005. In recognition of these claims Ofgem, in calculating the tax allowance, has assumed that none of the costs covered by the main capital expenditure allowances shown in Appendix 3 (other than those relating to pensions as discussed below) will be eligible for 100% allowances.

8.61. The tax allowance is based on the present corporation tax rate of 30% using Ofgem's forecast of profits chargeable to corporation tax. Tax is not provided on additional revenues arising from incentive mechanisms as these revenues are in excess of the underlying costs of running the business, or for revenue relating to costs already incurred.

8.62. The assumptions used to calculate the tax allowance are based on Ofgem's review of the companies' 2002/03 corporation tax computations and forecast tax costs. Ofgem has generally used opening capital allowance balances taken from the companies' actual 2002/03 (or nearest year) tax computations as submitted to the Inland Revenue and would expect to use actual tax computations as submitted to the Inland Revenue in future, subject to consideration at the next review.

8.63. The categorisation of future capital expenditure between tax pools has been based on generic assumptions.

8.64. In previous documents, the calculation of the tax allowance has assumed that capitalised pension costs will be treated for tax purposes as a capital cost that will receive capital allowances. Since September, several DNOs have acknowledged that they can claim a revenue deduction for pension costs in the year they are paid. Therefore Ofgem has changed the treatment of pensions for

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[33] The exact Vanilla WACC used in the financial model is 5.545%

the tax allowance so that all pension costs are assumed to be allowed for tax in the year that they are paid.

8.65. Ofgem has also made some other adjustments to the tax assessments to reflect updated information provided by the DNOs on opening balances and balances that did not relate to distribution assets. However, Ofgem has not increased tax allowances to provide additional revenues for companies that did not claim capital allowances to which they were entitled (whether in respect of distribution or non-distribution assets).

8.66. Ofgem has based the tax allowance on a notional balance sheet with the gearing level assumed for the cost of capital calculation (i.e. 57.5%). However, Ofgem has previously explained that one of the reasons for moving to a post-tax approach to the cost of capital was that it allows the incentives to increase gearing to be mitigated. To achieve this, if any DNO has gearing in excess of 57.5% and interest costs higher than those in the financial model underpinning these final proposals, Ofgem intends to claw back the associated tax benefits for customers at the next review (based on the difference between actual interest and interest charges included in financial model underpinning these Final Proposals).

8.67. Table 8.6 summarises the changes to tax allowances since Initial Proposals.

Table 8.6 Average Allowances for Tax Costs

DNO	Initial Proposals £m	September update £m	November Final Proposals £m	Increase / (decrease) from September Update £m
CN - Midlands	22.7	28.8	26.0	(2.8)
CN - East Midlands	16.7	27.9	26.1	(1.8)
United Utilities	15.8	24.9	22.7	(2.2)
CE - NEDL	11.3	16.6	13.5	(3.1)
CE - YEDL	17.3	22.0	23.5	1.5
WPD - South West	14.0	18.4	16.4	(2.0)
WPD - South Wales	12.1	16.7	14.3	(2.4)
EDF - LPN	22.0	26.7	23.1	(3.6)
EDF - SPN	7.9	15.9	12.4	(3.5)
EDF - EPN	17.7	25.0	25.1	0.1
SP Distribution	30.2	38.5	38.7	0.2
SP Manweb	12.3	16.9	14.3	(2.6)
SSE - Hydro	18.0	22.4	22.2	(0.2)
SSE - Southern	38.1	44.4	39.4	(5.0)
Total	**256.0**	**345.1**	**317.7**	**(27.4)**

8.68. Ofgem's expectation is that any items of costs incurred in 2005-2010 that are remunerated after 2010 will be reflected in adjustments net of tax. This will include pension over or under funding relative to the allowance.

8.69. The September Update discussed the risks and incentives associated with tax. In practice it is difficult to structure a mechanism to calculate under and over performance for tax. This issue has been discussed with the DNOs and responses, as to whether or not such a mechanism should be introduced, have been mixed. However, a consistent view was expressed that any such scheme, if introduced, should be clear and capable of being set out in detail as a part of Final Proposals. Ofgem is mindful of the potential to over-complicate the price review with such a scheme and also notes that the proposal not to alter incentives on operating costs, as described in Chapter 7 above, reduces the potential for tax incentives to be substantially stronger than all other cost incentives. After considering these factors Ofgem has decided not to introduce a tax incentive/risk sharing scheme.

Financial indicators

8.70. In setting the price control, Ofgem needs to ensure that companies can finance their regulated activities. In addition to setting an appropriate cost of capital and other assumptions, Ofgem considers "financeability" by calculating and assessing certain financial ratios that are used by credit rating agencies and others in the financial community to assess the financial strength of a company. Ofgem's views on this and in particular the role of shareholders in providing equity finance and the other potential means of improving financial ratios were discussed in the September Update.

8.71. Ofgem has previously indicated that it intends to propose price controls that are consistent with the regulated companies being able to maintain credit ratings that are comfortably within investment grade. In order to assess whether the proposals are consistent with this approach, Ofgem has examined a range of financial indicators. This assessment has been based on a financial model with initial gearing set in line with that used in the cost of capital assessment (i.e. 57.5%) and, for the purposes of this financial model, Ofgem has assumed a dividend yield of 5 per cent.

8.72. For three indicators, conservative test values, which would be consistent with credit ratings comfortably within investment grade, were set out in Initial Proposals. These were:

- funds flow from operation (FFO) / interest not less than 3x
- retained cashflow to debt not less than 9%
- debt to RAV not higher than 65%

8.73. In discussions with Ofgem, the credit rating agencies have noted that their ratings are based on broader assessments of a company and not just on a limited set of quantitative indicators.

8.74. Following publication of the September Update, Ofgem provided the credit rating agencies with illustrative models showing a range of different scenarios. The feedback from the credit rating agencies has been valuable in Ofgem's evaluation of the forecast financial indicators.

8.75. In the light of discussions with the rating agencies, Ofgem has concluded that for standalone distribution companies (ignoring any effect of their ownership or wider group businesses), weaker test ratios than those shown above could still be consistent with ratings comfortably within investment grade.

8.76. On the basis of Ofgem's modelling, without any adjustment, all the distribution companies other than EDF-SPN have financial indicators that are at least adequate to enable them to maintain a comfortable investment grade rating. On average, gearing (on a net debt to RAV basis) remains broadly stable over the price control period.

8.77. In the case of EDF-SPN, without further adjustment, the financial indicators would deteriorate in the latter years of the control period. In large part, this is due to its combination of a low starting RAV with relatively higher projections of capital expenditure. EDF have also argued that SPN faces higher risks than other companies relative to the size of its RAV and that there are several aspects of the price review which make it particularly challenging for SPN. Ofgem does not accept these arguments, but does acknowledge that some adjustment is appropriate for SPN to reflect its specific circumstances in this price control.

8.78. Ofgem therefore proposes to make two adjustments to the price control proposals for EDF-SPN but not for any other DNO, to:

- adjust the balance between the P0 and X factors, to provide additional revenues in the latter years of the price control period when cashflow would otherwise be weakest, by setting X so that prices increase by RPI+2 in 2006/07 and thereafter, with a corresponding reduction in the P0 value to ensure that the present value of revenues continues to equal the present value of costs and other allowances; and

- provide an additional revenue allowance of £1.6m per year to provide a small cushion against downside risks and improve the projected financial ratios.

8.79. Taken together, these adjustments give rise to Final Proposals for EDF-SPN that, in Ofgem's view, taking account of discussions with the credit rating agencies, would be sufficient to allow them to maintain a credit rating comfortably within investment grade. For avoidance of doubt, these adjustments do not involve any changes to depreciation or the RAV. They reflect SPN's particular situation and would not necessarily be the most appropriate response were other companies (or SPN at a different review) faced with similar financial indicators.

8.80. For some companies, Ofgem's modelling shows strong financial ratios. In the September Update document Ofgem pointed out that this was particularly the case for the Scottish companies, which still benefit from depreciation of pre-vesting assets throughout the period to 2010, and suggested that there might be merit in deferring some depreciation into the subsequent price control period in order to lessen the adjustment required once pre-vesting assets are fully depreciated. However, following discussion with the DNOs and consideration of the responses to the September Update Paper, Ofgem has decided not to make any such adjustments.

Financial modelling

8.81. As explained in Initial Proposals, the financial model calculates price control revenue so as to set the present value of revenues equal to the present value of costs. The September Update Paper explains these issues in more detail. Ofgem's consultants LECG Ltd have audited the financial model and they have confirmed that the outputs from the model are consistent with Ofgem's assumptions.

8.82. The financial models that supported both the Initial Proposals and the September Update for each company have been shared with the companies and issues arising have been discussed. The companies have also been provided with the financial model supporting these Final Proposals. In Ofgem's view, the transparency of the price control process would have been facilitated by publication of the full, populated financial model. However, some companies have objected on grounds of the confidentiality of the data. Ofgem has therefore decided not to publish the individual financial models. Much of the data is provided in summary form in the price control calculations for the individual DNOs included in Chapter 9 and a version of the model with total industry data (summing the data inputs for all 14 licensees) will be available from Ofgem on request.

8.83. Table 8.7 below shows the main reasons for changes in the P0 values since the September Update.

Table 8.7 Effect of incremental changes in P0 from September Update

DNOs	September paper	2004/05 Revenue	Model / Data Updates	Tax	IFI	Cost of Capital	November paper Final Proposals
CN - Midlands	**(4.5%)**	1.1%	0.4%	(1.8%)	0.4%	1.5%	**(2.9%)**
CN - East Midlands	**(7.5%)**	1.2%	0.2%	(1.3%)	0.4%	1.3%	**(5.7%)**
United Utilities	**5.6%**	0.0%	2.3%	(1.7%)	0.4%	1.4%	**8.0%**
CE - NEDL	**(2.9%)**	0.0%	0.0%	(2.6%)	0.4%	1.3%	**(3.7%)**
CE - YEDL	**(12.9%)**	0.0%	2.0%	0.1%	0.4%	1.3%	**(9.2%)**
WPD-South West	**1.6%**	0.0%	(0.3%)	(1.8%)	0.4%	1.5%	**1.5%**
WPD-South Wales	**7.3%**	0.0%	(0.5%)	(2.4%)	0.4%	1.4%	**6.2%**
EDF - LPN	**(4.2%)**	0.8%	1.6%	(2.2%)	0.4%	1.2%	**(2.4%)**
EDF - SPN	**3.0%**	1.1%	4.1%	(2.9%)	0.4%	1.5%	**7.2%**
EDF - EPN	**(2.1%)**	1.0%	(0.2%)	(0.6%)	0.4%	1.4%	**(0.1%)**
SP Distribution	**10.6%**	0.0%	(0.0%)	(0.5%)	0.4%	1.4%	**11.9%**
SP Manweb	**(5.5%)**	0.0%	(0.3%)	(2.0%)	0.4%	1.5%	**(5.9%)**
SSE - Hydro	**2.7%**	0.0%	(0.0%)	(0.7%)	0.4%	1.5%	**3.9%**
SSE - Southern	**9.2%**	0.0%	0.5%	(2.3%)	0.4%	1.5%	**9.3%**
Average	**0.0%**	0.4%	0.7%	(1.6%)	0.4%	1.4%	**1.3%**

Notes:
1. The change due to cost of capital is inclusive of the tax effect of the change.
2. Tax includes the effect of all changes in P0 due to tax, except the tax effect of cost of capital.
3. The change in 2004/05 revenue is due to making the treatment of merger tax consistent in 2004/05 and 2005/06.
4. The significant model and data updates are:
- the addition of an opex roller for 2005/06 - 2007/08, UU (P0 0.4%), YEDL (P0 1.7%)and WPD S. Wales (P0 0.1%)
- additional regional allowance for LPN having a P0 effect of 0.6%
- an additional revenue for SPN having a P0 effect of 0.8%
- revision of SPN's pensions allowance which has a P0 effect of 1.5%
- an allowance for singleton DNOs, CN - Midlands (P0 0.4%), CN -East Midlands (P0 0.3%), UU (P0 1.2%) and SPN (P0 0.9%).
5. For comparability, EDF - SPN is shown on the basis of X=0. Actual P0 will be 3.1%, with RPI +2.
6. The Figures include an allowance for Innovation Funding Incentive (IFI)

Financial ring-fence

8.84. Previous documents, in particular the December 2003 document and the March 2004 policy paper, discussed the financial ring-fence. Ofgem remains of the view that there is no need for a substantial strengthening of the existing financial ring-fence arrangements. An important consideration in Ofgem's thinking has been the introduction of a Special Administration regime for energy network companies under the Energy Act 2004. However, it would not address the situation where the parent company gets into financial distress, which may result in increased pressure on the licensed entity.

8.85. Ofgem therefore considers it important to clarify how the existing financial ring-fence arrangements would be enforced. For this purpose, Ofgem is proposing a collective modification of standard condition 47 of electricity distribution licences (and, in due course, the equivalent conditions of electricity transmission and gas transporter licences), to require that, in certain circumstances once a 'trigger event' has occurred, prior consent of the Authority be obtained for any transaction of a type referred to or described in standard condition 47 (1)(b)(i)-(vii) (Transactions with affiliates and related undertakings). The structure and scope of price control licence modifications appendix contains the draft licence conditions which also contain other changes to the financial ring-fence and regulatory accounts licence conditions. These include some changes to the definitions and the inclusion of an issuer rating by Fitch Ratings Ltd or any of its subsidiaries for the purposes paragraph 2 (a) of standard condition 46.

8.86. Standard condition 47(1)(b) prohibits the licensee, without the prior written consent of the Authority, from transferring, leasing, licensing or lending any sum or sums, asset, right or benefit to any affiliate or related undertaking otherwise than by way of certain types of transaction, and subject to certain conditions, set out in sub-paragraphs (i) to (vii) inclusive. These transactions include payment of dividends and other distributions, certain transfers of money or other valuable assets on deferred payment or repayment terms, payments of principal and interest on certain loans, fair value payments for goods, services and tax losses, and acquisitions of certain investments.

8.87. Ofgem is proposing to continue to allow such transactions to be made without the need for prior written approval of the Authority unless, a trigger event has occurred and has activated a so-called 'cash lock up'. This trigger event at the relevant time, could either be that:

(a) the licensee does not hold an investment grade issuer credit rating within the meaning in standard condition 46 (Credit Rating of Licensee); or

(b) the licensee's issuer credit rating is BBB- by Standard & Poor's Ratings Group or Fitch Ratings Ltd or Baa3 by Moody's Investors Service, Inc. or such issuer credit rating as may be specified by any of these credit rating agencies from time to time as the lowest investment grade credit rating and is on:

(i) review for possible downgrade; or

(ii) CreditWatch or Rating Watch with a negative designation; or

where neither (i) nor (ii) applies:

(iii) the rating outlook of the licensee as specified by any credit rating agency referred to in sub-paragraph (b) has been changed from stable or positive to negative.

8.88. The cash lock up mechanism is activated in any of the above three circumstances. This results in the licensee having to obtain prior written approval from the Authority for any transaction as outlined in paragraph 1(b) of standard condition 47 other than the exceptions outlined in paragraph 4 of standard condition 47 which are:

(a) payment properly due for any goods, services or assets in relation to commitments entered into prior to the date on which the trigger event as described in paragraph 8.87 has occurred, and which are provided on an arm's length basis and on normal commercial terms;

(b) a transfer, lease, licence or loan of any sum or sums, asset, right or benefit on an arm's length basis, on normal commercial terms and where the value of the consideration due in respect of the transaction in question is payable wholly in cash and is paid in full when the transaction is entered into;

(c) repayment of or payment of interest on a loan not prohibited by sub-paragraph 1(a) in standard condition 47 and which was contracted prior to the date on which the trigger event as described in paragraph 8.87 has occurred provided that such payment is not made earlier than the original due date for payment in accordance with its terms; and

(d) payments for group corporation tax relief or for the surrender of Advance Corporation Tax calculated on a basis not exceeding the value of the benefit received provided the payments are not made before the date on which the amounts of tax thereby relieved would otherwise have been due.

8.89. In order to reduce the administrative burden to which the need for prior approval could give rise, the Authority would, in any particular case, consider giving a general consent for certain other transactions within individual or overall limits to be discussed and agreed with the licensee in the light of the circumstances prevailing at the relevant time.

8.90. There should be no presumption that any consent for which application might be made would be granted. Before granting any such consent, the Authority would, among other things, need to be satisfied that implementation of the relevant transaction(s) would not materially impair the licensee's ability to continue to comply in all material respects with its obligations under the relevant sectoral statutes and its licence, nor materially impair its ability to redress its financial position or restore its issuer credit rating(s) to a level comfortably above the trigger as soon as practicable, nor adversely affect its access to liquidity in the meantime.

8.91. The Authority would also have regard to the extent to which the licensee was or could be obliged to implement the relevant transaction by an enforceable agreement previously entered into consistently with its licence. Nevertheless, licensees should avoid entering into such commitments at any time when there is a reasonable likelihood that the requirement for prior approval may be triggered in the foreseeable future.

8.92. In the case of a split rating, the trigger would be activated by the lower (or lowest) of the licensed entity's ratings. It would not be necessary that all relevant rating agencies assign similar ratings or take similar rating actions to trigger the requirement for prior approval. The requirement would continue to apply until such time as all of the licensee's issuer credit ratings have been restored to a level above the trigger.

8.93. This proposal reflects a similar approach to that taken by Ofgem in the case of Aquila Networks plc when its credit ratings were downgraded to Baa3/BBB-/negative outlook at the end of 2002. The particular circumstances of Aquila Networks enabled this to be done without the need for a licence modification or enforcement order. Such circumstances do not apply to the generality of licensees. Modification of licences in the way proposed would thus put all licensees on an equal footing. By ensuring that the requirement automatically becomes operative once the trigger is breached, instant protection would be provided to both the licensed entity and consumers, whilst also providing greater clarity and improving transparency.

9. Price control calculations

9.1. This Chapter explains the way that the price controls have been set, including the key assumptions that have been adopted in order to derive price control revenue.

The components of the price control

9.2. Price controls provide a company with a level of revenue that is sufficient to finance an efficient business. This is based on an estimate of operating expenditure; capital expenditure; financing costs; corporation tax, the effect of incentive schemes and the recovery of certain costs incurred in 2000-05.

9.3. The allowed revenue figure included in the price control calculation tables excludes income from IFI. This is because IFI revenue is provided on a partial pass-through basis in addition to base revenues (i.e. it is not included in base revenues in the price control formula). However, Ofgem expects that IFI will increase prices to customers in the short-term and has therefore included this effect in the overall P0 figures presented here.

The balance between 'P0' and 'X'

9.4. In setting the price control a decision needs to be made about the balance between an immediate price decrease/increase (so called 'P0' adjustment) in the first year of the price control and the path of prices over the remaining years of the price control (X). There is no "right" answer on the appropriate balance between P0 and X but two main factors are considered in coming to a decision, namely the financial profile of companies and the longer-term trend of prices.

9.5. Having considered these issues, Ofgem has used an X factor of zero (i.e. RPI-0) for these Final Proposals with the exception of EDF-SPN. As explained in Chapter 8, the X factor for SPN has been set to give revenue changes of RPI+2 per cent from April 2006 onwards, with a correspondingly lower P0. In the summary of this document, in Table 8.1 (effect of incremental changes in P0) and in the price control calculation sheets an adjustment has been made to the

P0 of EDF-SPN to show what the P0 would have been with an X of zero, so that the P0s for all companies are shown on a comparable basis.

Price control calculations

9.6. The following tables set out how the price controls have been calculated for each DNO based on the approach outlined in each of the relevant Chapters of this document. For the avoidance of doubt, the costs associated with excluded services that are included in opex are excluded from price control revenue. The calculations of price control revenues do not take account of any incentive payments under the incentive schemes that will apply in 2005-10 for losses, quality of service, distributed generation, IFI or RPZ. The price control revenues shown here also do not include the effect of the merger adjustment that applies to those companies that have merged since May 2002.

Calculating the five year movement in the RAV

9.7. The calculation of the movement in the RAV is shown in lines 1 to 6. In each year total net capex (line 2) is added to the opening RAV (line 1) and the allowed level of depreciation (line 3) is subtracted from it to give a closing asset value (line 4). The closing value in any year (line 4) then becomes the next year's opening value (line 1). The difference between the present values of the opening RAV in 2005/06 (shown in line 5) and the closing RAV in 2009/10 (also shown in line 5) is then shown in line 6 and line 18.

Calculating allowed items

9.8. The allowed levels of costs and associated items are shown in lines 7 to 19. Line 7 shows the allowed level of opex excluding pensions. Table A5 in Appendix 3 provides an analysis of average opex over the price control period. Capital expenditure excluding pensions is shown in line 8 and is analysed in table A10 in Appendix 3. The pensions allowance is shown in line 9 and the tax allowance is shown in line 10.

9.9. The capex incentive scheme (rolling retention of capex efficiencies in 2000-05) is given by line 11, the sliding scale additional income is shown in line 12, the opex incentive and other adjustments are shown in line 13, the quality of service reward is in line 14 and costs incurred in the period 2000 to 2005 which Ofgem has agreed to remunerate through the next price control are included in line 15.

9.10. The total level of allowed items is given by line 16. The present value of these items in each year is then given by line 17. This is calculated by discounting the total allowed items figure by the vanilla WACC of 5.545%. The total of the present value of allowed items over five years and the five year movement in closing RAV is shown in line 19.

Calculating allowed revenue

9.11. In order to profile revenue, a revenue index is calculated based on companies' projections of growth in consumer numbers and units distributed, as shown in line 20. This is then discounted as for the total allowed items line, as shown in line 21.

9.12. Price control revenue in line 22 is then derived by taking the total present value of allowed items and the five year movement in closing RAV in line 19, deducting the present value of excluded services revenue for the period 2005/06 to 2009/10 (line 23), dividing the result by the sum of the discounted revenue index in line 21 and then multiplying by the revenue index in line 20. The relevant items of excluded services revenue (those for which costs remain in the operating cost excluding pensions allowance in line 7) are included in line 23.

9.13. Total revenue is shown in line 24 and is the sum of price control revenue (line 22) and excluded services revenue (line 23). The present value of line 24 is shown in line 25 and the total present value over five years is shown in line 26.

Calculating P0

9.14. Total price control revenue is allocated between P0 (line 27) and an X (line 31) of zero (with the exception of SPN). The P0 effect of IFI is shown in line 28. For SPN only, line 29 shows the effect of the reversal of its different X factor. Line 30 is the total of lines 27, 28 and 29 and shows total P0 on the basis of an X factor of zero.

Breakdown of P0

9.15. Each table also shows the main factors driving the changes in price control revenue.

9.16. Line 32 shows the effect on P0 of including charges to consumers connected to the network at the EHV level within the price control (see Chapter 3). Line 33 shows the effect on P0 of moving metering services and assets into a separate price control (see Chapter 6).

9.17. Line 34 shows the impact on P0 of changes in the opex allowance including efficiency savings already achieved by DNOs during this price control period, future efficiency targets and other opex assumptions (see Chapter 7 and Appendix 3).

9.18. Line 35 shows the impact of changes in depreciation resulting from the interaction of assumptions about capital expenditure and asset lives (see Chapter 8). Line 36 shows the impact of increasing the cost of capital from 6.5 per cent pre-tax real to 6.9 per cent pre-tax real (see Chapter 8) and changes in the size of the RAV over time.

9.19. Line 37 shows the estimated impact of changes to business rates resulting from the revised rateable valuations (see Chapter 7). Line 38 shows the impact of changes to the expected level of efficient tax liabilities (see Chapter 8).

9.20. Line 39 shows the effect on P0 of other factors – these include the effect of spreading the base price control revenue evenly over the 5 years of the price control and, for example, the effect of inclusion of expected losses incentive payments in 2004/05 in the revenue forecasts provided by the companies.

9.21. Line 40 is the total of lines 32 to 39 and shows total P0.

PRICE CONTROL CALCULATIONS FOR CN - MIDLANDS
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		964.7	1,013.2	1,057.4	1,095.1	1,126.5
2	Total capex		120.8	120.4	120.0	119.5	119.3
3	Depreciation		(72.3)	(76.2)	(82.2)	(88.2)	(94.2)
4	Closing asset value		1,013.2	1,057.4	1,095.1	1,126.5	1,151.6
5	Present value of opening / closing RAV		964.7				879.3
6	5 Year movement in closing RAV						85.4
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		72.5	70.0	68.0	66.6	66.0
8	Capital expenditure (excluding pensions)		111.5	111.1	110.7	110.2	110.0
9	Pensions allowance		16.2	16.2	16.2	16.2	16.2
10	Tax allowance		25.2	26.1	26.2	26.3	26.0
11	Capex incentive scheme		1.2	0.9	1.0	0.5	0.6
12	Sliding scale additional income		1.4	1.5	1.5	1.6	1.6
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		0.9	-	-	-	-
16	**Total allowed items**		**229.0**	**225.7**	**223.6**	**221.4**	**220.4**
17	Present value of allowed items		222.9	208.2	195.3	183.3	172.9
18	5 Year movement in closing RAV						85.4
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,068.0**
	REVENUE						
20	Revenue index		1.000	1.007	1.015	1.022	1.029
21	Discounted revenue index		0.973	0.929	0.887	0.846	0.807
22	**Price control revenue**	**246.1**	**238.0**	**239.8**	**241.6**	**243.3**	**245.0**
23	Excluded services revenue		2.4	2.4	2.4	2.4	2.4
24	Total revenue		240.4	242.2	244.0	245.7	247.4
25	Present value of total revenue		234.0	223.4	213.2	203.4	194.1
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,068.0**
27	P0 based on the above Revenue (line 22)		(3.3%)				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		**(2.9%)**				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	1.1%					
33	Exclude metering	(0.6%)					
34	Change in Opex	(8.8%)					
35	Depreciation	(1.0%)					
36	Return	2.3%					
37	Rates	(1.0%)					
38	Tax	5.3%					
39	Other	(0.3%)					
40	**Total**	**(2.9%)**					

Notes:

1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR CN - EAST MIDLANDS
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		947.9	989.2	1,030.2	1,064.8	1,093.2
2	Total capex		117.8	117.5	117.0	116.6	116.4
3	Depreciation		(76.5)	(76.5)	(82.4)	(88.2)	(94.1)
4	Closing asset value		989.2	1,030.2	1,064.8	1,093.2	1,115.6
5	Present value of opening / closing RAV		947.9				851.7
6	5 Year movement in closing RAV						96.2
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		75.2	77.7	78.2	76.9	76.2
8	Capital expenditure (excluding pensions)		110.3	109.9	109.4	109.0	108.8
9	Pensions allowance		13.0	13.1	13.1	13.1	13.1
10	Tax allowance		26.6	25.7	25.8	26.2	26.2
11	Capex incentive scheme		(0.8)	0.6	(0.6)	(0.6)	(0.2)
12	Sliding scale additional income		1.4	1.4	1.5	1.5	1.6
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		1.5	-	-	-	-
16	**Total allowed items**		**227.1**	**228.4**	**227.4**	**226.1**	**225.6**
17	Present value of allowed items		221.1	210.6	198.7	187.2	176.9
18	5 Year movement in closing RAV						96.2
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,090.7**
	REVENUE						
20	Revenue index		1.000	1.009	1.020	1.033	1.044
21	Discounted revenue index		0.973	0.931	0.891	0.855	0.819
22	**Price control revenue**	**256.2**	**240.6**	**242.8**	**245.5**	**248.5**	**251.2**
23	Excluded services revenue		3.5	3.5	3.5	3.5	3.5
24	Total revenue		244.1	246.3	249.0	252.0	254.7
25	Present value of total revenue		237.6	227.2	217.5	208.6	199.8
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,090.7**
27	P0 based on the above Revenue (line 22)		(6.1%)				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		(5.7%)				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	1.3%					
33	Exclude metering	(1.6%)					
34	Change in Opex	(2.9%)					
35	Depreciation	(2.7%)					
36	Return	1.9%					
37	Rates	0.8%					
38	Tax	5.4%					
39	Other	(7.7%)					
40	**Total**	**(5.7%)**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR UNITED UTILITIES
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	**£m**	**£m**	**£m**	**£m**	**£m**
	RAV						
1	Opening asset value		920.0	964.3	1,002.5	1,034.7	1,060.8
2	Total capex		112.7	112.3	111.8	111.4	110.9
3	Depreciation		(68.5)	(74.1)	(79.7)	(85.3)	(90.9)
4	Closing asset value		964.3	1,002.5	1,034.7	1,060.8	1,080.9
5	Present value of opening / closing RAV		920.0				825.2
6	5 Year movement in closing RAV						94.8
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		67.0	64.7	63.1	61.7	60.2
8	Capital expenditure (excluding pensions)		103.5	103.1	102.6	102.2	101.7
9	Pensions allowance		16.0	16.0	16.0	16.0	16.0
10	Tax allowance		19.4	22.0	23.1	24.5	24.5
11	Capex incentive scheme		1.8	1.0	(0.6)	(1.1)	(0.5)
12	Sliding scale additional income		1.6	1.7	1.8	1.8	1.9
13	Opex incentive / Other adjustments		1.4	1.4	1.4	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		1.5	-	-	-	-
16	**Total allowed items**		**212.3**	**209.9**	**207.5**	**205.1**	**203.8**
17	Present value of allowed items		206.6	193.6	181.3	169.8	159.9
18	5 Year movement in closing RAV						94.8
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,006.1**
	REVENUE						
20	Revenue index		1.000	1.011	1.013	1.022	1.024
21	Discounted revenue index		0.973	0.932	0.885	0.846	0.803
22	**Price control revenue**	**205.2**	**220.9**	**223.2**	**223.7**	**225.8**	**226.1**
23	Excluded services revenue		5.8	5.8	5.8	5.8	5.8
24	Total revenue		226.7	229.0	229.5	231.6	231.9
25	Present value of total revenue		220.6	211.2	200.6	191.7	181.9
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,006.1**
27	P0 based on the above Revenue (line 22)		7.6%				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		8.0%				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	1.5%					
33	Exclude metering	(1.3%)					
34	Change in Opex	(7.0%)					
35	Depreciation	7.8%					
36	Return	2.7%					
37	Rates	1.0%					
38	Tax	5.0%					
39	Other	(1.6%)					
40	**Total**	**8.0%**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR CE - NEDL
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		596.6	624.6	648.9	669.5	686.5
2	Total capex		72.3	72.3	72.3	72.2	72.2
3	Depreciation		(44.4)	(48.0)	(51.6)	(55.2)	(58.8)
4	Closing asset value		624.6	648.9	669.5	686.5	699.9
5	Present value of opening / closing RAV		596.6				534.4
6	5 Year movement in closing RAV						62.2
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		46.3	47.6	47.2	46.7	46.3
8	Capital expenditure (excluding pensions)		62.3	62.2	62.1	61.9	61.8
9	Pensions allowance		17.4	17.5	17.7	17.9	18.0
10	Tax allowance		12.7	13.1	13.5	13.9	14.3
11	Capex incentive scheme		2.4	2.0	1.7	1.1	0.6
12	Sliding scale additional income		1.1	1.2	1.2	1.2	1.3
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		1.8	-	-	-	-
16	**Total allowed items**		**144.0**	**143.6**	**143.3**	**142.8**	**142.3**
17	Present value of allowed items		140.2	132.4	125.2	118.2	111.6
18	5 Year movement in closing RAV						62.2
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**689.9**
	REVENUE						
20	Revenue index		1.000	1.014	1.028	1.042	1.056
21	Discounted revenue index		0.973	0.935	0.898	0.863	0.828
22	**Price control revenue**	**158.8**	**152.2**	**154.3**	**156.5**	**158.6**	**160.7**
23	Excluded services revenue		1.2	1.2	1.2	1.2	1.2
24	Total revenue		153.4	155.5	157.7	159.8	161.9
25	Present value of total revenue		149.3	143.5	137.8	132.3	127.0
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**689.9**
27	P0 based on the above Revenue (line 22)		(4.1%)				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		(3.7%)				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	5.5%					
33	Exclude metering	(1.4%)					
34	Change in Opex	(10.7%)					
35	Depreciation	5.0%					
36	Return	1.5%					
37	Rates	1.1%					
38	Tax	3.4%					
39	Other	(8.1%)					
40	**Total**	**(3.7%)**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR CE - YEDL
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		804.6	826.2	852.9	875.2	892.9
2	Total capex		88.8	88.7	88.7	88.7	88.5
3	Depreciation		(67.2)	(62.0)	(66.5)	(70.9)	(75.3)
4	Closing asset value		826.2	852.9	875.2	892.9	906.1
5	Present value of opening / closing RAV		804.6				691.8
6	5 Year movement in closing RAV						112.8
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		62.2	60.6	59.0	58.4	57.9
8	Capital expenditure (excluding pensions)		83.0	82.8	82.6	82.5	82.3
9	Pensions allowance		10.1	10.3	10.5	10.7	10.8
10	Tax allowance		20.8	22.2	23.4	25.6	25.6
11	Capex incentive scheme		1.6	0.2	(1.9)	(1.9)	(1.3)
12	Sliding scale additional income		1.5	1.5	1.6	1.6	1.6
13	Opex incentive / Other adjustments		6.4	6.4	6.4	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		1.0	-	-	-	-
16	**Total allowed items**		**186.5**	**184.1**	**181.6**	**176.8**	**176.9**
17	Present value of allowed items		181.5	169.7	158.7	146.4	138.8
18	5 Year movement in closing RAV						112.8
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**908.0**
	REVENUE						
20	Revenue index		1.000	1.010	1.020	1.030	1.041
21	Discounted revenue index		0.973	0.931	0.891	0.853	0.816
22	**Price control revenue**	**221.8**	**200.6**	**202.6**	**204.6**	**206.7**	**208.7**
23	Excluded services revenue		2.8	2.8	2.8	2.8	2.8
24	Total revenue		203.4	205.4	207.4	209.5	211.5
25	Present value of total revenue		198.0	189.4	181.2	173.4	165.9
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**908.0**
27	P0 based on the above Revenue (line 22)		(9.6%)				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		(9.2%)				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	2.3%					
33	Exclude metering	(1.9%)					
34	Change in Opex	(6.2%)					
35	Depreciation	(6.0%)					
36	Return	0.8%					
37	Rates	(1.0%)					
38	Tax	5.7%					
39	Other	(2.8%)					
40	**Total**	**(9.2%)**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR WPD - SOUTH WEST
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		695.6	717.4	734.0	747.0	756.3
2	Total capex		72.1	72.1	72.1	72.1	72.1
3	Depreciation		(50.3)	(55.5)	(59.1)	(62.7)	(66.3)
4	Closing asset value		717.4	734.0	747.0	756.3	762.1
5	Present value of opening / closing RAV		695.6				581.8
6	5 Year movement in closing RAV						113.7
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		53.2	55.2	56.0	55.5	55.1
8	Capital expenditure (excluding pensions)		63.8	63.7	63.5	63.4	63.3
9	Pensions allowance		14.4	14.6	14.8	15.0	15.2
10	Tax allowance		15.2	15.7	16.4	17.1	17.9
11	Capex incentive scheme		4.5	4.1	2.8	1.8	0.9
12	Sliding scale additional income		1.4	1.5	1.5	1.5	1.5
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		1.7	1.7	1.7	1.7	1.7
15	DPCR3 costs		1.6	-	-	-	-
16	**Total allowed items**		**155.8**	**156.5**	**156.7**	**156.1**	**155.5**
17	Present value of allowed items		151.7	144.3	136.9	129.2	122.0
18	5 Year movement in closing RAV						113.7
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**797.9**
	REVENUE						
20	Revenue index		1.000	1.013	1.027	1.038	1.051
21	Discounted revenue index		0.973	0.934	0.897	0.860	0.825
22	**Price control revenue**	**173.1**	**174.9**	**177.1**	**179.6**	**181.6**	**183.9**
23	Excluded services revenue		2.9	2.9	2.9	2.9	2.9
24	Total revenue		177.8	180.0	182.5	184.5	186.8
25	Present value of total revenue		173.1	166.0	159.5	152.8	146.5
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**797.9**
27	P0 based on the above Revenue (line 22)		1.1%				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		1.5%				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	1.5%					
33	Exclude metering	(2.2%)					
34	Change in Opex	(3.8%)					
35	Depreciation	(0.9%)					
36	Return	(0.4%)					
37	Rates	1.1%					
38	Tax	3.8%					
39	Other	2.3%					
40	**Total**	**1.5%**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR WPD - SOUTH WALES
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		573.6	577.8	579.3	578.4	575.0
2	Total capex		49.9	49.7	49.7	49.7	49.7
3	Depreciation		(45.7)	(48.2)	(50.6)	(53.1)	(55.6)
4	Closing asset value		577.8	579.3	578.4	575.0	569.1
5	Present value of opening / closing RAV		573.6				434.5
6	5 Year movement in closing RAV						139.0
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		43.0	44.5	45.1	44.7	44.3
8	Capital expenditure (excluding pensions)		44.1	44.0	43.8	43.7	43.6
9	Pensions allowance		10.0	9.9	10.2	10.4	10.5
10	Tax allowance		12.5	13.5	14.3	15.1	15.9
11	Capex incentive scheme		(1.7)	(1.1)	(0.9)	(0.3)	(0.1)
12	Sliding scale additional income		1.2	1.2	1.2	1.2	1.1
13	Opex incentive / Other adjustments		0.3	0.3	0.3	-	-
14	Quality reward		1.3	1.3	1.3	1.3	1.3
15	DPCR3 costs		0.9	-	-	-	-
16	**Total allowed items**		**111.6**	**113.5**	**115.4**	**116.1**	**116.8**
17	Present value of allowed items		108.6	104.7	100.8	96.2	91.6
18	5 Year movement in closing RAV						139.0
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**640.9**
	REVENUE						
20	Revenue index		1.000	1.013	1.026	1.037	1.050
21	Discounted revenue index		0.973	0.934	0.897	0.859	0.824
22	**Price control revenue**	**134.8**	**142.7**	**144.5**	**146.4**	**148.0**	**149.8**
23	Excluded services revenue		0.2	0.2	0.2	0.2	0.2
24	Total revenue		142.9	144.7	146.6	148.2	150.0
25	Present value of total revenue		139.1	133.4	128.1	122.7	117.7
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**640.9**
27	P0 based on the above Revenue (line 22)		5.8%				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		6.2%				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	6.5%					
33	Exclude metering	(2.1%)					
34	Change in Opex	(3.4%)					
35	Depreciation	6.1%					
36	Return	0.5%					
37	Rates	1.0%					
38	Tax	5.1%					
39	Other	(7.4%)					
40	**Total**	**6.2%**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR EDF - LPN
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		909.2	952.8	992.0	1,025.4	1,053.3
2	Total capex		111.7	111.6	111.4	111.4	111.3
3	Depreciation		(68.1)	(72.4)	(78.0)	(83.6)	(89.2)
4	Closing asset value		952.8	992.0	1,025.4	1,053.3	1,075.4
5	Present value of opening / closing RAV		909.2				821.1
6	5 Year movement in closing RAV						88.2
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		60.1	62.6	64.1	63.5	62.9
8	Capital expenditure (excluding pensions)		99.2	99.0	98.8	98.6	98.5
9	Pensions allowance		21.7	21.8	21.9	22.1	22.2
10	Tax allowance		20.7	22.1	23.1	24.2	25.3
11	Capex incentive scheme		8.0	7.4	3.8	1.7	0.1
12	Sliding scale additional income		(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		4.6	-	-	-	-
16	**Total allowed items**		**214.1**	**212.7**	**211.6**	**210.0**	**208.7**
17	Present value of allowed items		208.4	196.1	184.9	173.8	163.7
18	5 Year movement in closing RAV						88.2
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,015.1**
	REVENUE						
20	Revenue index		1.000	1.015	1.031	1.047	1.063
21	Discounted revenue index		0.973	0.936	0.901	0.866	0.834
22	**Price control revenue**	**228.3**	**221.9**	**225.3**	**228.8**	**232.3**	**235.9**
23	Excluded services revenue		3.2	3.2	3.2	3.2	3.2
24	Total revenue		225.1	228.5	232.0	235.5	239.1
25	Present value of total revenue		219.1	210.8	202.7	194.9	187.5
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,015.1**
27	P0 based on the above Revenue (line 22)		(2.8%)				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		(2.4%)				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	1.6%					
33	Exclude metering	0.4%					
34	Change in Opex	(5.3%)					
35	Depreciation	(2.0%)					
36	Return	0.0%					
37	Rates	1.1%					
38	Tax	4.3%					
39	Other	(2.6%)					
40	**Total**	**(2.4%)**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR EDF - SPN
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		641.4	713.4	778.6	837.1	889.6
2	Total capex		118.6	117.8	117.0	116.9	116.9
3	Depreciation		(46.7)	(52.6)	(58.5)	(64.4)	(70.2)
4	Closing asset value		713.4	778.6	837.1	889.6	936.3
5	Present value of opening / closing RAV		641.4				714.9
6	5 Year movement in closing RAV						(73.4)
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		58.8	55.3	51.9	49.5	45.1
8	Capital expenditure (excluding pensions)		106.8	106.0	105.1	105.0	104.8
9	Pensions allowance		20.4	20.5	20.6	20.7	20.9
10	Tax allowance		10.2	11.7	12.6	13.3	14.4
11	Capex incentive scheme		(4.3)	(4.8)	(4.1)	(3.8)	(2.7)
12	Sliding scale additional income		(0.1)	(0.2)	(0.2)	(0.2)	(0.2)
13	Opex incentive / Other adjustments		1.6	1.6	1.6	1.6	1.6
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		0.8	-	-	-	-
16	**Total allowed items**		**194.1**	**190.1**	**187.6**	**186.0**	**183.9**
17	Present value of allowed items		189.0	175.3	163.9	154.0	144.2
18	5 Year movement in closing RAV						(73.4)
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**753.0**
	REVENUE						
20	Revenue index		1.000	1.029	1.059	1.090	1.122
21	Discounted revenue index		0.973	0.949	0.926	0.903	0.880
22	**Price control revenue**	**156.8**	**161.1**	**165.8**	**170.7**	**175.6**	**180.8**
23	Excluded services revenue		1.6	1.6	1.6	1.6	1.6
24	Total revenue		162.7	167.4	172.3	177.2	182.4
25	Present value of total revenue		158.4	154.4	150.5	146.7	143.0
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**753.0**
27	P0 based on the above Revenue (line 22)		2.7%				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29	Reverse of x of +2 for SPN		4.1%				
30	**Total P0 for comparison purposes**		7.2%				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	4.6%					
33	Exclude metering	(4.0%)					
34	Change in Opex	(6.3%)					
35	Depreciation	10.9%					
36	Return	7.7%					
37	Rates	(0.7%)					
38	Tax	2.8%					
39	Other	(7.7%)					
40	**Total**	**7.2%**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.
6. In the revenue calculations an X of +2 is used for SPN. For comparability purposes the P0 is also shown above as if X was zero.

PRICE CONTROL CALCULATIONS FOR EDF - EPN
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		1,138.4	1,218.3	1,290.1	1,353.6	1,409.0
2	Total capex		161.0	160.8	160.7	160.5	160.5
3	Depreciation		(81.0)	(89.1)	(97.1)	(105.2)	(113.2)
4	Closing asset value		1,218.3	1,290.1	1,353.6	1,409.0	1,456.3
5	Present value of opening / closing RAV		1,138.4				1,111.9
6	5 Year movement in closing RAV						26.5
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		90.2	90.8	89.9	89.1	88.3
8	Capital expenditure (excluding pensions)		154.0	153.7	153.5	153.2	153.0
9	Pensions allowance		12.1	12.3	12.5	12.7	12.9
10	Tax allowance		22.0	24.0	25.6	26.9	27.3
11	Capex incentive scheme		12.6	9.4	5.3	1.3	(0.5)
12	Sliding scale additional income		(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		1.6	-	-	-	-
16	**Total allowed items**		**292.2**	**289.9**	**286.5**	**282.9**	**280.6**
17	Present value of allowed items		284.4	267.4	250.3	234.2	220.1
18	5 Year movement in closing RAV						26.5
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,283.0**
	REVENUE						
20	Revenue index		1.000	1.011	1.021	1.031	1.042
21	Discounted revenue index		0.973	0.932	0.892	0.854	0.817
22	**Price control revenue**	**286.6**	**285.3**	**288.3**	**291.2**	**294.2**	**297.1**
23	Excluded services revenue		1.9	1.9	1.9	1.9	1.9
24	Total revenue		287.2	290.2	293.1	296.1	299.0
25	Present value of total revenue		279.5	267.7	256.1	245.1	234.6
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,283.0**
27	P0 based on the above Revenue (line 22)		(0.5%)				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		(0.1%)				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	2.2%					
33	Exclude metering	(2.8%)					
34	Change in Opex	(0.2%)					
35	Depreciation	(1.2%)					
36	Return	0.9%					
37	Rates	1.1%					
38	Tax	2.9%					
39	Other	(2.8%)					
40	**Total**	**(0.1%)**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR SP DISTRIBUTION
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		1,233.4	1,210.2	1,184.5	1,156.3	1,125.8
2	Total capex		85.9	85.7	85.6	85.4	85.2
3	Depreciation		(109.2)	(111.4)	(113.7)	(115.9)	(118.2)
4	Closing asset value		1,210.2	1,184.5	1,156.3	1,125.8	1,092.8
5	Present value of opening / closing RAV		1,233.4				834.4
6	5 Year movement in closing RAV						399.0
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		73.0	77.4	76.8	76.2	75.7
8	Capital expenditure (excluding pensions)		83.1	82.9	82.8	82.6	82.4
9	Pensions allowance		4.8	4.8	4.8	4.8	4.8
10	Tax allowance		35.2	36.6	38.6	40.5	42.5
11	Capex incentive scheme		(1.7)	(0.9)	0.3	1.1	1.1
12	Sliding scale additional income		0.7	0.7	0.7	0.7	0.6
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		1.5	-	-	-	-
16	**Total allowed items**		**196.6**	**201.5**	**204.0**	**205.9**	**207.1**
17	Present value of allowed items		191.4	185.8	178.2	170.4	162.5
18	5 Year movement in closing RAV						399.0
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,287.4**
	REVENUE						
20	Revenue index		1.000	1.008	1.015	1.023	1.031
21	Discounted revenue index		0.973	0.929	0.887	0.847	0.809
22	**Price control revenue**	**259.8**	**289.6**	**291.8**	**294.0**	**296.3**	**298.6**
23	Excluded services revenue		-	-	-	-	-
24	Total revenue		289.6	291.8	294.0	296.3	298.6
25	Present value of total revenue		281.9	269.1	256.9	245.3	234.2
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,287.4**
27	P0 based on the above Revenue (line 22)		11.5%				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		11.9%				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	0.3%					
33	Exclude metering	(2.2%)					
34	Change in Opex	(1.3%)					
35	Depreciation	2.4%					
36	Return	(1.5%)					
37	Rates	4.7%					
38	Tax	8.7%					
39	Other	0.7%					
40	**Total**	**11.9%**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR SP MANWEB
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		735.4	782.0	821.9	856.7	886.5
2	Total capex		98.4	98.2	98.1	97.9	97.8
3	Depreciation		(51.8)	(58.3)	(63.2)	(68.1)	(73.0)
4	Closing asset value		782.0	821.9	856.7	886.5	911.2
5	Present value of opening / closing RAV		735.4				695.7
6	5 Year movement in closing RAV						39.7
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		51.3	50.1	48.9	47.3	46.8
8	Capital expenditure (excluding pensions)		89.3	89.1	89.0	88.8	88.7
9	Pensions allowance		15.7	15.7	15.7	15.7	15.7
10	Tax allowance		13.6	14.3	14.6	14.6	14.1
11	Capex incentive scheme		0.0	(1.5)	(2.5)	(2.1)	(1.1)
12	Sliding scale additional income		0.4	0.5	0.5	0.5	0.5
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		0.9	-	-	-	-
16	**Total allowed items**		**171.2**	**168.1**	**166.1**	**164.8**	**164.7**
17	Present value of allowed items		166.6	155.0	145.2	136.4	129.2
18	5 Year movement in closing RAV						39.7
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**772.1**
	REVENUE						
20	Revenue index		1.000	1.008	1.017	1.026	1.035
21	Discounted revenue index		0.973	0.929	0.888	0.849	0.812
22	**Price control revenue**	**183.1**	**171.6**	**172.9**	**174.4**	**176.0**	**177.5**
23	Excluded services revenue		1.9	1.9	1.9	1.9	1.9
24	Total revenue		173.5	174.8	176.3	177.9	179.4
25	Present value of total revenue		168.8	161.2	154.1	147.3	140.7
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**772.1**
27	P0 based on the above Revenue (line 22)		(6.3%)				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		(5.9%)				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	4.6%					
33	Exclude metering	(1.1%)					
34	Change in Opex	(1.9%)					
35	Depreciation	2.0%					
36	Return	3.6%					
37	Rates	(1.2%)					
38	Tax	2.6%					
39	Other	(14.5%)					
40	**Total**	**(5.9%)**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR SSE - HYDRO
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		727.9	727.0	724.6	720.6	715.3
2	Total capex		49.7	49.6	49.4	49.3	49.1
3	Depreciation		(50.7)	(52.0)	(53.3)	(54.6)	(55.9)
4	Closing asset value		727.0	724.6	720.6	715.3	708.5
5	Present value of opening / closing RAV		727.9				540.9
6	5 Year movement in closing RAV						187.0
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		47.1	47.9	49.4	50.5	50.2
8	Capital expenditure (excluding pensions)		47.4	47.3	47.2	47.1	46.9
9	Pensions allowance		3.9	3.9	3.9	3.9	3.9
10	Tax allowance		20.5	21.5	22.1	22.9	24.1
11	Capex incentive scheme		6.4	5.6	4.1	2.3	0.8
12	Sliding scale additional income		1.3	1.3	1.3	1.3	1.3
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		0.9	-	-	-	-
16	**Total allowed items**		**127.6**	**127.5**	**128.0**	**128.0**	**127.2**
17	Present value of allowed items		124.2	117.5	111.9	106.0	99.8
18	5 Year movement in closing RAV						187.0
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**746.4**
	REVENUE						
20	Revenue index		1.000	1.010	1.020	1.030	1.040
21	Discounted revenue index		0.973	0.931	0.891	0.853	0.816
22	**Price control revenue**	**161.1**	**166.7**	**168.3**	**170.0**	**171.7**	**173.4**
23	Excluded services revenue		0.5	0.5	0.5	0.5	0.5
24	Total revenue		167.2	168.8	170.5	172.2	173.9
25	Present value of total revenue		162.7	155.7	149.0	142.6	136.4
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**746.4**
27	P0 based on the above Revenue (line 22)		3.5%				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		3.9%				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	1.1%					
33	Exclude metering	(2.3%)					
34	Change in Opex	(3.6%)					
35	Depreciation	1.2%					
36	Return	(2.5%)					
37	Rates	1.3%					
38	Tax	7.2%					
39	Other	1.4%					
40	**Total**	**3.9%**					

Notes: 1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

PRICE CONTROL CALCULATIONS FOR SSE SOUTHERN
2002/03 Prices

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		1,349.9	1,393.4	1,426.9	1,453.0	1,471.9
2	Total capex		142.3	142.0	141.8	141.7	141.5
3	Depreciation		(98.8)	(108.6)	(115.7)	(122.8)	(129.9)
4	Closing asset value		1,393.4	1,426.9	1,453.0	1,471.9	1,483.5
5	Present value of opening / closing RAV		1,349.9				1,132.7
6	5 Year movement in closing RAV						217.3
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		85.8	90.3	92.1	91.4	90.7
8	Capital expenditure (excluding pensions)		124.9	124.6	124.4	124.2	124.0
9	Pensions allowance		30.2	30.2	30.2	30.3	30.3
10	Tax allowance		38.7	38.3	38.7	40.1	41.1
11	Capex incentive scheme		8.4	7.8	5.2	1.9	0.1
12	Sliding scale additional income		2.5	2.6	2.6	2.7	2.7
13	Opex incentive / Other adjustments		-	-	-	-	-
14	Quality reward		-	-	-	-	-
15	DPCR3 costs		1.9	-	-	-	-
16	**Total allowed items**		**292.3**	**293.8**	**293.3**	**290.6**	**289.0**
17	Present value of allowed items		284.6	271.0	256.3	240.5	226.7
18	5 Year movement in closing RAV						217.3
19	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,496.3**
	REVENUE						
20	Revenue index		1.000	1.012	1.023	1.035	1.048
21	Discounted revenue index		0.973	0.933	0.894	0.857	0.822
22	**Price control revenue**	**305.0**	**332.2**	**336.1**	**340.0**	**343.9**	**348.0**
23	Excluded services revenue		1.9	1.9	1.9	1.9	1.9
24	Total revenue		334.1	338.0	341.9	345.8	349.9
25	Present value of total revenue		325.2	311.7	298.7	286.3	274.4
26	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,496.3**
27	P0 based on the above Revenue (line 22)		8.9%				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29							
30	**Total P0 for comparison purposes**		9.3%				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	3.0%					
33	Exclude metering	(1.0%)					
34	Change in Opex	2.0%					
35	Depreciation	(1.5%)					
36	Return	(0.5%)					
37	Rates	0.6%					
38	Tax	6.6%					
39	Other	0.1%					
40	**Total**	**9.3%**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs (excluding pensions) exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue shown above excludes NTR, metering, and EHV on pre March 2005 assets.
4. These revenue lines are before the application of the merger term.
5. Price control revenue included in the table excludes income from IFI. But a P0 is shown above for comparison purposes including the effect on P0 of IFI.

Appendix 1 RAV Roll Forward and Incentive mechanisms

Introduction

A1.1 One of the main objectives of this price review has been to provide appropriate incentives on the distribution companies, including in relation to investment, efficiency and performance. In some cases, the incentive mechanisms and bases for remuneration of investment that are set out in these Final Proposals depend on the way in which costs incurred and performance attained in the period 2005-2010 are treated in future price reviews. The incentives noted above depend, to a significant extent, on distribution companies and their investors having confidence in how these arrangements will be applied.

A1.2 In conducting price reviews, Ofgem has discretion over the ways in which price limits are set and needs to keep under review the regulatory framework in the light of all relevant developments. There can be no assurance that future reviews will be conducted in the same manner as this one. In particular, nothing in this appendix is intended to provide any guidance about how costs arising after 1 April 2010 will be treated in future reviews.

A1.3 In the light of these considerations, this appendix sets out key assumptions and principles underlying this review and explains how Ofgem expects to use these assumptions and principles as the basis for the calculation of particular values relating to 2005-10 costs and performance at the next price control review and beyond.

A1.4 Ofgem recognises the importance of predictability in regulation and does not intend to alter the treatment of costs and incentives in relation to the period 2005-10 from that set out here unless this formulation is shown to contain manifest errors or to be inconsistent with its statutory duties, taking due account of the disadvantages of changing approach. It is also possible that unforeseen new issues will arise that are not provided for in the methods set out in this appendix, in which case Ofgem will consult on the appropriate response.

A1.5 Should any licensee reject these Final Proposals, the calculations set out here may no longer apply, depending on the outcome of the Competition Commission reference.

RAV calculation 2005-10

A1.6 The regulatory asset value (RAV) is a key building block of the price control review. It can be seen as a measure of the value of the regulated business, based on past investment, on which the companies earn a return and receive depreciation.

A1.7 In developing these proposals, it has been necessary for Ofgem to decide which categories and proportions of costs should be included in the RAV of each licensee (treated as capital expenditure), and therefore remunerated over a period of time that exceeds the expected duration of these price controls, and which should not be included in the RAV.

A1.8 In order to roll forward the RAV from April 2005 to March 2010, expenditure that the DNOs incur in this period should be treated in the same way as in developing the proposals – that is, the same categories of costs added to the RAV.

A1.9 In order to perform this calculation, it is necessary to define four categories of costs:

- ♦ net non-fault operational capex;
- ♦ opex plus fault costs;
- ♦ pension costs; and
- ♦ other costs.

A1.10 These categories are intended to be mutually exclusive. They do not include interest or tax costs (except for business rates). They are all intended to refer to costs incurred by the licensee or a related party of the licensee, not to recharges between the licensee and a related party.

A1.11 Ofgem reserves the option to disallow costs from any of these categories if they do not relate to the distribution business or are demonstrably inefficient or wasteful.

A1.12 Net non-fault operational capex is defined as:

- ♦ non-fault operational capital expenditure (including, without limitation, such expenditure in relation to quality of service improvements, loss reductions, network resilience, improving service to worst served customers, health and safety, environmental issues and tree-cutting costs as part of a new construction programme or a diversion of an existing line); and
- ♦ 38 per cent of "indirect" costs (defined below);

less

- ♦ customer contributions;
- ♦ cash proceeds of sale (or market value of intra-group transfer) of operational capex disposals;
- ♦ costs logged up by agreement between the DNO concerned and Ofgem in relation to undergrounding in national parks or areas of outstanding natural beauty as specified in Chapter 4;

but excluding:

- ♦ all pension costs, all metering expenditure, all depreciation, related party margins unless specified below, operational capex falling within the distributed generation and RPZ incentive schemes (except as an agreed transfer from DG mechanism), costs in relation to pass-through items (including business rates, Ofgem licence fees, Shetland balancing costs, NTR costs, and exit charges), fines and penalties incurred by the DNO, compensation payments made in relation to standards of performance, lane rentals and ESQCR costs (to the extent that they are allowed for under the uncertainty adjustment arrangements in licence condition A3), costs falling within IFI, bad debt costs and receipts, de minimis costs, and other costs of sale (as included in table A7 of the September Update for example);

and reversing:

- any provisions and accruals to ensure costs are on a cash basis (subject to not creating boundary problems between different price control periods).

A1.13 Opex plus faults costs is defined as:

- operating expenditure, including without limitation tree-cutting costs (except as included in non-fault operational capex), insurance costs, insurance claim receipts (as negative), all storm related costs (inspection and storm damage repair);
- total fault costs (both costs incurred as operating expenditure and capital expenditure);
- non-operational capital expenditure; and
- 62% of "indirect" costs as defined below;

less:

- cash proceeds of sale (or value of intra-group transfer) of non-operational assets;
- the difference between actual and projected excluded services revenue (included on line 23 of the price control calculation sheets in this document) for categories of excluded services where the associated costs have not been excluded above.

excluding:

- costs in relation to pass-through items (including business rates, Ofgem licence fees, Shetland balancing costs, NTR costs, and exit charges), all pension costs, all metering costs, all depreciation, profit margins from related parties (except as defined below), distributed generation costs, fines and penalties, compensation payments made in relation to standards of performance and ex gratia payments, lane rentals and ESQCR costs (to the extent that they are allowed for under the uncertainty adjustment arrangements in licence condition A3), costs falling within IFI, bad debt costs and receipts, de minimis costs, and other costs of sale (as included in table A7 of the September Update for example); and

reversing

- the impact of provisions and accruals to ensure costs are on a cash basis.

A1.14 Pension costs are defined below.

A1.15 Other costs include all items excluded from the above definitions.

A1.16 Costs are only included to the extent they represent the cost of services required by the distribution business – i.e. if not provided by the group, the licensee would need to procure the services separately. Ofgem will expect the services and associated costs to be itemised and justified.

A1.17 For both opex and capex, any costs restated will be applied in the year in which the cost was incurred rather than the year of the restatement.

A1.18 Indirect costs are all costs that are not defined as direct labour, direct materials and direct contractors (external) below:[34]

- Direct labour is defined as that part of the DNO's own workforce and that of a material related party service provider that can clearly identify which system assets and/or operational premises their effort is being expended upon, evidenced by time sheets / time writing that records the amount of time spent. Direct labour excludes labour where managerial assessment or some other form of estimation is used to apportion costs to an activity. For the avoidance of doubt and to ensure consistency and comparability across DNOs, the costs associated with direct labour

[34] These definitions are entirely consistent with those sent to the DNOs on 30 March 2004 to complete the normalisation schedules.

should only be in relation to those field staff that are actually physically performing work on the network. Accordingly direct labour excludes the costs associated with depot staff, technical engineers, administration and support staff, network planners and designers etc;

- Direct materials are defined as materials drawn from supplies for specific system assets or operational premises and is supported by stores issue notes and all materials delivered directly to site; and

- Direct contractors (external) are defined as the charges invoiced by contractors (external) for work on specific system assets and/or operational premises and can include elements of labour, materials etc.

A1.19 Related party profit margins will be excluded from the definitions above unless the related party concerned earns at least 75 per cent of its turnover from sources other than related parties and charges to the licensed entity are consistent with charges to external customers. For this purpose, an entity will be considered to be a related party if it is in the same group as the DNO (be it a holding company, affiliate, subsidiary, associate, joint venture) or if that entity and the DNO have any other form of common ownership.

A1.20 The categories of costs to be included in the RAV are:

- 100 per cent of net non-fault operational capex;

- 23.5 per cent of opex plus fault costs;

- 57.7 per cent of pension costs; and

- no part of other costs.

Capital expenditure rolling incentive

A1.21 These Final Proposals provide for a rolling incentive mechanism to apply to capital expenditure (RAV additions excluding pension costs). This provides a consistent incentive for efficiency in relation to capital expenditure throughout the price control period. The starting point for this incentive mechanism is the rolling incentive applied to capital expenditure incurred in the period 2000-2005.

A1.22 As explained in Chapter 7, during the course of this review Ofgem has developed a sliding scale mechanism to accommodate the wide range of approaches between DNOs in relation to capital expenditure projections. This mechanism requires a slight modification to the incentive scheme presently in operation to accommodate the differential incentive rates that the sliding scale mechanism allows. A worked example is given in Table A1.1 below.

A1.23 The incentive mechanism applies to RAV additions whether above or below the level of the allowance. As with other incentive mechanisms in these Final Proposals, the resultant revenues for the period after 2010 are intended to be on a pre-tax basis (i.e. it is not intended that they give rise to further revenues in respect of the tax charge on the revenues). The asset lives used in each year will be as specified in Chapter 8.

A1.24 The worked example in Table A1.1 below shows that using a pre-tax cost of capital of 6.9 per cent and an asset life of 20 years, an unmodified five year retention would imply that the DNO would keep (bear) 47 per cent of the present value of a capex under- (over-) spend. If the sliding scale mechanism requires that the incentive rate is, say, 30 per cent, then it is necessary to adjust revenues downwards (upwards) by 17 per cent, to bring the net retention share back to 30 per cent. This is shown towards the bottom of Table A1.1.

A1.25 All RAV additions (excluding pension costs) in the period 2005-10 will be subject to the rolling capex incentive mechanism unless otherwise agreed by Ofgem in exceptional circumstances.

RAV calculation 2004/05

A1.26 These Final Proposals have used estimates of 2004/05 capex provided by the companies in the summer of 2004, on the understanding that these were best estimates at the time.

A1.27 Ofgem intends that the RAV values for 31 March 2004 published in this document should not be altered, unless it becomes evident that the information provided by the licensee concerned was inaccurate.

A1.28 The RAV will need to be updated from 31 March 2004 to the start of the new price control period (1 April 2005). This calculation should be done on the same basis as the RAV calculations for 2003/04, with the adjustments described in the September Update and set out in Appendix 3 (table A11), and with the value also set out in Appendix 3 (table A11) representing the depreciated replacement costs of meters removed from the RAV on 31 March 2005. For the avoidance of doubt, this means that the RAV will be rolled forward from 31 March 2004 to 1 April 2005 on a different basis from that which will apply from 1 April 2005 to 31 March 2010.

A1.29 In the event that actual 2004/05 RAV additions turn out to be materially different to the estimate used, Ofgem would not expect to alter revenue in the period 2005-10 but if the difference is not due to genuine efficiencies that could not reasonably have been foreseen at the time the forecast was provided, Ofgem may decide to claw back the benefits of any under-spend in 2004/05 relative to the estimate used in these proposals at the next review.

Operating cost incentives

A1.30 In chapter 7 Ofgem explains that in earlier documents Ofgem was proposing to treat all costs on the same basis for the purpose of determining the incentive payment companies receive for achieving efficiency savings after April 2005, i.e. that incentives for all categories of efficiency savings would be equalised (at the level applicable to capex savings). In view of the representations made by respondents, Ofgem will continue with the “traditional” differential incentives applied to opex and capex.

A1.31 Ofgem’s decision is conditional upon the DNOs providing adequate support for the cost reporting project. Therefore, if by the time of the next review Ofgem is not fully satisfied that a robust scheme for categorisation of costs is in place and being implemented by all DNOs, Ofgem will adjust its proposals for any DNO that has not adequately supported the cost reporting project. This adjustment will have the effect of ensuring that any benefit that the DNO has received, over and above what would have been achieved had the incentives for operating and capital expenditure been equalised, will be clawed back.

A1.32 The use of the "traditional incentives" means that Ofgem does not intend, except as expressly provided in paragraph A1.31, to claw back any out-performance of opex (meaning the 76.5 per cent of opex plus fault costs that does not enter the RAV) that is achieved in the period 2005 – 2010 at the next review.

Operating cost rolling incentive

A1.33 Ofgem remains of the view that rolling retention mechanisms are, in principle, an appropriate way to address the perverse effects of periodicity of incentives. However, given the difficulties experienced historically in defining operating costs on a comparable basis to the price control allowances that have been established, Ofgem does not propose to commit to a rolling 5 year mechanism for operating costs with effect from 1 April 2005. This issue may be considered further as the cost reporting project proceeds.

A1.34 For the avoidance of doubt, no rolling incentives adjustment will apply in respect of 2004/05 operating cost performance (as any efficiency gains in 2004/05 will already be retained until at least 2010).

Losses rolling incentive

A1.35 Ofgem's proposals on the losses incentive are that:

- ♦ reported losses should simply reflect the difference between the estimated volume of electricity entering and exiting the system;
- ♦ the losses target will be fixed for the five years of the price control;
- ♦ the losses incentive rate will be £48/MWh (in 2004/05 prices) for the duration of the next price control period;
- ♦ an explicit adjustment to the level of reported losses may be made to reflect the impact of distributed generation with a loss adjustment factor (LAF) below 0.997;

- expenditure on low-losses equipment will be treated as any other capex, i.e. it will be eligible for inclusion in the RAV and subject to the rolling capex incentive; and

- DNOs keep the benefit and penalties of performance against the losses target for five years through the application of a rolling retention mechanism.

A1.36 For the period 2005 to 2010, the way the losses incentive impacts upon revenues is relatively straightforward and is set out in the draft of special condition C1 in the appendix of draft licence modifications. However, the rolling incentive mechanism will give rise to adjustments to revenues beyond 2010 which are not specified in the licence condition.

A1.37 Ofgem set out a proposal for how the rolling losses incentive would work in the June Initial Proposals paper. Reviewing this table in the light of subsequent work and discussions on other incentive mechanisms, Ofgem has concluded that it does not appear to fully achieve the purpose of the incentive, which is to allow retention of the benefits of incremental out-performance for 5 years. A revised mechanism is set out in Table A1.2 below.

A1.38 The revised approach takes account of the interaction between retention of benefits beyond 2010 and the level of targets beyond 2010. For example, if targets were not updated at the next price review, any incremental out-performance would be retained without further adjustment. The mechanism set out in Table A1.2 achieves this. For the avoidance of doubt, Ofgem expects that targets will be updated at the next price review. Neither Table 2 nor any other part of this appendix is intended to provide any indication of how targets will be updated at the next review.

A1.39 The mechanism set out in Table A1.2 also recognises that 2009/10 performance will not be known when the price controls are reset for the period 2010 onwards.

A1.40 In respect of losses generally, Ofgem proposes that any units restated will attract the value of the incentive payment relevant to the year in which these units were purchased and distributed rather than the year that the restatement occurs.

Pension costs

A1.41 The pension allowances determined for the purposes of establishing these proposals are set out in Appendix 3 of this document as monetary amounts (in 2002/03 prices), separately for normal contributions and deficit recovery. These include both defined benefit schemes and defined contribution schemes. Also set out are proportions of the pension deficit allocated to the distribution business and the amount of pension deficit disallowed in respect of ERDCs.

A1.42 The amount of deficit recovery allowed under the distribution price control can be calculated as:

$$\text{deficit allowed} = \frac{(\text{deficit} \times \text{proportion to distribution}) - (ERDCdisallowed)}{(\text{deficit})}$$

A1.43 For example, if the deficit is £100m, 80 per cent of the deficit is allocated to distribution and the distribution share of ERDCs disallowed is £20m, then the allowed proportion will be calculated as:

$$allowed = \frac{(£100m \times 0.80) - £20m}{£100m}$$

A1.44 The relevant proportions are set out in Chapter 8.

A1.45 In considering actual pension contributions, the relevant amounts will be actual cash contributions attributable to the distribution business and paid into the relevant pension scheme. Where relevant, this will include statutory contributions to the Pension Protection Fund.

A1.46 Ofgem anticipates the companies' actual pension contributions will differ from those projected as part of the price control in response to changing circumstances. Therefore the amount of normal contributions for distribution employees in both defined benefit schemes and defined contribution schemes (including related party employees working on distribution, but excluding metering for this purpose) plus the total deficit contribution for defined benefit schemes multiplied by the allowed proportion is likely to differ from the pension allowance.

A1.47 The basis on which pensions allowances have been proposed at this review means that the extent to which the pension contributions differ from the pension allowances will be offset against any future pension costs in determining future pension allowances. Any such adjustments would be net of tax, to the extent that the over or under payment has reduced or increased tax payable.

A1.48 Ofgem intends that the treatment of pension costs at future reviews would be in accordance with the principles summarised in Chapter 8 and set out in previous consultation papers. For example, any ERDCs that are incurred after 1 April 2004 will be wholly for the account of shareholders. This can be achieved by reducing the amount of contributions paid by the amount of any ERDCs before considering over- or under-funding.

A1.49 As noted in the RAV calculations section above, 57.7 per cent of actual pension contributions in the period 2005-10 will be included in the RAV. This will, of itself, mean that future revenues will be affected by any over- or under-funding relative to the allowance. Any adjustments for over- or under-funding will not double-count this impact.

A1.50 Ofgem also intends that the pension allowances and contributions will be removed from capital expenditure prior to any consideration of rolling incentive arrangements.

Bad debts

A1.51 The treatment of bad debts incurred by network operators due to the failure of a licensed supplier is currently subject to consultation. It is expected that the decision arising from that consultation will need to be reflected either in the way in which allowances are set at the next price review or in distribution licence modifications, depending on the outcome.

Tax

A1.52 For the reasons given in Chapter 8, Ofgem is not proposing a general risk-sharing or incentive mechanism for tax.

A1.53 However, Ofgem does propose to claw back the tax benefits of gearing in excess of that assumed in the cost of capital calculation. This will only apply where both of the following conditions apply in a given year:

- regulatory gearing (net debt to RAV) on 31 March exceeds 57.5 per cent; and
- actual interest payable exceeds interest charges in the price control financial model, for the year ending 31 March.

A1.54 Where both conditions apply, Ofgem would expect to claw back at the next price control review the tax benefits gained from the difference in interest charges. If only one or neither of these conditions apply, no adjustment would be made in respect of that year.

The distributed generation incentive

A1.55 The distributed generation incentive provides for recovery of capital and operating expenditure in relation to distributed generation. Operating costs incurred in the period 2005-10 are provided for through an allowance of £1/kW connected. Ofgem would expect to reconsider the treatment of operating costs to be incurred after 2010 at the next price review.

A1.56 For capital expenditure incurred in the period 2005-10 in respect of distributed generation, 80 per cent of costs are intended to be passed-through and remunerated through a revenue entitlement over the following 15 years. This will include capital expenditure in respect of a Registered Power Zone (RPZ). It will not include any capital expenditure or associated indirect costs already included in RAV additions and where capital expenditure is incurred for the benefit of both demand and generation, costs shall be apportioned accordingly. Where related assets are not used by generators but are used by demand customers, the DNO concerned may, by agreement with Ofgem, transfer the undepreciated value of capex to the RAV.

A1.57 In addition, distribution companies will be entitled to revenue of £1.50/kW connected (or £2/kW in SSE-Hydro's area). It is intended that for each vintage of generating capacity connecting in the period 2005-10 this value is fixed for 15 years, subject to three conditions set out below.

A1.58 Generation connected in a Registered Power Zone will give rise to a further £3/kW revenue entitlement for a period of 5 years after the year of connection, subject to a cap of £0.5m per annum per licensee.

A1.59 The three conditions referred to above are:

- the cap and floor (see below);

- the application by the DNO of other aspects of the distributed generation incentive package as set out in Chapter 5, including in particular the network unavailability rebate and exposure to capacity risk. If any DNO does not apply these arrangements, it will face lower risks than intended when the price control was proposed and Ofgem may therefore reduce the implied return, by reducing the incentive rate and the cap on returns; and

- a right to review the incentive rate and pass-through arrangement prior to 2010 if it appears to be having unintended consequences (other than simply high or low returns to the DNO, which are addressed through the cap and collar). Such a review would only apply prospectively to costs incurred or capacity connecting at least six months after the review was announced and would not affect entitlements to revenues arising before this date, except by agreement with the DNO.

A1.60 As noted in Chapter 5, the distributed generation incentive includes a cap and floor on the rate of return that DNOs are able to earn in relation to the connection of distributed generation. Ofgem intends that these arrangements will be applied by projecting revenues arising in relation to assets installed over the period 2005 to 2010 (using projections for years where data is not available when the calculation is performed) over the full life of those assets to determine the internal rate of return (IRR). The IRR will be evaluated against the proposed cap and floor of the incentive scheme, which is twice the real pre-tax equivalent cost of capital (13.8%) and real cost of debt used in this review (4.1%) respectively. If the IRR exceeds (is below) the cap (floor), an adjustment to revenues after 2010 would be made to reduce (increase) the IRR to the level of the cap (floor).

A1.61 For the purposes of this calculation, Ofgem will exclude both the operating costs that have been incurred by the DNO in relation to those DG assets and the operation and maintenance allowance provided for under the scheme.

A1.62 If the capital expenditures associated with RPZs can be robustly identified separately from other distributed generation costs, they will be excluded from this calculation along with the premium revenues applying to RPZs. However, if such separation cannot be made robustly, both the capital expenditure and the premium revenues associated with RPZs will be included in the IRR calculation.

Table A1.1: Rolling capex incentive

Real 2002/03 prices

year ending March		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	NPV
Vanilla WACC	6.90%											
Actual Capital Expenditure in Year		100.0	0.0	100.0	100.0	100.0						£323.61
Allowance in Year		100.0	100.0	100.0	100.0	100.0						£411.12
Out performance/(underperformance)		0.0	100.0	0.0	0.0	0.0						£87.51
Depreciation factors												
(Out performance)/underperformance depreciation factor			5%	5%	5%	5%	5%	5%	5%	5%	5%	
Cumulative depreciation factor							25%	25%	25%	25%	25%	
Incentive Scheme Roller												
Opening balance		0.0	0.0	100.0	95.0	90.0	85.0	80.0	0.0	0.0	0.0	
Out performance/(underperformance)		0.0	100.0	0.0	0.0	0.0						
(Out performance)/underperformance depreciation			0.0	-5.0	-5.0	-5.0	-5.0	-5.0	0.0	0.0	0.0	
(Expired out performance)/ underperformance							0.0	-75.0	0.0	0.0	0.0	
Closing balance		0.0	100.0	95.0	90.0	85.0	80.0	0.0	0.0	0.0	0.0	
Incentive Payment												
Depreciation allowance		0.00	0.00	5.00	5.00	5.00	5.00	5.00	0.00	0.00	0.00	
Return allowance		0.00	3.45	6.73	6.38	6.04	5.69	2.76	0.00	0.00	0.00	
Implied capex reward (="reward")		**0.00**	**3.45**	**11.73**	**11.38**	**11.04**	**10.69**	**7.76**	**0.00**	**0.00**	**0.00**	£41.27
Cost saving (="saving")	£87.51											
Reward/saving (="retention")	47%											
Sliding scale (="scheme")	30%											
Excess reward = (retention-scheme) x saving	-£15.02											
Additional incentive adjustment		0.00	0.00	0.00	0.00	0.00	**-22.41**	0.00	0.00	0.00	0.00	-£15.02
Total capex roller adjustment							**-11.72**	**7.76**	**0.00**	**0.00**	**0.00**	
Total reward		0.00	3.45	11.73	11.38	11.04	-11.72	7.76	0.00	0.00	0.00	£26.25
Total retention	30%											

Table A1.2

Losses incentive

		DPCR 4					DPCR 5				
		2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Units distributed		100	100	100	100	100					
Target loss percentage		5%	5%	5%	5%	5%					
Allowed losses (AL)		5	5	5	5	5	4	4	4	4	4
Recorded		4	6	3	3	tbd					
average target for DPCR5		na	na	na	na	4					
Out performance[1]		1	-1	2	2	1					
DPCR 4 Incentive payment	**£m**	**4.8**	**-4.8**	**9.6**	**9.6**	**tbd**					
Incremental change (05/06)[2]		1	1	1	1	1					
Incremental change (06/07)		-	-2	-2	-2	-2	-2				
Incremental change (07/08)		-	-	3	3	3	3	3			
Incremental change (08/09)		-	-	-	0	0	0	0	0		
Incremental change (average)		-	-	-	-	-1	-1	-1	-1	-1	
Sum of changes		1	-1	2	2	1	0	2	-1	-1	0
Incentive adjustment	**£m**	-	-	-	-	-	**0**	**9.6**	**-4.8**	**-4.8**	**0**
Adjusted incentive payment[3]	£m	**4.8**	**-4.8**	**9.6**	**9.6**	**tbd**	**0**	**9.6**	**-4.8**	**-4.8**	**0**

[1] Out performance is assumed to be zero from April 2009 onwards.

[2] Out performance is assumed to be zero in 2004/05

[3] No incentive adjustment applies for the period 2005/06 to 2009/10.

Appendix 2 Metering activities

The table below sets out an indicative list of the activities that are in the chargeable activities for the purposes of MOp revenue control. Those chargeable activities set out in the single phase column but not duplicated in the poly phase or CT columns cover all chargeable activities of that type not just those performed on single phase meters.

Type of Chargeable Activity		
Single Phase	**Poly Phase**	**CT**
Install for New Connection Single Phase meter	Install for New Connection Polyphase meter	Install for New Connection CT meter
Install for Functionality Change Single Phase Meter	Install for Functionality Change Poly Phase Meter	Install for Functionality Change CT Meter
Visit for meter faults Single Phase Meter	Visit for meter faults Poly Phase Meter	Visit for meter faults CT Meter
Replace for Recertification Single Phase Meter	Replace for Recertification Poly Phase Meter	Replace for Recertification CT Meter
Replace for Meter Damage Single Phase Meter	Replace for Meter Damage Poly Phase Meter	Replace for Meter Damage CT Meter
Reposition a Single Phase meter	Reposition a Poly Phase meter	Reposition a CT meter
Fit Single Phase Check Meter	Fit Poly Phase Check Meter	Fit CT Check Meter
Meter accuracy test on Single Phase Meter	Meter accuracy test on Poly Phase Meter	Meter accuracy test on CT Meter
All reseal a meter		
All Install Timeswitch/Teleswitch		
Single Reprogramme PPM (not part of a bulk tariff change)		
All de-energise or re-energise a meter		
All abortive Visits (an organised visit not cancelled with sufficient notice by Supplier for the DNO to reorganise resources)		
Visit PPM Consumer (a miscellaneous visit to a PPM consumer not covered in other categories)		
All attend visit with DTI Inspector (including Meter Change)		

Appendix 3 Detailed tables

Table A1: Comparison of components of operating costs to the September Update (£m, 2002/03 prices)

	Table A3			Table A4			Table A6			Table A6		
	Normalised Controllable Costs + Faults			Adjusted Normalised Controllable Costs + Faults			DPCR4 5 Year Average Opex Allowance			DPCR4 5 Year Average Total Opex Allowance		
	Final Proposals	September Paper		Final Proposals	September Paper		Final Proposals	September Paper		Final Proposals	September Paper	
	Normalised Opex + Total Faults	**Normalised Opex + Total Faults**	**Difference Note (1)**	**Adjusted Normalised Controllable Costs + Faults**	**Adjusted Normalised Controllable Costs + Faults**	**Difference Note (2)**	**DPCR4 5 Year Average Opex Allowance**	**DPCR4 5 Year Average Opex Allowance**	**Difference Note (2)**	**DPCR4 5 Year Average Total Opex Allowance**	**DPCR4 5 Year Average Total Opex Allowance**	**Difference Note (3)**
DNO	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
CN - Midlands	66.6	67.0	(0.4)	63.9	63.9	-	60.9	59.5	1.4	75.5	74.1	1.4
CN - East Midlands	62.8	63.0	(0.2)	60.7	60.7	-	65.1	64.0	1.1	82.4	81.5	0.9
United Utilities	70.2	70.4	(0.1)	67.1	67.1	-	58.5	55.5	3.0	70.1	66.2	3.9
CE - NEDL	40.8	40.5	0.3	38.2	38.2	-	42.8	43.3	(0.5)	54.3	54.3	0.0
CE - YEDL	54.8	54.2	0.6	52.1	52.1	-	51.7	52.3	(0.6)	64.1	63.3	0.8
WPD - South West	54.2	54.2	0.0	51.3	51.3	-	46.6	48.0	(1.4)	61.2	61.4	(0.1)
WPD - South Wales	38.0	38.0	(0.0)	36.1	36.1	-	39.6	40.2	(0.5)	48.6	49.2	(0.6)
EDF - LPN	62.4	62.4	(0.1)	59.4	59.4	-	52.0	50.6	1.5	72.0	68.9	3.1
EDF - SPN	69.0	68.5	0.4	66.1	66.1	-	51.5	50.3	1.2	60.8	56.7	4.1
EDF - EPN	88.1	86.9	1.2	84.4	84.4	-	81.6	82.6	(1.0)	94.9	95.0	(0.1)
SP Distribution	63.3	62.7	0.6	57.5	57.5	-	55.6	56.0	(0.5)	77.8	78.0	(0.2)
SP Manweb	53.3	52.6	0.7	51.4	51.4	-	46.2	47.0	(0.8)	55.5	55.9	(0.4)
SSE - Hydro	36.1	36.4	(0.2)	32.9	32.9	-	37.7	37.6	0.1	50.6	50.3	0.2
SSE - Southern	61.6	62.6	(1.0)	58.5	58.5	-	69.0	68.1	0.9	102.7	101.2	1.5
Total	**821.1**	819.3	1.7	**779.6**	779.6	-	**758.9**	755.0	3.9	**970.5**	955.9	14.6

Notes:
(1) Normalised Opex + Total Faults has been updated for the latest view on opex pension numbers.

(2) There has been no change to Adjusted Normalised Controllable Costs + Faults since the September Update as the pension change in note (1) has no effect due to pensions being added and removed before the efficiency score is applied.

(2) The increase in DPCR4 5 Year Average Opex Allowance is due to the updated pensions number discussed in point (1) above and the following:
- introduction of a glidepath for singleton DNOs, whereby each singleton DNO must achieve 50% of their efficiency target by 2004/05 with the remaining 50% to be achieved by the end of the 5th year after the year of merger. In the case of UUE, where no merger has been announced, 100% efficiency is assumed to be achieved by 2010/11. An adjustment to higher of base costs or singleton upper quartile was also performed, with the only effect being on EME.
- inclusion of an extra London regional allowance for LPN,
- reallocating WPD South West and South Wales Quality of Supply Reward to be added back after the 23.5% capitalisation adjustment has been applied.

(3) The increase in DPCR4 5 Year Average Total Opex Allowance is due to the points identified in Note (2) above, together with a change in the methodology in respect of the capitalised fault adjustment. For the September Update, capitalised faults was calculated as a percentage of the Average DPCR4 Opex + Total Faults Allowance (ie. excluding QoS, Trees and Storms). For the Final Proposals the capitalised faults has been calculated as a % of DPCR4 5 Year Average Opex Allowance (ie. including QoS, Trees and Storms). In addition, the % allocated to capex has changed from 26% to 23.5%. This change in % ensures the effect on cash flow is minimised.

Table A2: Movement from the September Update average total opex allowance (£m, 2002/03 prices)

	Notes	£'m
September Update Proposed Average Total Opex Allowance		956
Movements:		
- Singleton Glidepath		7
- London Additional Regional Allowance		2
- Impact of change in capitalised faults methodology	1	1
- Impact of updating pensions for normalisation		(3)
- Impact of updating total pensions opex allowance		8
Final Proposals Average Total Opex Allowance		**971**

Notes:
1. Impact of change in capitalised faults methodology is offset over time as this amount is then allowed as capex. The change is due to applying the capitalisation % to a different opex + total faults number and changing the capitalisation % from 26% to 23.5%.

Table A3: Detailed 2003/04 Normalisation Adjustments (£m, 2002/03 prices)

							Normalisation adjustments																	
	DNO	DPCR4 Controllable costs (note 1)	Late Adj. to COC	Fault costs expensed**	Atypical items and one offs (note 1)	Recurring controllable costs	Inter/Intra Coy margins	Insurance Costs	Average Forecast Non-op Spend	Metering	Lane rentals / Congestion Charges	Deduct actual pension charge	Include Ofgem pension charge	Regional Factors and cost differences	132kV cost adj - Scotland	Capitalisation policies	On-going DMS costs	Revenue protection adjustment	Remove R&D	DPCR4 Normalised Controllable costs	Normalised Faults	Overhead allocation (5% band)	DPCR4 Normalised Controllable Costs + Faults
		£m		£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
1	CN - Midlands	54.3	0.0	(13.2)	1.6	42.7	(0.7)	0.0	0.0	(5.1)	0.0	(1.8)	2.7	0.0	0.0	0.1	0.0	0.0	(0.3)	37.6	25.1	3.9	66.6
2	CN - East Midlands	71.6	1.5	(34.9)	(5.6)	32.6	0.0	(1.5)	1.5	(6.8)	0.0	(0.4)	2.1	0.0	0.0	2.2	0.9	0.0	(0.3)	30.3	32.5	0.0	62.8
3	United Utilities	31.0	0.0	(15.0)	19.9	35.9	0.0	0.0	7.2	(4.7)	0.0	(0.6)	3.2	0.0	0.0	1.5	0.8	(0.4)	(0.3)	42.6	31.2	(3.6)	70.2
4	CE - NEDL	36.3	0.0	(4.2)	(0.9)	31.2	(0.4)	(0.8)	3.1	(2.8)	(0.2)	(1.0)	2.6	0.0	0.0	2.1	2.3	(0.4)	(0.2)	35.6	12.8	(7.6)	40.8
5	CE - YEDL	47.5	0.0	(6.4)	(0.5)	40.6	(0.0)	(1.4)	3.6	(6.0)	0.0	(0.9)	2.7	0.0	0.0	2.3	3.5	(0.4)	(0.4)	43.5	20.4	(9.2)	54.8
6	WPD - South West	29.8	0.0	(8.2)	9.1	30.7	(1.1)	0.0	7.4	(5.4)	0.0	(1.0)	2.9	0.0	0.0	0.1	0.2	0.0	(0.1)	33.8	20.6	(0.2)	54.2
7	WPD - South Wales	34.7	0.0	(3.6)	(3.5)	27.6	(0.2)	0.0	5.5	(4.0)	0.0	(1.4)	1.9	0.0	0.0	0.3	0.2	0.0	(0.1)	29.9	8.2	(0.1)	38.0
8	EDF - LPN	56.5	0.0	(15.8)	(3.8)	36.9	(5.1)	0.0	7.0	(3.6)	(1.3)	(1.5)	2.9	(4.4)	0.0	0.0	0.0	0.0	(0.0)	30.9	25.9	5.6	62.4
9	EDF - SPN	61.2	0.0	(9.6)	1.3	52.9	0.0	(1.7)	6.7	(8.1)	0.0	(4.5)	2.8	0.0	0.0	0.0	0.0	(0.4)	(0.0)	47.7	21.3	0.0	69.0
10	EDF - EPN	78.9	0.0	(22.0)	(5.6)	51.3	(1.5)	(2.6)	9.8	(8.9)	0.0	(2.2)	3.7	0.0	0.0	0.0	0.0	0.0	(0.0)	49.5	32.4	6.1	88.1
11	SP Distribution	38.4	1.5	(7.2)	(4.3)	28.4	(2.1)	0.0	0.0	(3.3)	0.0	(1.7)	2.0	0.0	3.2	0.0	0.0	0.0	(0.1)	26.3	29.0	7.9	63.3
12	SP Manweb	40.4	0.0	(8.6)	(2.2)	29.6	(2.3)	0.0	0.0	(5.2)	0.0	(1.6)	1.9	0.0	0.0	0.0	0.0	0.0	(0.1)	22.3	30.0	1.0	53.3
13	SSE - Hydro	36.4	0.0	(3.9)	(0.4)	32.1	(0.8)	(0.4)	0.3	(2.7)	0.0	(1.7)	1.7	(1.4)	1.6	1.0	0.0	0.0	(0.1)	29.5	6.6	0.0	36.1
14	SSE - Southern	60.2	0.0	(15.2)	(0.4)	44.6	(0.9)	(0.6)	0.7	(6.3)	0.0	(3.1)	3.1	0.0	0.0	1.0	0.0	0.0	(0.1)	38.4	20.4	2.8	61.6
	Total	**677.2**	**3.0**	**(167.8)**	**4.7**	**517.1**	**(15.1)**	**(9.0)**	**52.8**	**(72.9)**	**(1.5)**	**(23.4)**	**36.1**	**(5.8)**	**4.8**	**10.6**	**7.9**	**(1.6)**	**(2.1)**	**498.0**	**316.5**	**6.6**	**821.1**

Notes:

1 This information has been sourced from the 'Standard Controllable Costs' schedule completed and agreed with individual DNOs in Dec '03. Adjustments have been made to remove 'normalisation type adjustments' included in the 'Standard Controllable Costs' schedule and present them in the appropriate 'Normalisation category' available. This has been necessary to aid in the transparency of adjustments when reviewing normalised operating costs across all the DNOs.

2 The November Final Proposals normalisation adjustments have been updated for the latest pension numbers. No other changes have been made since the September Update.

Table A4: Calculation of Adjusted Normalised controllable costs plus total fault costs (£m, 2002/03 prices)

DNO	DPCR4 Normalised Controllable Costs + Faults	Non-allowable elements: Reverse 132kV adj - Scotland Opex	Non-allowable elements: Reverse 132kV adj - Scotland Faults	Non-allowable elements: Remove Ofgem Pension Cost Opex + Total Faults	DPCR4 Adjusted Normalised Controllable Costs + Faults
	£m	£m	£m	£m	£m
CN - Midlands	66.6	-	-	(2.7)	63.9
CN - East Midlands	62.8	-	-	(2.1)	60.7
United Utilities	70.2	-	-	(3.2)	67.1
CE - NEDL	40.8	-	-	(2.6)	38.2
CE - YEDL	54.8	-	-	(2.7)	52.1
WPD - South West	54.2	-	-	(2.9)	51.3
WPD - South Wales	38.0	-	-	(1.9)	36.1
EDF - LPN	62.4	-	-	(2.9)	59.4
EDF - SPN	69.0	-	-	(2.8)	66.1
EDF - EPN	88.1	-	-	(3.7)	84.4
SP Distribution	63.3	(3.2)	(0.5)	(2.0)	57.5
SP Manweb	53.3	-	-	(1.9)	51.4
SSE - Hydro	36.1	(1.6)	-	(1.7)	32.9
SSE - Southern	61.6	-	-	(3.1)	58.5
Total	**821.1**	**(4.8)**	**(0.5)**	**(36.1)**	**779.6**

Notes:

1. Regional factors have not been reversed at this stage in the calculation of the allowance. Instead, the efficiency score is to be applied to normalised controllable costs + total faults, including the regional factor adjustment. The regional factor adjustment will then be reversed after the efficiency score has been applied.

Table A5: Calculation of Base Operating Costs plus Total Fault Costs Allowance (£m, 2002/03 prices)

		Base Analysis 14 DNOs		2000-2010 Total Cost Analysis 14 DNOs		Merged Analysis 9 Groups						
DNO	**2002/03 Adjusted Normalised Controllable Costs + Faults**	**Efficiency % CSV 3**	**2002/03 Efficient Costs (Upper Quartile)**	**Efficiency % CSV 3**	**2002/03 Efficient Costs (Upper Quartile)**	**Efficiency % CSV 3**	**2002/03 Efficient Costs (Upper Quartile)**	**Average 2002/03 Efficient Costs (Upper Quartile)**	**Adjustment to higher of Average or Base 2002/03 Efficient Costs**	**Regional Factor Adjustment**	**Adjusted 2002/03 Efficient Costs (Upper Quartile)**	**Average DPCR4 Opex + Total Faults Allowance (1.5% Frontier Shift)**
	A	B	C (= A x B)	D	E (= A x D)	F	G (= A x F)	H (= Avge(C,E,G)	I (= H - C)	J	L (= C + I + J + K)	M
	£m		£m		£m		£m	£m	£m	£m	£m	£m
CN - Midlands	63.9	88%	56.0	88%	56.0	88%	56.3	56.1	0.1	-	56.1	54.8
CN - East Midlands	60.7	100%	60.6	100%	60.8	103%	62.5	61.3	0.7	-	61.3	59.6
United Utilities	67.1	81%	54.5	83%	55.6	81%	54.4	54.8	0.3	-	54.8	55.4
CE - NEDL	38.2	106%	40.4	98%	37.5	95%	36.1	38.0	-	-	40.4	38.6
CE - YEDL	52.1	97%	50.5	100%	52.0	95%	49.2	50.6	0.1	-	50.6	48.4
WPD - South West	51.3	83%	42.4	90%	45.9	77%	39.2	42.5	0.1	-	42.5	40.7
WPD - South Wales	36.1	97%	35.1	98%	35.2	77%	27.6	32.7	-	-	35.1	33.6
EDF - LPN	59.4	72%	43.1	73%	43.2	86%	51.3	45.8	2.8	7.8	53.6	51.3
EDF - SPN	66.1	74%	49.1	77%	51.1	71%	46.9	49.0	-	-	49.1	48.6
EDF - EPN	84.4	89%	75.2	92%	77.4	86%	72.8	75.2	-	-	75.2	71.9
SP Distribution	57.5	90%	51.6	100%	57.7	84%	48.1	52.5	0.9	-	52.5	50.2
SP Manweb	51.4	84%	43.0	81%	41.6	84%	42.9	42.5	-	-	43.0	41.1
SSE - Hydro	32.9	100%	33.0	99%	32.5	106%	34.8	33.4	0.4	1.6	35.0	33.5
SSE - Southern	58.5	110%	64.5	100%	58.7	106%	61.9	61.7	-	-	64.5	61.6
Total	**779.6**		699.1		705.2		684.0	696.1	5.3	9.4	713.8	689.2

Notes:

1 The purpose of this table is to calculate Adjusted 2002/03 Efficient Costs (Upper Quartile) on the basis of the higher of Average or Base 2002/03 Efficient Costs applying the efficiency scores from the regression of the 3 methods - Base Analysis 14 DNOs, Total Cost Analysis 14 DNOs, Merger Analysis 9 Groups to adjusted normalised controllable costs + faults.

2 The average allowance is shown after a frontier shift of 1.5% p.a. has been applied from 1 April 2005.

Table A6: Average Operating Cost plus Total Fault Cost Allowance (£m, 2002/03 prices)

DNO	Average DPCR4 Opex + Total Faults Allowance (1.5% Frontier Shift)	Opex Allowance Buildup: Storm Insurance and Atypicals	Activity Level Adjustment - Tree Cutting	QoS Average Opex Allowance	DPCR4 5 Year Average Opex Allowance (1.5% Frontier Shift)	Ofgem Licence Fee Average	Network Rates Average	Shetland (note 2)	QoS Reward	Capitalisation faults and non operational capex (note 1)	DPCR4 5 Year Average Total Opex Allowance excl. Pensions (1.5% Frontier Shift)	Total Pension Allowance	Capitalised Pension Allowance Adjustment (note 3)	DPCR4 5 Year Average Total Opex Allowance (1.5% Frontier Shift)
	£m	£m	£m	£m	£m	£m	£m	£m	£m		£m	£m	£m	£m
CN - Midlands	54.8	2.3	1.9	1.8	60.9	1.1	21.0	-		(14.3)	68.6	16.2	(9.4)	75.5
CN - East Midlands	59.6	2.3	1.1	2.1	65.1	1.1	25.9	-		(15.3)	76.9	13.1	(7.5)	82.4
United Utilities	55.4	1.3	-	1.8	58.5	1.1	17.5	-		(13.7)	63.3	16.0	(9.2)	70.1
CE - NEDL	38.6	1.9	1.1	1.2	42.8	0.7	13.4	-		(10.1)	46.8	17.7	(10.2)	54.3
CE - YEDL	48.4	1.6	0.1	1.7	51.7	1.0	19.1	-		(12.2)	59.6	10.5	(6.0)	64.1
WPD - South West	40.7	1.6	2.7	1.6	46.6	0.7	17.2	-	1.5	(10.9)	55.0	14.8	(8.5)	61.2
WPD - South Wales	33.6	2.0	3.0	1.1	39.6	0.5	13.1	-	0.4	(9.3)	44.3	10.2	(5.9)	48.6
EDF - LPN	51.3	-	-	0.8	52.0	1.0	21.9	-		(12.2)	62.7	21.9	(12.7)	72.0
EDF - SPN	48.6	1.1	0.4	1.4	51.5	1.0	11.6	-		(12.1)	52.1	20.6	(11.9)	60.8
EDF - EPN	71.9	3.3	4.0	2.4	81.6	1.6	25.6	-		(19.2)	89.6	12.5	(7.2)	94.9
SP Distribution	50.2	1.8	1.9	1.7	55.6	0.9	32.4	-		(13.1)	75.8	4.8	(2.7)	77.8
SP Manweb	41.1	1.2	2.3	1.6	46.2	0.7	12.8	-		(10.9)	48.8	15.7	(9.1)	55.5
SSE - Hydro	33.5	1.4	1.8	1.0	37.7	0.3	12.7	7.1		(8.9)	48.9	3.9	(2.3)	50.6
SSE - Southern	61.6	2.7	2.3	2.4	69.0	1.3	35.9	-		(16.2)	90.0	30.2	(17.5)	102.7
Total	689.2	24.5	22.4	22.7	758.9	13.0	280.0	7.1	1.9	(178.3)	882.5	208.2	(120.1)	970.5

Notes:

1. The capitalised faults and non operational capex has been calculated as 23.5% of Average DPCR4 Opex + Total Faults Allowance after applying the 1.5% Frontier Shift. The June Initial Proposals applied the capitalised fault and non-operational capex % to the DPCR4 5 Year Average Opex Allowance (after applying the 1.5% frontier shift), thereby applying the % to the opex allowance buildup costs as well. This has been corrected for this paper.

2. An allowance for the costs of balancing in Shetland has been allowed for SSE Hydro.

3. Capitalised pensions are 57.7% of the total pensions allowance.

Table A7: Adjusted DNO Base Case Opex forecasts (2005-10 totals, 2002/03 prices)

DNO	CN - Midlands	CN - East Midlands	United Utilities	CE - NEDL	CE - YEDL	WPD - South West	WPD - South Wales	EDF-LPN	EDF-SPN	EDF-EPN	SP Distribution	SP Manweb	SSE - Hydro	SSE - Southern	Total
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
Total Opex and Cost of Sales per March 2004 Paper	856	817	750	480	609	648	478	836	807	998	807	540	453	969	
Difference between March 2004 Paper and FBPQ	6	-	36	8	12	(2)	(1)	16	0	19	-	(1)	10	18	
Total Opex and Cost of Sales per FBPQ	**862**	**817**	**786**	**487**	**621**	**646**	**477**	**852**	**807**	**1,017**	**807**	**540**	**463**	**987**	
Less Non-Controllable Costs per FBPQ															
- exit charges	(89)	(71)	(81)	(72)	(69)	(25)	(20)	(110)	(89)	(123)	(255)	(72)	(53)	(103)	
- NTR costs	(88)	(39)	(29)	(10)	(14)	(20)	(15)	-	(17)	-	(48)	(42)	(6)	(33)	
- other costs of sale	-	-	-	(4)	-	(22)	(5)	-	-	-	-	-	(5)	(6)	
- depreciation	(241)	(220)	(253)	(119)	(169)	(205)	(156)	(218)	(190)	(295)	(188)	(145)	(149)	(302)	
- network rates	(117)	(128)	(98)	(64)	(108)	(85)	(65)	(104)	(75)	(126)	(124)	(75)	(42)	(171)	
- Ofgem licence fee	(6)	(7)	(10)	(4)	(5)	-	-	(6)	(5)	(8)	(7)	(5)	(2)	(8)	
Total Non-Controllable Costs per FBPQ	**(541)**	**(464)**	**(471)**	**(273)**	**(366)**	**(357)**	**(261)**	**(437)**	**(375)**	**(552)**	**(622)**	**(338)**	**(255)**	**(621)**	
Apply 2002/03 Opex Normalisation Adjusments															
- less margins	(4)	-	(10)	(2)	-	(7)	(2)	(26)	-	(8)	(11)	(12)	(5)	(8)	
- less pension deficit	(15)	(19)	(25)	-	-	(79)	(55)	(135)	(115)	(15)	-	-	-	(24)	
- less normal pensions	(14)	(8)	(18)	(9)	(10)	(20)	(16)	(12)	(29)	(18)	(11)	(10)	(12)	(27)	
- less metering	(26)	(13)	(24)	(14)	(30)	(27)	(20)	(18)	(41)	(45)	(17)	(26)	(14)	(32)	
- lane rentals	(18)	(42)	-	(1)	-	-	-	(12)	(3)	(5)	-	-	-	-	
- add average forecast non-operational capex spend	-	8	36	16	-	44	21	35	34	16	-	-	2	4	
- add capitalised faults (less margins)	64	42	107	47	94	78	36	80	59	76	89	51	13	37	
- apply overhead adjustment	20	-	(18)	(38)	(46)	(1)	(1)	28	-	31	40	5	-	14	
Total Normalisation Adjustments	**8**	**(32)**	**49**	**(2)**	**8**	**(12)**	**(36)**	**(58)**	**(94)**	**33**	**91**	**9**	**(16)**	**(35)**	
Total Adjusted DPCR4 Opex Forecast	**329**	**321**	**364**	**212**	**263**	**277**	**180**	**357**	**338**	**498**	**277**	**210**	**192**	**330**	
Adjusted DPCR4 Average Forecast	**66**	**64**	**73**	**42**	**53**	**55**	**36**	**71**	**68**	**100**	**55**	**42**	**38**	**66**	**830**

Notes:
1. Metering costs for CN - East have been adjusted to eliminate a double count of metering costs.

Table A8: Increase in allowance for vegetation management

Increase in tree cutting allowance

DNO	CSV	Upper Quartile Cost per CSV	Annual Cost implied using Upper Quartile Cost x CSV (i.e. costs allowed in regressed costs)	Average Annual Model Costs	Increased Allowance (Higher of regressed or modelled costs)	Increase in allowance for change in activity level	Increase in allowance for change in activity level (Initial proposals)
		£k	£m	£m	£m	£m	£m
CN - Midlands	21.9	125	2.7	4.6	4.6	1.9	1.0
CN - East Midlands	24.1	125	3.0	4.1	4.1	1.1	0.1
United Utilities	21.2	125	2.7	2.6	2.7	-	-
CE - NEDL	14.2	125	1.8	2.8	2.8	1.1	0.5
CE - YEDL	19.2	125	2.4	2.5	2.5	0.1	-
WPD - South West	15.1	125	1.9	4.6	4.6	2.7	2.1
WPD - South Wales	11.1	125	1.4	4.4	4.4	3.0	2.5
EDF - LPN	15.2	125	-	-	-	-	-
EDF - SPN	18.3	125	2.3	2.7	2.7	0.4	-
EDF - EPN	32.0	125	4.0	8.0	8.0	4.0	2.6
SP Distribution	21.0	125	2.6	4.5	4.5	1.9	1.0
SP Manweb	15.0	125	1.9	4.2	4.2	2.3	1.7
SSE - Hydro	10.8	125	1.3	3.1	3.1	1.8	1.3
SSE - Southern	26.6	125	3.3	5.6	5.6	2.3	1.1
Total						22.4	13.9

Table A9: Base case capital expenditure

DNO Capex forecasts and PB Power's view

DNO	**DPCR3 ACT/FCST**	**Adjusted DPCR4 FCST** (Base case) Note 1	*% Inc/(dec) over DPCR3 act/fcst.*	**PB Power view of DPCR4 capex** (Base case)	*% Inc/(dec) over DPCR3 act/fcst.*	*Adjusted DPCR4 forecast as % of Allowance*
	£m	£m		£m		
CN - Midlands	336	485	*44%*	444	*32%*	*109%*
CN - East Midlands	301	480	*60%*	445	*48%*	*108%*
United Utilities	347	457	*32%*	439	*26%*	*104%*
CE - NEDL	228	268	*18%*	263	*15%*	*102%*
CE - YEDL	242	358	*48%*	346	*43%*	*103%*
WPD - South West	221	269	*22%*	269	*22%*	*100%*
WPD - South Wales	191	171	*-11%*	171	*-11%*	*100%*
EDF - LPN	260	536	*106%*	398	*53%*	*135%*
EDF - SPN	283	479	*69%*	433	*53%*	*111%*
EDF - EPN	438	745	*70%*	609	*39%*	*122%*
SP Distribution	253	375	*48%*	335	*32%*	*112%*
SP Manweb	240	455	*90%*	363	*51%*	*126%*
SSE - Hydro	165	208	*26%*	189	*15%*	*110%*
SSE - Southern	375	511	*36%*	511	*36%*	*100%*
Total	3,882	5,798	49%	5,216	34%	111%

Notes

1 Forecasts are unchanged from the September Update except:

The three EDF companies have adjusted their forecasts downwards and the amounts removed by Ofgem relating to fluid filled cable replacement have been revised.

The two Scottish Power companies have adjusted their forecasts downwards.

Table A10:

Derivation of DPCR 4 Capital Expenditure Allowances (£m, 2002/03 Prices)

DNOs	Base Capex	Less Pensions Component	Base Capex less Pensions	Sliding Scale	Quality of Service Allowance	Capitalised Faults and Non Op Capex	Total Before Pensions	Capitalised Pensions	Total Capex Allowance
	£m	£m	£m	£m	£m	£m	£m	£m	£m
CN - Midlands	444	(18)	426	33	24	72	554	47	**600**
CN - East Midlands	445	(14)	431	31	9	77	547	38	**585**
Unitied Utilities	439	(21)	418	27	-	69	513	46	**559**
CE - NEDL	263	(18)	245	15	-	50	310	51	**361**
CE - YEDL	346	(19)	328	21	4	61	413	30	**443**
WPD-South West	269	(20)	249	14	-	55	317	43	**360**
WPD-South Wales	171	(13)	158	9	6	47	219	30	**249**
EDF - LPN	398	(20)	378	55	-	61	494	63	**557**
EDF - SPN	433	(20)	413	33	21	61	528	60	**587**
EDF - EPN	609	(25)	584	66	23	96	768	36	**804**
SP Distribution	335	(14)	321	27	-	65	414	14	**428**
SP Manweb	363	(13)	350	41	-	54	445	46	**491**
SSE - Hydro	189	(12)	178	14	-	44	236	11	**247**
SSE - Southern	511	(21)	490	26	25	81	621	87	**709**
Total	**5,216**	**(247)**	**4,969**	**408**	**112**	**892**	**6,379**	**601**	**6,980**

Note:
1. This table shows the derivation of the capital expenditure allowances - the columns do not constitute separate allowances

Table A11: Detailed RAV calculation for actual (April 1998 to March 2004) and projected (2004/05) capex

RAV roll forward to 31 March 2005

£m '02/03	CN - Midlands	CN - East Midlands	United Utilities	CE - NEDL	CE - YEDL	WPD - South West	WPD - South Wales	EDF - LPN	EDF - SPN	EDF - EPN	SP Distribution	SP Manweb	SSE - Hydro	SSE - Southern	Total
RAV as at 1 April 1998	**933**	**1,000**	**777**	**543**	**861**	**670**	**522**	**896**	**527**	**1,074**	**1,479**	**650**	**749**	**1,414**	**12,096**
DNO additions excluding adjustments	530	470	587	333	458	377	320	503	427	742	529	465	291	622	6,652
Adjustments															
Corporate costs	(3)	(8)	-	-	-	(3)	(3)	(1)	-	-	(2)	(1)	(1)	(1)	(23)
Inter/Intra Group margins	-	-	(1)	(8)	(1)	(0)	(0)	(24)	(5)	1	(15)	(21)	(2)	(3)	(77)
Non-operational depreciation	(16)	-	-	(6)	(6)	(6)	(3)	(11)	(9)	(11)	(14)	(14)	(5)	(9)	(111)
Overstay penalties	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	(0)
Pension accruals to cash adjustment	(1)	-	1	(5)	(3)	(12)	(1)	(6)	(4)	(6)	(7)	(6)	(2)	(3)	(56)
Other capitalisation adjustments	(4)	(1)	(7)	-	-	(1)	(0)	-	-	(6)	-	-	(4)	(3)	(27)
Fault expenditure	-	-	(15)	-	(56)	-	-	-	(46)	-	(4)	(2)	-	-	(124)
Indirect costs capitalised	1	(4)	11	16	6	(9)	-	(8)	(1)	(27)	(40)	(23)	-	(5)	(83)
Meter recertification expenditure	(10)	20	(1)	1	(7)	11	8	-	-	-	(7)	(3)	(3)	(5)	3
	(32)	7	(12)	(1)	(68)	(21)	0	(50)	(65)	(49)	(89)	(71)	(16)	(30)	(497)
Net additions	**498**	**477**	**575**	**331**	**390**	**356**	**320**	**453**	**362**	**693**	**439**	**394**	**276**	**592**	**6,155**
Depreciation	**(456)**	**(498)**	**(454)**	**(278)**	**(442)**	**(314)**	**(255)**	**(433)**	**(298)**	**(652)**	**(605)**	**(317)**	**(275)**	**(635)**	**(5,912)**
RAV as at 31 March 2004	**976**	**978**	**898**	**596**	**809**	**712**	**587**	**916**	**591**	**1,115**	**1,314**	**727**	**749**	**1,371**	**12,339**
DNO additions (04/05 f'cast) excluding adjustments	97	81	116	59	102	71	44	94	114	153	80	113	38	111	1,272
Adjustments															
Corporate costs	(1)	(2)	-	-	-	(1)	(0)	(0)	-	-	(0)	(0)	(0)	(0)	(5)
Inter/Intra Group margins	-	-	(0)	(1)	(1)	(0)	(0)	-	-	-	(5)	(7)	(0)	(1)	(14)
Non-operational depreciation	(4)	-	-	(0)	(2)	(1)	(1)	(1)	-	(1)	(4)	(5)	(1)	(1)	(20)
Overstay penalties	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	(0)
Pension accruals to cash adjustment	-	-	-	-	-	(5)	(2)	-	-	-	-	-	-	-	(6)
Other capitalisation adjustments	(0)	1	(1)	-	-	(1)	(0)	-	-	-	-	-	-	-	(2)
Fault expenditure	-	-	(3)	-	(9)	-	-	-	(5)	-	(1)	(0)	-	-	(18)
Indirect costs capitalised	(1)	(4)	(5)	1	1	(8)	-	(1)	(2)	(5)	(20)	(18)	-	-	(61)
Meter recertification expenditure	(1)	3	-	0	-	3	2	-	-	-	(1)	(1)	-	-	6
	(7)	(2)	(10)	0	(10)	(13)	(2)	(2)	(7)	(6)	(31)	(30)	(1)	(2)	(123)
Net additions	**90**	**79**	**106**	**59**	**91**	**58**	**42**	**91**	**106**	**147**	**49**	**83**	**37**	**109**	**1,149**
Depreciation	**(85)**	**(91)**	**(63)**	**(43)**	**(80)**	**(59)**	**(44)**	**(80)**	**(41)**	**(96)**	**(108)**	**(60)**	**(50)**	**(116)**	**(1,015)**
RAV as at 31 March 2005	**981**	**966**	**941**	**612**	**820**	**711**	**586**	**928**	**656**	**1,166**	**1,255**	**750**	**737**	**1,364**	**12,473**
less : Meters DRC	(16)	(18)	(21)	(15)	(16)	(15)	(13)	(19)	(15)	(27)	(22)	(15)	(9)	(14)	(234)
RAV as at 1 April 2005	**965**	**948**	**920**	**597**	**805**	**696**	**574**	**909**	**641**	**1,138**	**1,233**	**735**	**728**	**1,350**	**12,239**

Table A12: Pension allowances

DNO	Normal Cost 2005/06 £m	Normal Cost 2006/07 £m	Normal Cost 2007/08 £m	Normal Cost 2008/09 £m	Normal Cost 2009/10 £m	Deficit Recovery Per annum 2005/06 £m	Total Allowance 2005/06 £m	Total Allowance 2006/07 £m	Total Allowance 2007/08 £m	Total Allowance 2008/09 £m	Total Allowance 2009/10 £m
CN – Midlands	6.4	6.4	6.4	6.4	6.3	9.9	16.2	16.2	16.2	16.2	16.2
CN – East Midlands	5.0	5.1	5.1	5.1	5.1	8.0	13.0	13.1	13.1	13.1	13.1
United Utilities	7.4	7.5	7.5	7.5	7.5	8.6	16.0	16.0	16.0	16.0	16.0
CE – NEDL	5.7	5.9	6.1	6.2	6.4	11.6	17.4	17.5	17.7	17.9	18.0
CE – YEDL	6.0	6.2	6.3	6.5	6.7	4.1	10.1	10.3	10.5	10.7	10.8
WPD – South West	6.5	6.7	6.9	7.1	7.3	7.9	14.4	14.6	14.8	15.0	15.2
WPD – South Wales	4.2	4.1	4.4	4.6	4.7	5.8	10.0	9.9	10.2	10.4	10.5
EDF – LPN	6.6	6.8	6.9	7.1	7.2	15.0	21.7	21.8	21.9	22.1	22.2
EDF – SPN	6.5	6.6	6.7	6.8	7.0	13.9	20.4	20.5	20.6	20.7	20.9
EDF – EPN	8.3	8.5	8.7	8.9	9.1	3.8	12.1	12.3	12.5	12.7	12.9
SP Distribution	4.8	4.8	4.8	4.8	4.8	n/a	4.8	4.8	4.8	4.8	4.8
SP Manweb	4.5	4.5	4.5	4.5	4.5	11.2	15.7	15.7	15.7	15.7	15.7
SSE – Hydro	3.9	3.9	3.9	3.9	3.9	n/a	3.9	3.9	3.9	3.9	3.9
SSE – Southern	7.3	7.3	7.3	7.4	7.4	22.9	30.2	30.2	30.2	30.3	30.3
Total	**83.0**	**84.1**	**85.5**	**86.6**	**87.8**	**122.7**	**205.8**	**206.8**	**208.2**	**209.3**	**210.6**

Note:

The price control calculations assume that 57.7% of the above allowance will be capitalised and the remainder expensed as opex.

Table A13(a): Allowance for pension deficit funding

DNO (2002/03 prices)	**Pension Deficit**	**Distribution Deficit**	**Disallowed ERDCs**	**Allowed Deficit**	**Deficit Funding per annum**
Notes		(1)	(2)		(3)
	£m	£m	£m	£m	£m
CN – Midlands	137.4	109.9	22.1	87.8	9.9
CN – East Midlands	108.1	86.5	15.2	71.3	8.0
United Utilities	115.9	92.7	16.5	76.2	8.6
CE – NEDL	146.5	117.2	13.6	103.6	11.6
CE – YEDL	38.9	38.9	2.0	36.9	4.1
WPD – South West	115.6	92.5	22.0	70.4	7.9
WPD – South Wales	74.7	59.8	8.3	51.5	5.8
EDF – LPN	177.1	141.7	8.0	133.6	15.0
EDF – SPN	150.1	120.1	18.1	101.9	13.9
EDF – EPN	34.1	34.1	0.0	34.1	3.8
SP Distribution	n/a	n/a	n/a	n/a	n/a
SP Manweb	126.7	101.4	1.7	99.7	11.2
SSE – Hydro	n/a	n/a	n/a	n/a	n/a
SSE – Southern	268.0	214.4	10.5	203.9	22.9
Total	**1,493.1**	**1,209.1**	**138.0**	**1,071.1**	**122.7**

Notes (1) 80% of total except EPN and YEDL (both 100%)
(2) Adjusted for historic scheme returns
(3) Allowed deficit amortised over 13 years (10 years SPN)

Table A13(b): Movement in allowance for pension deficit funding since September Update (£m, 2002/03 prices)

Average Annual Pension Allowance	September Allowances	Updated Deficits and Normal Contributions	Revised Contribution Start Date	Revised Amortisation Period	November Allowances
	£m	£m	£m	£m	£m
CN - Midlands	15.6	-0.3	0.9	0.0	16.2
CN - East Midlands	13.6	-1.3	0.8	0.0	13.1
United Utilities	13.8	1.4	0.8	0.0	16.0
CE - NEDL	17.0	-0.3	1.0	0.0	17.7
CE - YEDL	8.9	1.3	0.3	0.0	10.5
WPD - South West	14.6	-0.6	0.8	0.0	14.8
WPD - South Wales	10.3	-0.6	0.5	0.0	10.2
EDF - LPN	20.0	0.7	1.2	0.0	21.9
EDF - SPN	14.5	2.6	1.1	2.4	20.6
EDF - EPN	10.3	1.9	0.3	0.0	12.5
SP Distribution	4.6	0.2	0.0	0.0	4.8
SP Manweb	15.2	-0.4	0.9	0.0	15.7
SSE - Hydro	3.3	0.6	0.0	0.0	3.9
SSE - Southern	28.0	0.4	1.8	0.0	30.2
Totals	189.7	5.6	10.4	2.4	208.2

Note 1 Revised contribution start date because contributions are not expected to start until April 2005, so no deduction required for contributions in 2004/05

Note 2 Amortisation period for SPN revised to 10 years to reflect significantly shorter average remaining service life compared to other DNOs

Table A14: Summary of the calculation of pension deficit funding (£m, 2002/03 prices)

DNO (2002/03 prices)	**Pension Deficit**	**Distribution Deficit**	**Disallowed ERDCs**	**Allowed Deficit**	**Deficit Funding per annum**
Notes		(1)	(2)		(3)
	£m	£m	£m	£m	£m
CN – Midlands	137.4	109.9	22.1	87.8	9.9
CN – East Midlands	108.1	86.5	15.2	71.3	8.0
United Utilities	115.9	92.7	16.5	76.2	8.6
CE – NEDL	146.5	117.2	13.6	103.6	11.6
CE – YEDL	38.9	38.9	2.0	36.9	4.1
WPD – South West	115.6	92.5	22.0	70.4	7.9
WPD – South Wales	74.7	59.8	8.3	51.5	5.8
EDF – LPN	177.1	141.7	8.0	133.6	15.0
EDF – SPN	150.1	120.1	18.1	101.9	13.9
EDF – EPN	34.1	34.1	0.0	34.1	3.8
SP Distribution	n/a	n/a	n/a	n/a	n/a
SP Manweb	126.7	101.4	1.7	99.7	11.2
SSE – Hydro	n/a	n/a	n/a	n/a	n/a
SSE – Southern	268.0	214.4	10.5	203.9	22.9
Total	**1,493.1**	**1,209.1**	**138.0**	**1,071.1**	**122.7**

Notes
(1) 80% of total except EPN and YEDL (both 100%)
(2) Adjusted for historic scheme returns
(3) Allowed deficit amortised over 13 years (10 years SPN)

Table A15: Calculation of CSV

DNO	Network Length ('000 km) A	Customer Numbers (m) B	Units Distributed (GWh) C	CSV
CN - Midlands	60.3	2.3	27.3	21.9
CN - East Midlands	68.9	2.4	28.9	24.0
United Utilities	59.0	2.3	25.4	21.2
CE - NEDL	39.9	1.5	17.0	14.2
CE - YEDL	51.1	2.2	24.3	19.2
WPD - South West	48.1	1.4	15.4	15.1
WPD - South Wales	33.5	1.1	12.6	11.1
EDF - LPN	30.7	2.1	27.0	15.2
EDF - SPN	49.5	2.1	21.2	18.3
EDF - EPN	92.1	3.4	36.3	32.0
SP Distribution	67.3	1.9	22.3	21.0
SP Manweb	45.5	1.4	16.8	15.0
SSE - Hydro	48.3	0.7	8.5	10.8
SSE - Southern	75.0	2.7	32.8	26.6