Electricity Distribution Price Control Review

Update paper

September 2004

Summary

In June 2004, Ofgem published for consultation its Initial Proposals for the Electricity Distribution Price Control Review. This paper provides an update on those proposals, reflecting updated information and comments received, and drawing on extensive discussions with the distribution companies and other interested parties. Comments are invited by 25 October 2004, to allow Final Proposals to be published on 29 November.

Context of the price control review

The overall objective of the price review is to protect the interests of consumers. This includes both the prices they pay and the service that they receive. Ofgem must also have regard to its other statutory duties, including its duty to ensure that licensees can finance their activities and duties relating to the environment, and it must take into account the effects of government energy policy.

The present review takes place against the background of rising retail prices and increasing concern about security of supply and environmental issues. The proposals acknowledge and respond to these issues. Operational performance and effective management are vital in improving efficiency, delivering secure and reliable supplies and responding to increases in distribution-connected generation. Significant increases in investment will also be necessary. The review must similarly reflect increases in costs that are outside the companies' control.

Key issues

Earlier consultation papers highlighted three key themes:

- Incentives for investment and efficiency;
- Quality of service; and
- Responding to the challenge of growth in renewable energy.

In these areas, Ofgem considers that the fundamental approach established in Initial Proposals remains generally valid and represents a major contribution to protecting the interests of consumers. However, it is appropriate to update allowances, targets and revenues based on data that has become available since June. In addition, many detailed arguments have been put forward by the distribution companies in respect of

the Initial Proposals on capital expenditure, operating costs and quality targets, and also on the financial model. As a result, a number of changes have been made on points of detail, whilst the assumption of ongoing operating cost efficiency has been scaled back from 2 per cent to 1.5 per cent per annum. Capital expenditure allowances have been increased slightly and are now, in aggregate, 46 per cent above the comparable level of investment in the current period.

The aggregate effect of such changes reflected in the present paper increases allowed revenues by approximately 2 per cent, and brings the cost allowances to levels that, in the majority of cases for opex and capex, are broadly comparable with the companies' own forecasts.

The present paper also proposes significant changes in two other areas, which together increase allowed revenues by a further 5 per cent.

- First, on pensions, the Initial Proposals left certain aspects of the treatment of the current deficits for later consideration. Whilst a range of possible treatments could be used, it is proposed that a relatively high proportion of the deficit will pass through to consumers. This reduction of risk for the companies will be considered in assessing the cost of capital. The approach also provides some reassurance for pension fund trustees.

- Secondly, on tax, the Initial Proposals assumed that companies could make significant changes to improve their tax position. The present approach uses a more neutral assumption but also provides for a partial clawback so that consumers will share in the benefits if companies improve their tax position.

A firm proposal on the calculation of the Regulatory Asset Value (RAV) is established in this paper. It reflects, as far as possible, the basis on which the present price control was set. The proposal does not have a material effect on the industry-wide RAV when compared with the estimate provided in Initial Proposals. It does, however, have a material impact on a number of individual companies.

In a number of cases, distribution charges will need to rise. It appears better to limit the adjustment in 2005 and thereafter to allow prices to rise in line with inflation, rather than to have a larger initial price increase followed by an annual reduction in real terms. This implies setting the X factor to zero rather than one as initially proposed. This reduces the initial price change by 2 percentage points.

Impact on distribution charges

The impact on price changes (the so-called P0s), compared to the Initial Proposals, is set out below.

Updated proposals for P0

DNOs	June Initial proposals	September Update	Difference
	%	%	%
CN - Midlands	-6%	-5%	2%
CN - East Midlands	-11%	-8%	3%
Unitied Utilities	-2%	6%	7%
CE - NEDL	-11%	-3%	8%
CE - YEDL	-15%	-13%	2%
WPD-South West	0%	2%	2%
WPD-South Wales	2%	7%	6%
EDF - LPN	-2%	-4%	-2%
EDF - SPN	-4%	3%	7%
EDF - EPN	-5%	-2%	2%
SP Distribution	8%	11%	2%
SP Manweb	4%	-6%	-10%
SSE - Hydro	0%	3%	3%
SSE - Southern	6%	9%	3%
Total	-2%	0%	2%

In some cases, particularly SP Manweb, the apparent change in P0 relates largely to a change in the forecast of 2004/05 revenue, rather than a change in allowed revenue for 2005/06 or subsequent years. The updated proposals for revenue allowances, in comparison with the Initial Proposals, are set out in the following table.

Updated proposals for average revenue allowance 2005-2010

DNOs	June Initial proposals	September Update	Increase
	£m	£m	£m
CN - Midlands	227	241	15
CN - East Midlands	229	245	16
Unitied Utilities	201	220	19
CE - NEDL	140	159	18
CE - YEDL	187	197	11
WPD-South West	170	180	10
WPD-South Wales	136	148	12
EDF - LPN	224	227	4
EDF - SPN	150	166	16
EDF - EPN	279	289	11
SP Distribution	284	292	8
SP Manweb	169	176	7
SSE - Hydro	157	169	12
SSE - Southern	328	341	13
Total	2880	3050	170

Next steps

The principal decision for Final Proposals in November relates to the cost of capital. This will be considered by the Authority in the context of the overall balance of risk and reward provided by the entirety of the proposals. There are a small number of company-specific or relatively lower magnitude issues that remain outstanding, together with the mechanics of the new incentives and risk-mitigation arrangements. In general, unless otherwise noted, the policy decisions set out in this paper are unlikely to change unless compelling new evidence or arguments are produced.

Responses to this document are invited by 25 October 2004. Ofgem intends to publish Final Proposals on 29 November.

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1. Introduction

1.1. The existing price controls on the electricity Distribution Network Operators (DNOs) are due to be reset with effect from 1 April 2005. The work underpinning the establishment of new controls began early in 2003; so far, Ofgem has published four consultations and one update document.[1]

1.2. Ofgem published Initial Proposals in June 2004. Since then:

- Ofgem has provided DNOs with drafts of the reports commissioned from consultants PB Power (on capital expenditure) and Ernst & Young (on aspects of operating practices) and with copies of the financial model used to set Initial Proposals; and
- Ofgem has held a number of bilateral meetings with each DNO and has met with other consultation respondents to understand their views.

1.3. The Ofgem-DNO working groups have also met on a number of occasions to discuss key issues. A new working group has been established to discuss issues regarding the drafting of legal text for the licence conditions through which the price control is to be implemented.

Purpose and structure of this document

1.4. This update document focuses on issues where there have been significant developments subsequent to the Initial Proposals or where additional feedback is required prior to setting out the Final Proposals.

1.5. This document is structured as follows:

- **metering (Chapter 2)** – outlines proposed price caps for provision of basic meters and revenue caps for meter operation services;

[1] Ofgem document references 68/03 (July 2003), 124/03 (October 2003), 171/03 (December 2003), 62/04 (March 2004) and 145/04 (June 2004)

- **quality of service and other outputs (Chapter 3)** – updates quality of service targets and cost allowances, arrangements for exceptional events and targets for the losses incentive;

- **assessing costs (Chapter 4)** – provides a detailed discussion of the analysis of operating costs and capital expenditure, along with the proposed incentives for cost efficiency;

- **financial issues (Chapter 5)** – updates the allowances for pensions and tax, and calculation of the Regulatory Asset Value (RAV), and summarises other changes that impact on the price control calculations; and

- **detailed cost allowance tables and price control calculations (Appendix)**

1.6. Ofgem has also published two related documents:

1. a summary of responses to the Initial Proposals document[2], which also contains Ofgem's view on issues raised regarding topics that do not come under the scope of this update; and

2. a draft Impact Assessment (IA) for the price control review[3].

Responding to this document

1.7. Ofgem would like to hear the views of all those with an interest in the development of revised price controls for the DNOs, including consumers and their representatives, investors and city analysts, distributed generators, environmental groups, suppliers, other network operators and the DNOs themselves.

1.8. Responses are particularly invited on those issues outlined at the end of each Chapter.

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[2] Electricity Distribution Price Control Review, Summary of responses to June 2004 Initial Proposals, September 2004

[3] Electricity Distribution Price Control Review, Draft Impact Assessment, September 2004

1.9. Responses to this document and any of the separate Appendices and documents that Ofgem has published should be received by 25 October 2004. They should be sent to:

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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

Next steps

1.10. The timetable remains as set out in the June Initial Proposals document.

1.11. The Final Proposals will be published on 29 November and will set out Ofgem's views on the cost of capital and the resultant price controls. Ofgem does not intend to re-open policy positions that are set out in this paper unless there is compelling new evidence or analysis. However, the Final Proposals paper will include comprehensive coverage of all the issues covered in the price review and will supersede all previous documents, including this one.

2. Metering

2.1. As noted in the Initial Proposals, Ofgem's objective in reviewing the price control treatment of metering is to protect the interests of consumers through securing effective competition in the provision of metering services. It is therefore very important that price controls do not distort competition. This has led Ofgem to propose separating metering price controls from distribution price controls from 1 April 2005, and has also influenced both the structure and level of control proposed. Ofgem has sought to balance the promotion of competition with providing a safeguard for consumers during the development of competition.

2.2. This Chapter sets out how Ofgem's proposals have changed in the light of responses to the June consultation, and further analysis of the issues raised. A particular focus of concern in some responses was the interests of consumers using pre-payment meters (PPMs). In some cases respondents argued that Ofgem was promoting competition at the expense of these consumers. Some of the major costs in providing services to PPM consumers relate to the costs associated with the provision of infrastructure to support PPM consumers. Ofgem considers that by facilitating effective choice in relation to PPM assets, competition will mean that overall efficiency gains are likely to be achieved which mean the overall cost to suppliers of PPM consumers is expected to fall.

2.3. The likely response of DNOs who are facing an increase in the capped PPM price is unclear. If these DNOs choose to price up to the cap, they will be likely to accelerate the shift to competitive procurement by suppliers, and it is not clear this will be in their commercial interests. In addition, suppliers may or may not in the short term pass through changes in meter costs to their consumers. Ofgem is satisfied that the innovation and efficiency gains that are facilitated by pricing PPMs at cost will lead to benefits for all PPM consumers in the long term.

2.4. The other major theme of consultation responses was concern that DNOs might be exposed to unavoidable losses as suppliers move towards national standardisation of PPM technology. Given potential back-office savings for suppliers from such standardisation, this seems likely and may lead to accelerated meter replacement. Ofgem understands that a number of DNOs have introduced a charge on suppliers should the supplier choose to remove that meter before the end of its expected life. These charges are frequently referred to as "Termination Charges".

2.5. Ofgem has recognised the case for giving DNOs some protection against this risk, which is a consequence of regulatory change rather than the companies' own actions. It is proposed to achieve this protection through an adjustment to the price control, rather than through permitting termination charges.

2.6. Taken together, Ofgem considers that the price control will minimise regulatory barriers faced by DNOs and other players seeking to participate in metering markets on fair terms.

Meter Asset Provision (MAP)

Standardised MAP charge

2.7. The June Initial Proposals set out a range of price caps for basic MAP. A number of respondents raised concerns with the diversity of ranges between the different DNOs' price caps for what is a reasonably similar activity. As a result of these concerns Ofgem undertook a further investigation into the efficient cost of a meter. It became apparent to Ofgem that the similar nature of MAP across the DNOs meant that the differences in charges between DNOs were unwarranted. In light of this analysis Ofgem now proposes to implement four separate price caps. These price caps are set out in the table below:

Annual Price Caps for MAP in 2002/03 prices	
Meter Type	Annual Charge (£)
Single phase Single Rate	1.11
Single Rate Token Prepayment Meter	8.46
Single Rate Key Prepayment Meter	8.91
Single Rate Smartcard Prepayment Meter	11.58

2.8. These price caps represent the maximum per year that a DNO can charge for the provision of a meter of that type. All other meter types will be covered by a non-discrimination provision to prevent excess profits being earned by the DNOs. In relation to PPMs, a DNO will only be obliged to provide the type of meter it was providing at 1 June 2003.

2.9. The separate price caps for the different PPM technologies reflect the differences in underlying cost and expected effective life of each type of meter. It was also decided to separate out the different types of meter to provide certainty for both distributors and electricity suppliers in relation to the charges levied, should it become commercially justified to change from one technology to another.

Change to Asset Recovery

2.10. In deriving the metering price caps for the June Initial Proposals document, in order to calculate the required return, Ofgem applied an assumed regulatory rate of return to the depreciated replacement value for metering assets. A number of respondents raised concerns with this approach. As a result of which Ofgem has modified the basis of the calculation of price caps.

2.11. The reason for this is that under the approach set out in the June Initial Proposals document the rate of return for the meter was to be calculated using the depreciated replacement cost of the metering assets as reported by DNOs. As a result the return for MAP was heavily influenced by the average age of the DNO's metering stock in 2002/03. A DNO with a relatively new meter stock would have a higher depreciated asset value than a DNO with a relatively old meter stock. However, the fixed certification life of meter assets means the older meter asset will be replaced sooner. Therefore, the depreciated replacement value of meters, even when based on 2002/03 purchase prices, will change over time.

2.12. Ofgem is now proposing a different approach to the recovery of the asset value and the calculation of the regulatory return. This approach will be based on the purchase value of a new meter asset depreciated on a straight line basis over its expected useful life. The return on assets will then be calculated by reference to the depreciated value for each year of the expected life of the asset. The depreciation and the regulatory return will be added together for each year. The average will then be taken of all the years and that will be the asset cost recovery for the purposes of the price control.

2.13. Below is an example based on a £10 asset with a five year life and a cost of capital of 10 percent. These numbers are not an accurate representation of the actual numbers in the price control but have been selected for illustrative purposes.

Year	**1**	**2**	**3**	**4**	**5**
Opening Asset Value	£10.00	£8.00	£6.00	£4.00	£2.00
Depreciation	£2.00	£2.00	£2.00	£2.00	£2.00
Cost of Capital	£1.00	£0.80	£0.60	£0.40	£0.20
Payment	£3.00	£2.80	£2.60	£2.40	£2.20
Average of the Payments/ asset cost recovery	**£2.60**				

Changes to allocation of Operating Costs and Overheads

2.14. In the June proposals operating expenditure (opex) was allocated on a weighted average value basis to each meter asset. This approach allocated more overheads and opex to a PPM than a domestic credit meter. Given the nature of opex and overheads in MAP there is no reason that PPM should bear a greater proportion.

2.15. Therefore, as a result of responses to the June proposals, Ofgem intends to allocate opex and overheads on a flat rate calculated by dividing the total opex and overheads by the number of meters.

Effect of Changes

2.16. An approximation of the effect of the changes to asset cost recovery and the allocation of OPEX and overheads can be seen in the table below.

Effect of changes to the calculation of MAP			
Meter	Initial Proposals (£/year)	September Update (£/year)	Change
Domestic Credit	0.87	1.11	28%
Token Prepayment	8.24	8.46	3%
Key Prepayment	8.67	8.91	3%
Smart Card Prepayment	11.23	11.58	3%

Prepayment Meters

2.17. At present domestic credit meters are frequently removed when visited by a metering engineer as the cost of the labour for the visit is significantly higher than the cost of the meter. Ofgem does not envisage that competition will result in a significant change in the treatment of existing domestic credit meters.

2.18. Where it is economically efficient for an industrial and commercial (I&C) meter to remain in place a DNO and the supplier could arrive at a price that the supplier would be happy to continue to use the DNOs meter rather than replace it with a meter provided by a competitive MAP.

2.19. However, there is uncertainty surrounding the effect competition will have on the expected life of a PPM. In Great Britain there are three different types of technology used for PPM (token, key and smartcard). Each has an associated infrastructure. Owing to the infrastructure costs, if a supplier decides on a particular PPM technology then it is possible that the installed PPM will be replaced upon a visit by the metering engineer even if the DNO lowers the price of the meter to encourage its continued use.

2.20. Since these meters have been provided as a result of regulatory obligation it would be inappropriate for all the burden of this risk to fall solely on the DNOs. Therefore, the price control for providing a PPM will contain a formula that will adjust the price cap for the expected life of the asset. Ofgem will set the expected life of the PPM. In order to have the expected life of the asset reduced (i.e. to be allowed to charge more for providing a PPM) the DNO will have to satisfy Ofgem as to the extent of any reduction in the expected life of the asset as a result of premature replacement.

2.21. There will be a cap placed on the extent of the possible reduction in the asset life of 30 per cent. Ofgem considers that this protects consumers from excessive price rises over the period of the price control. It also reflects Ofgem's intention to remove the obligation to provide new meters from DNOs from 1 April 2007.

Prohibition on Termination Charges

2.22. Ofgem is concerned that the dominant supplier of metering services levying "Termination Charges" could have a negative affect on the development of competition in metering. Therefore, Ofgem will not be including an allowance for "Termination Charges" in the price control. As Ofgem is allowing DNOs to recover the costs associated with the early removal of PPMs, it is not necessary to allow them to remove this risk by levying termination charges.

Meter Operation (MOp)

Methodology

2.23. In the June Initial Proposals document Ofgem did not publish a revenue cap for MOp. This was as a result of the large variation in the costs that the DNOs were providing to Ofgem for MOp. As a result of the inconsistency Ofgem decided to supplement the information it had gathered by undertaking an analysis of the metering contracts of those DNOs who had contracted the provision of metering services from third parties. Moreover, using market-based data provides a general assurance that costs are broadly efficient.

2.24. This approach provided certainty that all DNO metering costs had been captured in separating metering from distribution as third party meter service providers would not subsidise the distribution business.

2.25. Ofgem then amalgamated some of these costs into a list of activities so they could be compared across the different DNOs. The proportion that these activities represented of the total activities undertaken by DNOs was calculated. Previously the DNOs had provided the total number of activities they performed in a year. Using the average proportion of activities and the 60th percentile of the costs in the contracts investigated as the price per activity a revenue control was calculated. The 60th percentile was selected as it meant that the DNOs fully recovered their costs. The revenue control and the activities underpinning it have recently been shown to the DNOs to facilitate their understanding of how it was derived.

2.26. A 1.5 per cent mark-up has been added to the costs to create an appropriate level of return for the DNOs in relation to MOp.

Revenue Cap

2.27. Below is a table outlining the initial revenue controls shown to the DNOs.

Base Annual Revenue Cap for MOp in 2002/03 prices	
DNO	Revenue Control (£m per annum)
CN – Midlands	8.3
CN- East Midlands	9.4
United Utilities	4.9
CE – NEDL	8.1
CE – YEDL	7.9
WPD – South West	6.5
WPD – South Wales	4.5
EDF – LPN	7.1
EDF – SPN	8.6
EDF – EPN	11.7
SP Distribution	4.5
SP Manweb	3.4
SSE – Hydro	2.8
SSE – Southern	9.7

2.28. Ofgem will consider changes to these costs prior to the commencement of the revenue control where the DNOs can demonstrate to Ofgem that their activities occur in different proportions than assumed in deriving these revenue controls.

It is also anticipated that the revenue control may change for some DNOs who are able to prove their cost per activity differ from those proposed by Ofgem.

2.29. Ofgem is not proposing to publish the break down of activities and the DNOs' responses as these are commercially sensitive in nature.

Inclusions and Exclusions

2.30. It should be noted that the metering price controls do not cover activities such as revenue protection, idle service inspections, collecting and executing warrants of entry, bulk re-programmes performed by the meter reader, activity associated with the installation or changing of isolators, or half-hourly metering. Ofgem is of the view that these services are not supplied by the metering business as a result of a licence obligation in relation to metering and, therefore, should not form part of the metering price control. However, these items will be treated as excluded services so that those metering businesses who currently perform them will continue to be able to do so.

Derivation of the Revenue Driver

2.31. In the Initial Proposals, Ofgem indicated that the MOp revenue control driver will be the number of meters. Ofgem is concerned that this outcome may have been the result of the poor quality of cost data that Ofgem had at the time. Therefore, Ofgem will undertake analysis to determine the most appropriate driver once it has finalised the MOp cost.

2.32. Ofgem will be using ordinary least squares linear regressions in order to derive the driver for the revenue control. Ofgem will look at a number of different possible variables and combinations of variables and select that which provides the strongest explanatory power. The variables that Ofgem is proposing to run regressions on are:

- The number of meters;
- The volume of activities/visits;
- The volume of single phase activities and the volume of polyphase activities; and

- A dummy variable for the type of PPM technology.

Ofgem invites views from interested parties, with supporting reasons, on other variables they consider Ofgem should include in its regressions.

Basic Services

2.33. In the June Initial Proposals document Ofgem proposed that basic meter services should be defined as the functionality that was in place as of 1 April 2003. A number of DNOs have indicated that they had not separated MAP and MOp at that stage so would have difficulty in complying with an obligation that relates to the functionality as at 1 April 2003. Ofgem regards the past failure as regrettable, but in consequence proposes to amend the reference date to 1 June 2003: that is, the first day of the month after the commencement of the metering arrangements introduced by the Review of Electricity Metering Arrangements.

2.34. Ofgem is seeking feedback from the DNOs and other interested parties as to whether this arrangement will work with the MOp revenue control. Ofgem's concern arises from the nature of appointments made under the industry agreements as at 1 June 2003.

2.35. The revenue control assumes a mix of appointment times between normal, short notice and 2 hour banded. If the contracts as of 1 June 2003 are not sufficiently robust to maintain that mix then an approach where Ofgem issues a determination of what is a basic MOp service will have to be undertaken. This determination will exclude anything other than normal appointments. DNOs and suppliers will then be free to commercially negotiate agreements for the other types of appointment.

One Way Door

2.36. In the June Initial Proposals document Ofgem indicated that it would be proposing to modify the licence obligation on DNOs so that it does not apply to suppliers in relation to meter points at which they have decided to take services from metering services providers other than the DNO. For the avoidance of doubt, the DNO will still be obliged to provide metering services to a new supplier (after the customer switches supplier), even with regard to a meter point where the old supplier had de-appointed the DNO.

Views invited

2.37. Views are particularly invited on variables that should be included in the analysis of the revenue driver for MOp and the ability of the industry agreements in place at 1 June 2003 to maintain the mix of appointment times.

3. Quality of service and other outputs

Introduction

3.1. The Initial Proposals set out a framework for quality of service regulation for the period 2005-10, based on incremental improvements on current levels of service with associated cost allowances.

3.2. This Chapter sets out updated proposals for interruptions targets, for the arrangements for assessing the accuracy of performance data and for arrangements to apply in the case of exceptional events such as severe weather. It also includes a brief update on losses targets.

Interruptions targets

3.3. Since the publication of the June paper, Ofgem has undertaken further work to update the interruption targets. This has included:

- updating the disaggregation and benchmarking analysis – some DNOs had incorrectly included exceptional events occurring during 2003/4 in their disaggregated data submissions;

- updating the forecast for planned interruptions – the DNOs have submitted further information on how they calculated their planned interruption forecasts and provided revised forecasts to take into account Ofgem's Initial Proposals. Ofgem has considered this information in setting revised forecasts for planned customer interruptions (CI) and planned customer minutes lost (CML). The forecasts for planned CML have been calculated by multiplying the forecast for planned CI by the better of the DNO's own and the industry average restoration times (planned CML per CI) for 2001/2 to 2003/4;

- incorporating the latest CI and CML interruption data for 2001/2 to 2003/04 (with adjustments for changes in the treatment of exceptional events);

- incorporating revised data submissions for EHV and 132 kV for some of the DNOs to reflect rebasing of their historic performance data; and

- correcting the calculation of average CML/CI at 132 kV for those DNOs that had zero CI in any year.

3.4. The targets have also been updated to reflect further discussions with the DNOs. SP Manweb is the frontier performer on CI, being the only DNO to outperform the upper quartile benchmark rolled forwards to 2020. SP Manweb's target has been adjusted to the upper quartile benchmark to allow it scope for outperformance in the future.

3.5. The targets for CML in Initial Proposals used benchmarks for restoration based on average performance across companies at low voltage, upper quartile performance at high voltage and an average of the companies' own performance at EHV and 132 kV.

3.6. In general, benchmark industry restoration times at high voltage are based on a mixture of restoring consumers' supplies through switching in alternative feeding arrangements or repairing faults. The urban interconnected network in SP Manweb differs significantly from those in other DNOs as it is unit-protected and the majority of faults that cause consumers to be interrupted will require repairs to be made in order to restore consumers. For this part of SP Manweb's network it is therefore inappropriate to use upper quartile restoration times as a benchmark. Ofgem has recalculated SP Manweb's CML target using average restoration times for its underground circuits and upper quartile restoration times for its other circuits.

3.7. A correction has also been applied for DNOs that are currently outperforming the 2020 benchmarks for CIs. Their revised CML targets have been calculated by applying the benchmark CML/CI for each voltage and each disaggregation band to the DNOs' actual CIs. The targets in the Initial Proposals were based on the same total CIs, but the voltage split was based on the CI benchmarks and the calculation was carried out for high voltage as a whole rather than by band. This correction results in an increase in the CML targets of approximately 1 for United Utilities and for SP Manweb. It has a minor impact on SSE-Hydro, Ce-NEDL and SP Distribution.

3.8. A number of companies have raised concerns with the approach to setting CML targets. They argue that:

- Ofgem's benchmark calculations effectively assume that all DNOs have similar networks and that the proposed upper quartile targets are similarly attainable; and

- it is inappropriate to apply an upper quartile benchmark for restoration times (CML/CI) to a CI benchmark based on average performance. They have suggested that there is a relationship between CI and restoration times. For example, additional protection reduces CI but increases average restoration times (CML/CI).

3.9. Ofgem has given this issue further consideration. There is an inverse relationship between CI and CML/CI at an aggregate level (i.e. across companies). For example, companies with more underground network have both lower CI and longer restoration times. However, this relationship does not hold at the more disaggregated level once the benchmarking is taken into consideration. The targets for CI and CML are calculated based on the disaggregation analysis and reflect companies' own mix of circuits. Further, it is clear that WPD South-West is outperforming the CI benchmark at HV as well as having frontier performance on CML/CI. In light of these factors, Ofgem considers that use of the CML/CI metric remains appropriate.

3.10. Taking the above changes into account, the revised actual and target figures (all shown with 50 per cent weighting on planned interruptions as proposed in the Initial Proposals paragraph 4.34) are set out in the tables below.

Table 3.1 Targets for Customer Interruptions (CIs)

	Actual				Target				
	2001/02	2002/03	2003/04		2005/06	2006/07	2007/08	2008/09	2009/10
CN - Midlands	120	100	113		109	108	106	105	103
CN - East Midlands	77	75	83		78	78	77	77	76
United Utilities	55	66	50		57	57	57	57	57
CE - NEDL	82	76	65		75	75	75	75	75
CE - YEDL	77	63	66		69	69	69	69	68
WPD - South West	101	82	71		84	84	84	84	84
WPD South - Wales	113	96	95		100	98	97	95	94
EDF - LPN	38	36	35		36	36	36	36	36
EDF - SPN	93	88	96		91	89	87	85	83
EDF - EPN	101	85	90		90	89	87	86	84
SP Distribution	59	63	60		61	61	61	61	61
SP Manweb	46	41	49		47	47	47	47	47
SSE - Hydro	115	90	84		96	96	96	95	95
SSE - Southern	98	91	86		91	90	89	88	87
Average	83	75	75		77	76	76	75	74

Table 3.2 Targets for Customer Minutes Lost (CMLs)

	Actual				Target				
	2001/02	2002/03	2003/04		2005/06	2006/07	2007/08	2008/09	2009/10
CN - Midlands	117	101	100		102	98	95	91	87
CN - East Midlands	87	78	85		80	77	73	70	67
United Utilities	62	66	57		60	58	56	55	53
CE - NEDL	84	68	66		71	70	69	68	67
CE - YEDL	73	66	72		69	67	65	63	62
WPD - South West	79	58	50		62	62	62	62	62
WPD South - Wales	83	69	64		72	72	72	72	72
EDF - LPN	41	42	38		40	40	40	40	40
EDF - SPN	93	77	87		81	77	73	68	64
EDF - EPN	77	75	73		74	72	71	69	68
SP Distribution	62	70	73		65	61	58	54	50
SP Manweb	50	50	61		52	50	48	46	44
SSE - Hydro	136	80	76		96	95	94	93	92
SSE - Southern	96	79	76		82	80	79	77	76
Average	80	71	71		72	70	68	66	64

Cost allowances

3.11. The Initial Proposals paper set out cost allowances associated with the targeted improvements in quality.

3.12. The capital expenditure allowances associated with customer interruptions targets have been updated to reflect changes in the levels of targets and improvements discussed above. They have also been revised to reflect further information provided by some of the DNOs. For CN – East Midlands, corrected data on actual performance shows that the size of the improvement required to reach a specified benchmark is less than previously thought, so less capital expenditure is needed.

3.13. A number of DNOs were concerned about the level of the opex allowance provided for benchmark restoration performance. They indicated that it was inappropriate for all DNOs to have a similar allowance given the large variation in the improvements that are required. Further, some suggested that Ofgem's approach would constrain companies to use an opex-based approach to improving restoration times rather than adopting capex alternatives such as increased use of automation which would have greater benefit over the longer-term. There is no such constraint – the cost allowance provides additional revenue and does not represent any attempt by Ofgem to direct how companies should achieve the targets, nor does it provide distorted incentives to adopt a particular solution. Ofgem has revised the level of the allowance to reflect further information from the DNOs on the costs of improvements. The approach has also been amended so that the allowance is based on actual fault rates rather than benchmark fault rates. The level of the allowance per fault takes into account the largest improvement in restoration times required across the DNOs.

Table 3.3 Interruption cost allowances

QOS allowances	Capex (5 yrs) - September update	Difference from Initial Proposals	Restoration costs (5 years) - September update	Difference from Initial Proposals
	£m	£m	£m	£m
CN - Midlands	24.0	1.5	9.2	3.3
CN - East Midlands	8.9	-7.6	10.6	4.2
United Utilities	0.0	0.0	8.9	3.0
CE - NEDL	0.0	0.0	6.1	2.0
CE - YEDL	3.9	-0.1	8.4	2.4
WPD - South West	0.0	0.0	8.1	2.8
WPD South - Wales	6.2	0.0	5.5	2.0
EDF - LPN	0.0	0.0	3.8	1.1
EDF - SPN	21.1	8.1	7.2	2.9
EDF - EPN	22.5	9.1	12.0	4.0
SP Distribution	0.0	0.0	8.5	3.3
SP Manweb	0.0	0.0	7.9	3.4
SSE – Hydro	0.0	0.0	5.2	1.3
SSE – Southern	25.0	0.0	12.1	3.8
Total	111.6	11.0	113.5	39.4

3.14. 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 companies receive an additional allowance which, using the updated information now available, amounts to £1.32m for WPD-South West and £0.33m for WPD – South Wales (per annum, in 2002/03 prices).

Incentive rates

3.15. The Initial Proposals set out a proposed approach to setting incentive rates. Ofgem does not propose to change this approach but has updated the calculations to reflect the changes in the interruption targets set out above. The implied changes to the incentive rates for CIs and CMLs are very small.

Interruption audits

3.16. Since the June Initial Proposals paper Ofgem has given further thought to the appropriate accuracy targets and audit process for interruptions in light of the responses in this area.

Audit process

3.17. Ofgem considers that further steps should be taken to streamline the audit process. The revised process will involve the following stages:

<u>Stage 1 – audit of measurement systems</u>

3.18. The consultants will be required to assess the accuracy of the DNOs' measurement systems by considering:

- ♦ the way in which they have counted consumers using MPANs in their 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 RIGs definitions; and
- ♦ whether Ofgem's reporting template has been correctly populated.

3.19. As this is an area where there is greater potential for inconsistency across DNOs, Ofgem considers that it should be given greater focus in future audits.

<u>Stage 2 – Audit of incidents</u>

3.20. Ofgem considers that the DNOs should submit all their interruption data by incident and restoration stage so that Ofgem can pre-populate the audit template with the selected incident data. Once the interruption data has been submitted at the end of the reporting year, Ofgem will select random audit samples for each DNO. Based on statistical analysis and experience to date, a sample of 150 incidents in total will be chosen, split between HV and above and LV according to their combined contribution to CI and CML in the reporting year.[4] The audit of incidents will then be split into two parts:

- **Part 1 -** The auditors will audit 50 HV and above incidents and 30 LV incidents, and then calculate combined LV and overall accuracies for both CI and CML. If the DNOs meets accuracy thresholds of 92 per cent at LV and 97 per cent overall then the audit would be complete and no adjustment would be made to the DNOs' performance figures;

- **Part 2 –** Where DNOs fail to meet the LV accuracy thresholds in part 1, the process would continue until all incidents in the LV sample have been audited. The combined LV accuracy would then be recalculated. At this point if the DNO failed to meet the 90 per cent accuracy target set out in the RIGs then the appropriate adjustment(s) would be made to annual performance.

  Similarly, where DNOs fail to meet the overall accuracy thresholds in part 1 the process would continue until all incidents in the overall sample have been audited. The combined overall accuracy results would then be recalculated. At this point if the DNO failed to meet the 95 per cent accuracy target set out in the RIGs then the appropriate adjustment(s) would be made to annual performance.

3.21. This approach has a number of potential advantages including that:

- it would reduce the length and cost of the audit process; and

- there would be more focus on DNOs who have greater issues in terms of accuracy.

3.22. Ofgem proposes to adopt this revised approach in order to reduce the regulatory burden given high levels of accuracy shown in previous audits, but will keep this under review and retain the options of more in-depth audits or further streamlining the audits if this appears to be appropriate.

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[4] Subject to the constraint that there is a minimum of 50 LV incidents in the sample.

Exceptional events

3.23. Since the June Initial Proposals document Ofgem has reviewed the proposed methodology for exceptional events, taking into account comments from the DNOs and other parties. Ofgem now intends to introduce the new severe weather restoration arrangements through a statutory instrument rather than a licence condition. Ofgem has also updated the cost allowances for exceptional events, to reflect a number of issues raised by the DNOs.

3.24. This section clarifies the treatment of exceptional events and sets out the revised allowances.

Treatment of severe weather events under the quality of service incentive scheme and supply restoration standards

3.25. Ofgem is proposing the following banding of weather conditions for the quality of service incentive scheme and standards of performance for supply restoration:

- Normal conditions;
- Severe weather conditions including:
  - Category 1 (medium events);
  - Category 2 (large events); and
  - Category 3 (very large events).

3.26. The treatment of each of these categories of events is set out below. The thresholds for each band are set out in Table 3.4 at the end of this section.

Normal conditions

3.27. Normal conditions will be defined as periods when there are no events causing 8 or more times the daily average number of higher voltage faults on a DNO's network in any 24 hour period. Under such circumstances there will be no exclusions for widespread severe weather for the annual quality of service incentive scheme. There may be separate exclusions for one-off events outside a DNO's control (see below).

3.28. Under these conditions domestic consumers 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.

Severe weather conditions

3.29. This includes any events where severe weather causes 8 or more times the daily average number of higher voltage faults on a DNO's network in a 24-hour period. The full audited impact of such events will be excluded from the quality of service incentive scheme and replaced by an equivalent number of days' average performance.

3.30. The treatment of such events under the standards of performance will be based on the category of event.

Category 1 (Medium events)

3.31. These include:

- Lightning events where there are 8 or more times the daily average number of higher voltage faults on a DNOs' network in a 24 hour period, but less than 35 per cent of their exposed consumers[5] are affected;
- Other non-lightning weather events where the number of higher voltage faults on a DNOs' network in any 24 hour period is greater than or equal to 8 times but less than 13 times the daily average number of faults and less than 35 per cent of their exposed consumers are affected.

3.32. Both domestic and non-domestic consumers would be paid compensation of £25 after being off supply for 24 hours with a further £25 for each subsequent 12 hour period up to a cap of £200 per customer.

[5] Exposed customers are defined as customers on mixed or overhead circuits (i.e. those customers that may be affected for 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.

Category 2 (Large events)

3.33. Category 2 weather events are defined as non-lightning events where the number of higher voltage faults in a 24 hour period is greater than or equal to 13 times the daily average and less than 35 per cent of exposed consumers are affected.

3.34. Both domestic and non-domestic consumers will be paid £25 after being off supply for 48 hours with £25 for each subsequent 12 hour period up to a cap of £200 per customer.

Category 3 (Very large events)

3.35. Category 3 events are defined as any weather event where at least 35 per cent of the DNO's exposed consumers are interrupted.

3.36. Ofgem has been giving further consideration to these types of events in light of the severe weather arrangements being formalised in a statutory instrument rather than in the distribution licence. There needs to be a balance between maintaining consumers' existing level of protection for these events and recognising different sets of circumstances. Ofgem proposes that the initial trigger period for compensation will be based on a sliding scale determined by the following formula: 48 hours times the estimated number of consumers interrupted by the event divided by 35 per cent of exposed consumers.

3.37. Both domestic and non-domestic customer will be paid £25 after being off supply for the initial trigger period and a further £25 for each additional period of 12 hours up to a cap of £200.

Table 3.4 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 consumers**
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

Ice accretion and flooding

3.38. Ofgem proposes that for all categories of weather event there should be a delay in the clock starting to count towards the threshold time limit if flooding or ice accretion directly prevents the DNO from carrying out work necessary to restore the consumer's supplies.

Exemptions

3.39. Ofgem proposes that the existing "non-weather" exemptions should continue to apply.

Treatment of other types of exceptional events

3.40. 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 which cause only a small number of incidents but result in substantial numbers of CI and/or CML.

3.41. The proposed approach to determining exceptionality for such one off events is to set separate absolute thresholds for CI and CML so that similar types of exceptional event are captured across companies. For an event to be classified as exceptional it would need to pass one or both of the thresholds.

3.42. Only those events outside the control of the DNO will be considered under this mechanism. 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.

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

3.44. The proposed thresholds are 25,000 consumers 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 below.

3.45. Any CI and CML above these thresholds[6] would 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.

3.46. 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. The following example illustrates the proposed mechanism.

[6] 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. In practice this means that only residual CML above the threshold would be excluded from performance.

Table 3.5 Example of proposed mechanism for "one-off events"

	CI	CI left in annual figures	CML	CML left in annual figures
Event 1	2.00	1.25	3.00	1.00
Event 2	3.00	1.25	0.80	0.80
Event 3	0.75	0.75	1.30	1.00
Total	5.75	3.25	5.10	2.80
Excess removed		2.50		2.30

3.47. As shown in Table 3.5, where an event exceeds both thresholds then both the excess CI and CML are removed so that only the threshold levels of CI and CML remain. Where an event passes the CI threshold but not the CML threshold, then only the excess CI that are removed and vice-versa.

3.48. Table 3.6 shows the estimated number of "one-off" events per DNO per year that meet the CI and CML thresholds respectively.

Table 3.6 Estimated number of "one-off" events per DNO

One-off events thresholds

DNO	Threshold of absolute customer interruptions	Converted into CI using 2003/4 customer numbers	Average number of events per year above CI threshold	Threshold of absolute customer minutes lost	CML threshold	Average number of events per year above CML threshold
CN West	25,000	1.1	1	2,000,000	0.9	6
CN East	25,000	1.0	1	2,000,000	0.8	1
United Utilities	25,000	1.1	0	2,000,000	0.9	0
CE - NEDL	25,000	1.6	2	2,000,000	1.3	0
CE - YEDL	25,000	1.2	1	2,000,000	0.9	0
WPD South West	25,000	1.7	3	2,000,000	1.4	0
WPD South Wales	25,000	2.3	1	2,000,000	1.9	1
EDF - LPN	25,000	1.1	2	2,000,000	0.9	1
EDF - SPN	25,000	1.2	3	2,000,000	0.9	2
EDF - EPN	25,000	0.7	4	2,000,000	0.6	6
SP Distribution	25,000	1.3	1	2,000,000	1.0	3
SP Manweb	25,000	1.7	0	2,000,000	1.4	0
SSE - Hydro	25,000	3.7	0	2,000,000	2.9	1
SSE - Southern	25,000	0.9	4	2,000,000	0.7	2
Average	25,000	1.25	1.6	2,000,000	1.0	1.6

Note: The threshold in actual CI and CML will flutuate year on year as customer numbers change

Auditing exceptional events

3.49. The CI and CML figures will be verified by an audit carried out by Ofgem or Ofgem's appointed auditors. For "one-off" events the auditors will also review the DNOs' mitigating actions and recommend appropriate adjustments to performance.

Changes in the exceptional event allowance

3.50. The DNOs were generally concerned at the level of the allowances in the Initial Proposals and noted that they would be insufficient to cover insurance premia. There were also a number of specific concerns raised including:

- the treatment of flooding;
- that no allowance had been made for fault costs for smaller events; and
- errors in the probabilities of events occurring.

3.51. Ofgem has revised the approach to incorporate flooding events and to include 50 per cent of faults costs for smaller events. Since a significant proportion of smaller exceptional events would not have passed the existing materiality tests, the associated fault costs will have been included in the opex regression.

3.52. The overall exceptional event allowance in Initial Proposals did not cover fault costs or compensation associated with extremely large events. Ofgem has amended the approach to include an allowance for very uncommon events, of a scale that might happen once every 20 years ("1 in 20 year events"). As the cap on revenue exposure to the new weather arrangements is 2 per cent of revenue, and taking account of potentially substantial fault costs to restore supplies permanently following such an event, this allowance has been set at 4 per cent of revenue (to cover both fault costs and compensation) multiplied by the 1 in 20 probability of the event occurring.

3.53. The revised calculation of the exceptional event allowances is set out in the Table below.

Table 3.7 Allowance for exceptional events

DNO	Allowance per exposed customer for medium events		Allowance for major		Allowance for 1 in 20 year events (£m)	Number of exposed customers	Annual allowance for exceptional events (£m)	Initial proposals figures (£m)	Difference (£m)
			Per customer	Per event					
	Lightning	8 times to 13 times	13 times to 20 times	20 +					
	£ 0.12	£ 0.33	£ 1.22	£ 2.87	4% of BPCR				
	Number of events per year								
CN - Midlands	0.6	0.8	0.3	0.4	0.46	990,000	2.3	1.5	0.8
CN - East Midlands	1.0	1.0	0.2	0.3	0.45	1,170,000	2.3	1.3	1.0
United Utilities	0.4	0.5	0.1	0.3	0.40	750,000	1.3	0.9	0.4
CE - NEDL	2.3	0.7	0.3	0.6	0.29	620,000	1.9	1.9	0.0
CE - YEDL	0.6	0.9	0.2	0.2	0.41	990,000	1.6	0.5	1.1
WPD - South West	1.9	0.7	0.0	0.4	0.32	770,000	1.6	1.2	0.4
WPD - South Wales	0.6	0.9	0.2	0.8	0.24	590,000	2.0	2.3	-0.3
EDF - LPN	na	na	na	na	na	na	na	na	na
EDF - SPN	0.4	0.6	0.1	0.2	0.29	810,000	1.1	0.7	0.4
EDF - EPN	0.3	1.5	0.5	0.3	0.55	1,380,000	3.3	1.9	1.4
SP Distribution	0.3	0.7	0.3	0.5	0.51	650,000	1.8	1.6	0.2
SP Manweb	1.0	0.9	0.1	0.4	0.31	540,000	1.2	1.2	0.0
SSE - Hydro	0.7	1.8	1.2	0.4	0.30	340,000	1.4	1.6	-0.2
SSE - Southern	0.0	0.7	0.1	0.5	0.57	1,190,000	2.7	1.6	1.1

3.54. 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 companies.

Targets for electrical losses

3.55. The Initial Proposals document set out Ofgem's initial view for the fixed target level of losses calculated from data for the 10 year period from 1993/94 to 2002/03. DNOs have expressed broad support for the revised incentive framework set out by Ofgem, although three DNOs have identified a number of detailed issues and company specific factors in relation to the calculation of the targets. Following discussions with these companies and consideration of the arguments that they have put forward, Ofgem have made specific adjustments to the losses target for 2005 onwards. These include:

- United Utilities – 0.2 per cent increase in the target to offset adjustments made to consumption data, and agreed with the regulator, over the period 1995/96 to 1997/98. These adjustments were made due to an error in reported consumption and losses data in the period immediately following privatisation;

- SP Manweb – 0.4 per cent increase in the target to remove any distortion arising due to a fall of 3,000 GWh in electricity distributed to EHV sites between 1994/95 and 1998/99; and

- Hydro-electric – 0.1 per cent increase in the target to correct for an error in the calculation of the target associated with the application of the distributed generation adjustment.

3.56. Since the Initial Proposals were published Ofgem has received outturn consumption and losses data for 2003/04. Table 3.8 sets out the final targets for the next price control period. These include the adjustments set out above.

Table 3.8 Losses targets

DNO	Losses target (per cent of units distributed p.a.)	Indicative target June 2004	Difference
CN – Midlands	4.96	5.00	(0.04)
CN – East Midlands	5.69	5.80	(0.11)
United Utilities	5.68	5.38	0.30
CE – NEDL	5.20	5.26	(0.06)
CE – YEDL	5.90	5.93	(0.03)
WPD – South West	6.96	7.01	(0.05)
WPD – South Wales	4.94	4.92	0.02
EDF – LPN	6.54	6.71	(0.17)
EDF – SPN	6.54	6.60	(0.06)
EDF – EPN	6.32	6.49	(0.17)
SP Distribution	6.45	6.47	(0.02)
SP Manweb	7.52	7.28	0.24
SSE – Hydro	8.65	8.56	0.09
SSE – Southern	6.74	6.74	0.00
Weighted average	6.19	6.21	(0.02)

Views invited

3.57. Views are particularly invited on the proposals on:

- the updated targets for interruptions and costs allowances;
- the proposed approach for interruptions audits; and
- the revised proposals for the treatment of exceptional events.

4. Cost assessment

Introduction

4.1. A key part of the price control review is the assessment of companies' future costs. This Chapter provides an update on Ofgem's views on the assessment of operating costs and capital expenditure, and on the associated incentives for efficiency.

Operating costs

4.2. The main issues impacting on the operating cost allowances are:

- Normalisation;
- Cost function (and composite scale variable);
- Regional factors;
- Establishing a benchmark;
- Use of a glidepath;
- Frontier shift;
- Total cost analysis;
- Data envelopment analysis;
- Additional allowances for vegetation, exceptional events and quality improvements;
- Comparison with 2003/04 analysis;
- Comparison with forecasts;
- Mergers; and
- Rates.

4.3. These are addressed in turn below.

Normalisation

4.4. The Initial Proposals paper explained that Ofgem has undertaken substantial work to bring company data onto a more comparable, or "normalised" basis. Since June, there have been some minor adjustments to reflect updated information. Comparison with 2003/04 costs is discussed below.

4.5. The revised normalisation adjustments are summarised in Table 4.1. The right-hand column of this table (totalling £819m) shows the cost values used in the comparative analyses.

4.6. In responding to Initial Proposals, some DNOs have argued that the normalisation work has not achieved comparability across companies. Ofgem considers that the major issues have been addressed, but only after considerable resource has been applied.

4.7. For the future, it will be important to collect cost data on a more comparable basis from DNOs each year, rather than only normalising historical data as part of the price review. Ofgem will be writing to DNOs setting out a proposed timetable for this work and requesting an undertaking from each company that it will commit appropriate resources to this work.

Cost function and composite scale variable

4.8. In the Initial Proposals document, Ofgem used a composite variable to reflect business scale with a 50 per cent weighting on network length, and 25 per cent on each of customer numbers and units distributed.

4.9. In early August, Ofgem held a meeting with all the DNOs to discuss the weighting on the scale variable (between network length, customer numbers and units distributed). Arguments were put forward both for higher and lower weighting on network length.

Table 4.1: Normalisation of DNO's 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
CN - Midlands	66	1	(1)	-	4	(2)	-	67
CN - East Midlands	71	(11)	-	2	-	2	-	63
United Utilities	43	20	-	7	(4)	4	-	70
CE - NEDL	43	(1)	(1)	3	(8)	3	-	41
CE - YEDL	57	(1)	(0)	4	(9)	4	-	54
WPD - South West	40	8	(1)	7	(0)	1	-	54
WPD - South Wales	37	(4)	(0)	6	(0)	0	-	38
EDF - LPN	62	(4)	(2)	7	6	(1)	(6)	62
EDF - SPN	66	1	-	7	-	(5)	-	69
EDF - EPN	88	(8)	(6)	10	6	(4)	-	87
SP Distribution	61	(4)	(5)	-	8	(1)	4	63
SP Manweb	61	(4)	(5)	-	1	(1)	-	53
SSE - Hydro	36	(0)	(1)	0	-	2	0	36
SSE - Southern	63	(3)	(2)	1	3	1	-	63
Total	**793**	**(12)**	**(23)**	**53**	**7**	**4**	**(2)**	**819**

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.

4.10. One DNO argued that its operating costs were almost entirely either fixed or driven by the volume of assets on its network, and that network length was the best indicator of asset volume in this context. Another DNO argued that while asset volumes may bear some relation to operating costs, some activities are driven by plant capacity or load and, in general, unit costs of activities are higher in densely populated areas (cities – particularly London). Several DNOs argued that the use of a single cost driver was inappropriate, with one arguing strongly that quality should be incorporated directly. Other DNOs supported use of 50 per cent weighting on network length or proposed an "agnostic" position of equal one-third weights on each of the three components. Another DNO argued that network length should not be relied upon as it was not measured reliably or audited.

4.11. Some of the DNOs have analysed data from the business plan questionnaires, which shows that the DNOs themselves, on average, allocated approximately half of their operating and fault costs against overhead lines or underground cables, with broadly similar costs per kilometre to lines and cables. While cost allocation is no proof of a causal relationship, this does provide some support to using a significant weighting on network length, as does advice from Ofgem's technical consultants.

4.12. Considering the merits of the arguments, we propose to retain 50 per cent network length, 25 per cent consumers and 25 per cent units distributed.

Regional factors

4.13. 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 of £6.1m for EDF-LPN and £1.6m for SSE-Hydro included in the analysis.

4.14. EDF have argued that its other distribution companies should also receive regional allowances due to higher costs of operating in the South-East of England

– primarily relating to wage and property costs. Ofgem accepts that national wage indices show higher values in the South-East and that this should be considered. The wage indices for EDF-LPN and EDF-SPN are significantly higher than for other areas, followed by EDF-EPN and SSE-Southern.

4.15. With property costs, the issue is less clear. Property costs are higher in the South-East, but each DNO inherited a significant non-operational property portfolio at privatisation and will have benefited from growth in property values. It is not clear that differences in future property costs have not been more than offset by increases in property values which have benefited shareholders.

4.16. However, while differences in wages and property costs may be easiest to quantify, it does not follow that they are more valid bases for adjustment than other geographic differences. For example, it may be that some service areas are more exposed to persistently adverse climatic conditions than others.

4.17. One particular issue relates to the costs of generation in outlying areas and islands in particular. This mainly affects SSE-Hydro, but also WPD-South West (on the Scilly Isles, amounting to slightly less than £1m). SSE-Hydro have argued that the incremental costs associated with generation on Shetland will become a liability of the distribution business under BETTA and that these costs should be recoverable from consumers across GB. Provision for these costs of in excess of £7m per annum (based on a wholesale price of £30/MWh) has been included in the allowance for SSE-Hydro, although it is envisaged that this would be dealt with on a pass-through basis.

4.18. Several DNOs accept that the various impacts approximately offset each other and there would appear to be some validity to this argument. It is therefore appropriate to apply a materiality threshold before making any adjustments.

4.19. The regional factors included in this paper are as noted above but this issue is still under consideration. Of the arguments presented to date, the main candidate for change relates to EDF-SPN based on wage costs (possibly of the order of £3m). Ofgem invites any views on this issue before finalising proposals for November.

Establishing a benchmark

4.20. In the Initial Proposals, Ofgem used the upper quartile to set benchmark costs, to be achieved by 2004/05. All the companies have argued that the analysis should use average costs as the benchmark, which is clearly less challenging than an upper quartile (all else equal). Ofgem considers that failure to use evidence of achievable efficiency improvements would not be in consumers' interests, and that the upper quartile position is sufficiently robust to constitute such evidence.

4.21. Updated versions of the regressions using the data first for 14 licensees and then for the 9 ownership groups in existence at the start of 2002/03 are shown in the figures below. (NCCF refers to normalised controllable costs plus faults.)

Figure 4.1 Base regression using 2002/03 data for 14 companies

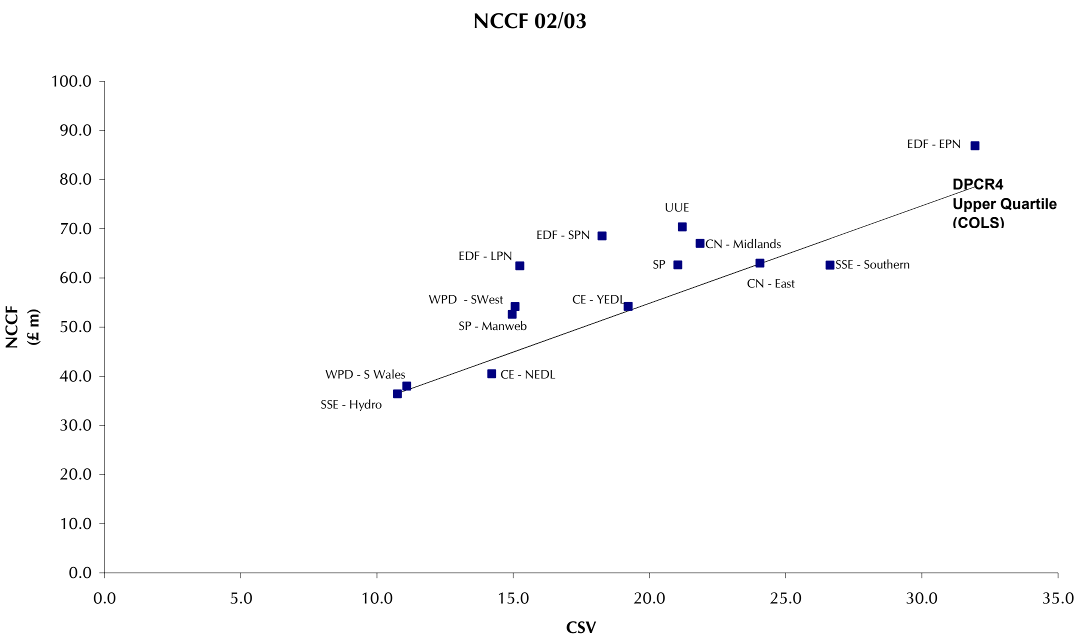
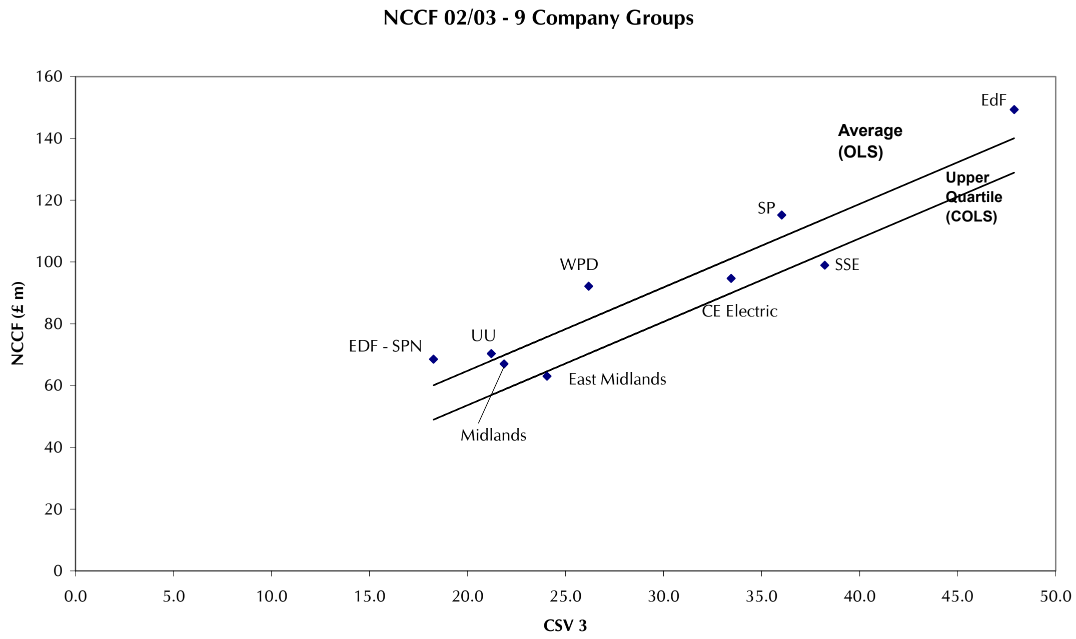


Figure 4.2 Regression using 2002/03 data for 9 ownership groups



Glidepath

4.22. As noted above, in the Initial Proposals, Ofgem assumed that the upper quartile values from the regressions represented efficient cost levels in 2004/05, without any general glidepath beyond the start of the next control period.

4.23. Some companies have argued that this implies unachievable targets, particularly at the start of the price control period. However, the use of an average cost of capital implies that the least efficient companies would be expected to earn below average returns (i.e. have above-benchmark costs). It is therefore not necessary for all companies to achieve the targets in all years, provided the temporary lower returns implied would not preclude a company from financing its activities.

4.24. Use of a glidepath, on the other hand, would provide additional revenue for companies that are shown to be less efficient. This would risk damaging incentives for efficiency. Ofgem therefore does not propose to use a general glidepath.

Frontier shift

4.25. In the Initial Proposals, Ofgem assumed that benchmark costs would continue to reduce by 2 per cent per annum, based on a total factor productivity study and the most aggressive assumption provided by any of the companies. All companies have argued that this is too harsh and the specific company concerned has said that their position was incorrectly/selectively represented. The total factor productivity study suggests a range for operating cost improvement of 0.7 per cent to 3.7 per cent but this relates to average costs – both catch-up to the benchmark and ongoing frontier shift. A figure of 1 – 1.5 per cent would be more capable of being justified by the companies' submissions. However, Ofgem is well aware that companies have in the past exceeded expectations of cost reduction.

4.26. On balance, and taking account of 2003/04 costs as described below, Ofgem considers that a more robust assumption, well within the range supported by the evidence, would be 1.5 per cent and so this figure has been used in the price control calculations in this update.

Total cost analysis

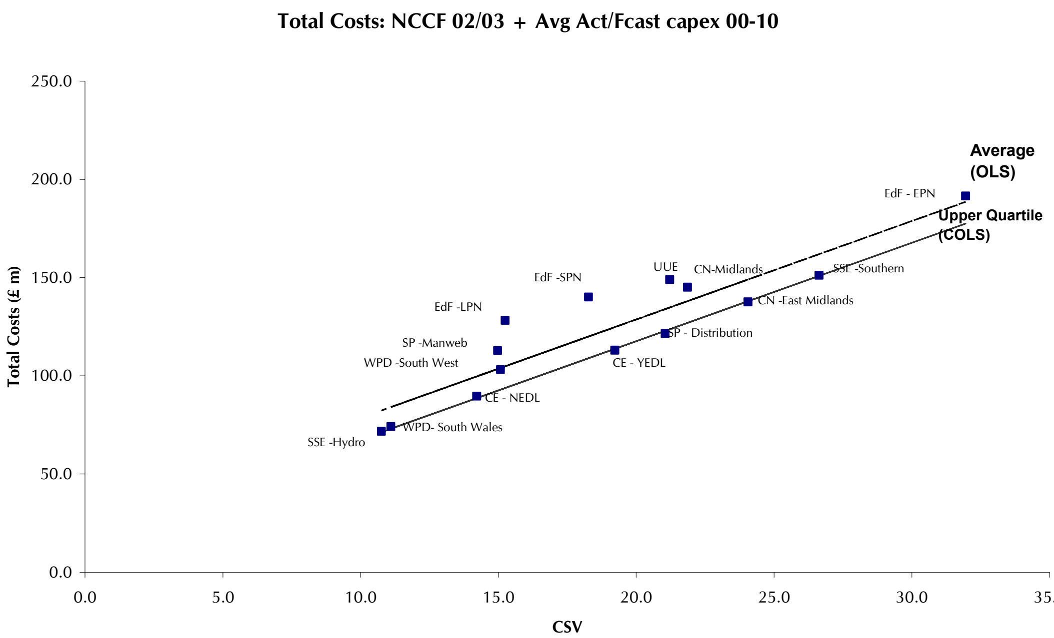
4.27. The Initial Proposals paper presented data on total costs based on 2002/03 opex and a ten year average of capex (2000-2010, including PB Power views beyond 2005), acknowledging that this was not a traditional measure of total costs.

4.28. Some companies have suggested alternative measures of capital consumption, but it is not clear that any of these have more relevance for setting operating cost allowances and it is difficult to make a case that any specific methodology is technically correct. For example, most of the analyses put forward make use of accounting depreciation concepts rather than economic depreciation (for example, ignoring technical progress).

4.29. More generally, it is questionable whether total cost analysis should be used only to set operating cost allowances, rather than to inform total cost or revenue allowances (instead of or as an alternative to the traditional building block approach). For example, if a company appears efficient (to a chosen benchmark) on a total cost basis because it has low capital consumption but high operating costs, it would not necessarily be appropriate to give it a higher operating cost allowance unless this was matched by lower capital cost allowances.

4.30. Nonetheless, Ofgem considers that total cost analysis remains an important consideration. The approach adopted in the Initial Proposals has the advantage of addressing some of the comments made about categorisation of costs between operating costs and capital expenditure. Ofgem therefore intends to retain this approach. An updated version of the total costs regression is shown in Figure 4.3 below.

Figure 4.3 Total cost analysis using average capex 2000-2010



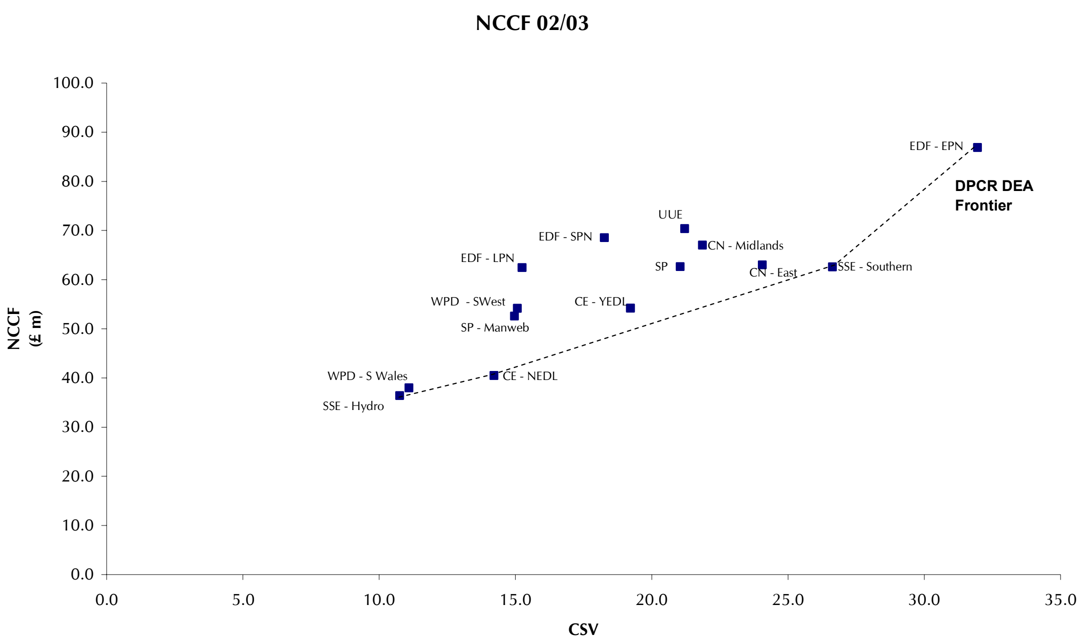
4.31. Ofgem has considered different versions of total cost analysis, including considering a longer run of capital expenditure, back to 1995 or to privatisation. This tends, for example, to improve the relative position of EDF-SPN and worsen the position of SSE-Southern. This analysis has not been used to replace that shown above because: it is less clear that prior years capex is reported on the same basis; some companies have argued that recent capex has a bigger impact on opex; and, using capex from the 1990s would dilute further any benefit of this analysis in offsetting the difference in current allocation of costs between operating costs and capital expenditure.

Data envelopment analysis

4.32. In addition to the regression analysis, Ofgem has considered data envelopment analysis as a cross check. This tool can be used to find the combination of scale factors that best fits the costs of each individual DNO. However, this produces results which imply that the impact of different factors varies more across DNOs than appears to be plausible. The data envelope with multiple outputs cannot easily be graphed.

4.33. A simpler analysis can be undertaken which takes the composite scale variable weightings as given and draws an efficient frontier around the data. This provides the result shown in Figure 4.4, which is arguably more comparable with the regression analysis shown above. Unlike the regression analysis, the frontier is not dependent on a single company. However, the shape of the cost function between Southern and EDF-EPN is dependent on a single company and appears implausible. This analysis would therefore not appear to add significant value to the regression results so has not been used directly.

Figure 4.4 Data Envelopment Frontier with fixed weights



Vegetation, exceptional events and quality improvement

4.34. The Initial Proposals included specific allowances worth a total of £48.8m per year for vegetation management (tree-cutting), exceptional events and quality improvements (increased allowance for fault costs). The latter two areas have been discussed in Chapter 3 above.

4.35. On tree-cutting, Ofgem has reviewed its assumptions in the light of responses from the DNOs and now proposes to base the analysis on the average level of tree cutting costs among the companies making up the upper quartile, instead of the maximum level found among those companies. This results in an increase in the allowance for higher tree cutting activity to £22m per annum across all the companies, compared to £14m in the Initial Proposals (as shown in Table A8 in the Appendix).

4.36. In Initial Proposals and in this paper, the adjustments for increased tree-cutting activity were made after the regression analysis as an additional allowance. An alternative would be to make these adjustments as part of the normalisation work, prior to the regressions. This would reduce allowances for most companies. However, Ofgem is not convinced that this change is necessarily an improvement on the methodology and has therefore not incorporated it here.

4.37. Across vegetation management, exceptional events and additional fault costs the various adjustments now give total allowances of £69.6m per annum, compared to £48.8m in the Initial Proposals.

Comparison with 2003/04 analysis

4.38. Since June, 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. Ofgem therefore does not propose to use 2003/04 as the base year but the data is provided in table 4.2 for reference.

Table 4.2. Actual costs comparison between 2002/03 and 2003/04 (2002/03 prices)

DNO	2002/03 Adjusted Normalised Controllable Costs + Faults	2003/04 Adjusted Normalised Controllable Costs + Faults	Difference
	£m	£m	£m
CN - Midlands	64	75	11
CN - East Midlands	61	62	2
United Utilities	67	69	2
CE - NEDL	38	37	(1)
CE - YEDL	52	52	0
WPD - South West	51	51	0
WPD - South Wales	36	35	(1)
EDF - LPN	59	53	(6)
EDF - SPN	66	63	(3)
EDF - EPN	84	101	16
SP Distribution	58	55	(2)
SP Manweb	51	56	5
SSE - Hydro	33	29	(4)
SSE - Southern	59	60	1
Total	**780**	**799**	**20**

Note: All differences subject to rounding

4.39. In the Initial Proposals, the total 2002/03 adjusted normalised controllable costs plus faults were £778m. The increase to the £780m figure shown above reflects updates to the normalisation analysis since June.

4.40. In aggregate, normalised 2003/04 costs appear to be £799m[7] compared to £780m in 2002/03. The difference can be explained by:

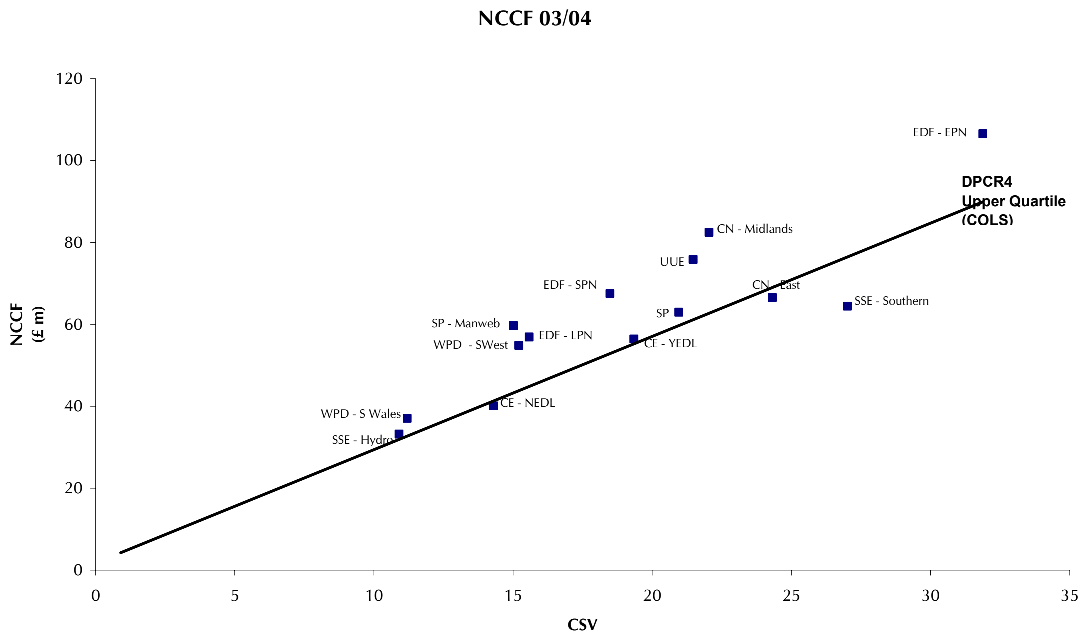
- higher tree-cutting costs – for which an increase has already been included in the proposed allowances;
- lower identified atypicals - which may be real or may simply reflect the relatively limited analysis undertaken; and
- higher corporate cost recharges, particularly at EDF.

4.41. Were it not for these factors, it seems likely that 2003/04 costs would be lower than 2002/03 levels, after adjusting for inflation (i.e. in real prices). Ofgem does not propose to change the allowances specifically to reflect the 2003/04 data.

[7] £799m in 2002/03 prices is equivalent to £821m in 2003/04 prices.

Nonetheless, Figure 4.5 below shows the regression of 2003/04 costs (in 2003/04 prices).

Figure 4.5. Base regression on 2003/04 data for 14 companies



Comparison with forecasts

4.42. The comparison of allowances against the companies' own forecasts is shown in Table 4.3 below.

4.43. 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 – particularly when at WPD the current cost levels are already delivering quality performance that will bring additional revenue in 2005-10.

4.44. This leaves EDF and to a lesser extent UU, where 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. IT and corporate recharges respectively). For EDF in particular, potential cost reductions accounting for a significant portion of the difference between

2002/03 actuals and the proposed allowances were identified by the limited scope review conducted by Ernst & Young. However, it is for company management rather than Ofgem to determine how best to achieve efficient cost levels.

Table 4.3 Comparison of average annual allowance to company forecast (2005-10)

DNO	Company Forecast	September update	Difference
	£m	£m	£m
CN - Midlands	66	59	(6)
CN - East Midlands	60	64	4
United Utilities	73	55	(17)
CE - NEDL	42	43	1
CE - YEDL	53	52	(0)
WPD - South West	55	48	(7)
WPD - South Wales	36	40	4
EDF - LPN	71	51	(21)
EDF - SPN	68	50	(17)
EDF - EPN	100	83	(17)
SP Distribution	55	56	1
SP Manweb	42	47	5
SSE - Hydro	38	38	(1)
SSE - Southern	66	68	2
Total	**825**	**755**	**(70)**

Note: All differences subject to rounding

The company forecasts will include additional tree-cutting expenditures, fault restoration costs and atypical event costs to the extent that the companies have included these factors in their forecasts. This varies across companies.

Mergers

4.45. The Initial Proposals paper included analysis on both a “per licensee” and a “per ownership group” basis but did not otherwise differentiate between merged and non-merged companies. Central Networks (which only merged in January 2004) and, to a lesser extent, United Utilities have argued that comparing them against merged companies is discriminatory because they do not have access to efficiencies of scale.

4.46. There are three ways it is argued that valid comparisons could potentially be drawn: doing comparisons on a "per ownership group" basis, setting the benchmark for "singletons" at a point already being achieved by at least one singleton, or providing an additional allowance for single companies. The latter requires a judgement on the size of the allowance, for which there is little objective evidence. The first two are therefore preferred. In practice, this makes no difference to allowances because CN-East, which was then a single company, is one of the upper quartile companies.

4.47. Nonetheless, it may be arguable that mergers allow companies to accelerate the achievement of cost reductions and, therefore, that non-merged entities will take longer to achieve efficient cost levels. Ofgem welcomes views on whether this is the case and if so, how it should be reflected in price control proposals.

4.48. Looking beyond the current review, it may be useful to re-consider how future mergers that involve a loss of comparators are treated in the next price control period. Ofgem's experience is that comparators are a valuable part of network monopoly regulation – further thoughts on the valuation of comparators will be set out in the forthcoming Regulatory Impact Assessment on gas distribution network sales and respondents to this paper are welcome to include any observations on this issue.

4.49. In addition, there are two other aspects of the policy that Ofgem is considering further:

- implementing the policy ex ante through the price control formula, rather than through specific licence modifications after each merger; and/or
- converting the value per comparator from a fixed £million amount to a percentage of RAV or revenue so that it automatically scales up in proportion to group size (post-merger), consistent with the observation that the detriment increases as the number of comparators reduces.

Rates

4.50. Ofgem proposes that business rates on network assets will be treated as a pass-through item, now that rateable values have been established. The values included for Rates cost in this paper are unchanged from those set out in Table 6.4 of the Initial Proposals paper.

Conclusion

4.51. As shown in Table 4.4 below, Ofgem is now proposing controllable cost allowances of £755m compared to £702m in the Initial Proposals, an increase of 8 per cent.

4.52. As noted above, for the majority of groups, the operating cost allowances are at least broadly in line with the companies' own forecasts.

Table 4.4 Comparison of operating cost allowances in Initial Proposals to September Update (average 2005-10)

DNO	Initial Proposals	September update	Difference
	£m	£m	£m
CN - Midlands	55	59	4
CN - East Midlands	60	64	4
United Utilities	52	55	3
CE - NEDL	40	43	3
CE - YEDL	48	52	5
WPD - South West	46	48	3
WPD - South Wales	37	40	3
EDF - LPN	47	51	3
EDF - SPN	47	50	3
EDF - EPN	76	83	7
SP Distribution	52	56	4
SP Manweb	43	47	4
SSE - Hydro	36	38	2
SSE - Southern	64	68	4
Total	**702**	**755**	**53**

Capital expenditure

Base case capex

4.53. The Initial Proposals paper set out the results of analysis conducted for Ofgem by PB Power and the proposed sliding scale incentives on capex to bridge the gap between PB Power's views and the forecasts of some companies, without disadvantaging those that had provided more reasonable forecasts.

4.54. Ofgem provided a draft of PB Power's report to each company in July and, along with PB Power, met with each company in August to discuss their comments. These discussions have led to minor adjustments to PB Power's views as set out in the table below.

Table 4.5 Change in PB Power view of DPCR4 capex (Base case)

Changes in PB Power view of DPCR4 capex

DNO	June paper	Current view	Change	Reason for change
£m (02/03)				
CN - Midlands	442	444	3	Update/reallocation of adjustments to RAV additions and forecasts.
CN - East Midlands	419	445	27	Re-assessment of forecasts/models (re overhead lines) and update/reallocation of adjustments to RAV additions and forecasts.
United Utilities	439	439	1	Update/reallocation of adjustments to RAV additions and forecasts.
CE - NEDL	254	263	9	Revision of customer contributions and update/reallocation of adjustments to RAV additions and forecasts.
CE - YEDL	314	346	33	Re-assessment of forecasts/models, revision of customer contributions and update/reallocation of adjustments to RAV additions and forecasts.
WPD - South West	251	269	18	Re-assessment of forecasts/models (re overhead lines and diversions) and update/reallocation of adjustments to RAV additions and forecasts.
WPD - South Wales	163	171	8	Re-assessment of forecasts (re diversions)/models and update/reallocation of adjustments to RAV additions and forecasts.
EDF - LPN	387	398	11	Revision of customer contributions and update/reallocation of adjustments to RAV additions and forecasts.
EDF - SPN	414	433	19	Re-assessment of forecasts/models (re reinforcement), revision of customer contributions and update/reallocation of adjustments to RAV additions and forecasts.
EDF - EPN	595	608	14	Re-assessment of forecasts/models (re reinforcement), revision of customer contributions and update/reallocation of adjustments to RAV additions and forecasts.
SP Distribution	332	335	3	Update/reallocation of adjustments to RAV additions and forecasts.
SP Manweb	352	363	10	Re-assessment of forecasts/models (re RMUs, SCADA and Diversions) and update/reallocation of adjustments to RAV additions and forecasts.
SSE - Hydro	184	189	5	Re-assessment of forecasts/models (impact of extreme corrosion conditions on asset life) and update/reallocation of adjustments to RAV additions and forecasts.
SSE - Southern	498	511	13	Correction to forcast by DNO and update/reallocation of adjustments to RAV additions and forecasts.
Total	5,043	5,215	172	

4.55. PB Power's analysis has been conducted on a consistent basis across all companies to provide a common view of what companies should need to spend to maintain current network performance and risk levels.

4.56. The biggest difference between PB Power's views and those of the companies remains with EDF. In part, this may reflect the timing of EDF's investment –

having been relatively low in the current period to date for EDF-LPN and EDF-EPN in particular – but Ofgem considers that consumers should not pay twice for investment. Ofgem remains concerned about this issue and about the scale of the increase proposed by EDF.

Resilience and worst-served consumers

4.57. Of the specific points put by the companies on capital expenditure, several relate to additional expenditures to improve network resilience or performance experienced by worst-served consumers. Previous studies on network resilience 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.

4.58. For many of the projects or programmes of work proposed in the areas of resilience and worst-served consumers, expenditures of over £1,000 per affected customer (incurring financing costs of hundreds of pounds per year per affected customer) would be necessary to deliver significant benefits. This would raise issues of the extent of cross-subsidy. The schemes that are cheapest per customer tend to deliver relatively little benefit or, in some cases, the benefits have not been quantified by the companies concerned.

4.59. In line with the approach taken throughout the review (and at previous reviews), Ofgem does not propose to endorse or reject specific projects. The allowances provided through the sliding scale mechanism create some headroom for companies to undertake expenditure in this area where they can justify it. Based on the examples provided, the costs per affected customer tend to be relatively high and Ofgem is not persuaded that there is sufficient customer benefit to justify additional targeted regulation in this area.

ESQCR

4.60. The Initial Proposals paper excluded the costs of compliance with increased overhead line clearance standards in the Electricity, Safety, Quality and Continuity Regulations (ESQCR) pending further discussion with the DTI (who enforce the regulations) and the companies. These discussions have now taken place and have confirmed that, 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.

Fluid Filled Cables

4.61. 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.

4.62. It appears likely that resolution of this issue will not occur prior to November, in which case it would be necessary to address this issue separately after Final Proposals.

Sliding scale mechanism

4.63. The Initial Proposals set out a possible development of the current regulatory framework to provide for a more flexible approach to capital expenditure, without disadvantaging those companies that have provided more reasonable forecasts.

4.64. Most companies supported the sliding scale mechanism in concept but have continued to argue for higher base capital expenditure allowances plus the sliding scale capex allowance on top. The basis of the sliding scale is that the additional capex allowance is not a "gift" but is intended to provide scope for expenditures above the base case PB Power view.

4.65. Table 4.6 below sets out updated aggregate capex allowances (on the same basis as PB Power view above, excluding capex allowances relating to quality of service and before adjustments in relation to pension costs).

Table 4.6 Comparison of capex allowance to forecast (£m total 2005-10)

	Adjusted company base case forecast	Total allowance	Difference	Allowance forecast
	£m	£m	£m	%
CN - Midlands	485	477	-8	98%
CN - East Midlands	480	476	-4	99%
United Utilities	457	466	9	102%
CE - NEDL	268	277	9	103%
CE - YEDL	358	367	8	102%
WPD - S West	269	283	13	105%
WPD - S Wales	171	179	8	105%
EDF - LPN	543	454	-89	84%
EDF - SPN	489	468	-21	96%
EDF - EPN	856	701	-156	82%
SP Distribution	395	367	-28	93%
SP Manweb	465	406	-59	87%
SSE - Hydro	208	204	-5	98%
SSE - Southern	511	536	25	105%
Total	5956	5661	-295	95%
Increase on 00-05	53%	46%		

4.66. 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. For EDF, the proposed allowances are 65 per cent higher than they will have spent (on a comparable basis) in 2000-05. For SP, the proposed allowances are 57 per cent higher than they will have spent in 2000-05. These are very substantial increases.

Incentives

4.67. As noted above, most respondents to Initial Proposals supported the sliding scale mechanism for capex incentives. One respondent pointed out that the mechanism as set out was not fully incentive compatible, in that the variation in additional returns actually used (in Table 6.10 of Initial Proposals) was insufficiently sharp to compensate for the difference in allowances, even under assumptions of risk-neutrality.

4.68. The sliding scale matrix has therefore been adjusted to preserve incentive compatibility as set out in table 4.7 below. This table has been used to derive the allowances in table 4.6 above and to derive additional returns and incentive rates as set out in table 4.8 below.

Table 4.7 Updated 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

Table 4.8 Sliding scale income and incentive rates

	Ratio of DNO forecast to PBP view	Sliding scale factor	Capex allowance	Additional return	Incentive
CN - Midlands	109%	107.3%	477	0.142%	36%
CN - East Midlands	108%	107.0%	476	0.142%	36%
United Utilities	104%	106.0%	466	0.175%	38%
CE - NEDL	102%	105.5%	277	0.183%	39%
CE - YEDL	103%	105.9%	367	0.183%	39%
WPD - S West	100%	105.0%	283	0.200%	40%
WPD - S Wales	100%	105.0%	179	0.200%	40%
EDF - LPN	136%	114.1%	454	-0.079%	24%
EDF - SPN	113%	108.2%	468	-0.079%	24%
EDF - EPN	141%	115.2%	701	-0.079%	24%
SP Distribution	118%	109.5%	367	0.014%	28%
SP Manweb	128%	112.1%	406	0.014%	28%
SSE - Hydro	110%	107.5%	204	0.183%	39%
SSE - Southern	100%	105.0%	536	0.183%	39%
Total	114.2%	108.6%	5661	0.09%	33%

4.69. The additional return and incentive columns are based on the forecast to PB Power ratio by ownership group, to avoid giving perverse incentives between companies in the same ownership group. If the ownership of the companies changes after the review concludes, consideration would need to be given to which rates to use.

4.70. As is evident from tables 4.7 and 4.8, the "additional income" can be negative although in practice this only applies to EDF. The "penalty" to EDF as a group is less than the benefits that shareholders of its licensees will have gained from underspending the capex allowances in the current price control period. This therefore provides some recompense to consumers to mitigate the risk that they are being required to pay twice for a portion (equivalent to the first five years of return and depreciation) of the same expenditure.

4.71. The maximum adjustment to the incentive rate in table 4.7 is broadly comparable to moving to a three year retention period for efficiency savings. Where the company forecasts cannot be reconciled with Ofgem's proposed allowances, an alternative option might be to revisit cost allowances after three years as well – effectively to set a three year price control and take account of actual performance in 2005 and 2006 before finalising the cost allowances for 2008/09 and 2009/10. This would have significant disadvantages in terms of additional regulatory intervention and would clearly lock in the lower incentive rates for the interim period, but Ofgem would welcome views on this.

4.72. As indicated in Initial Proposals, Ofgem is proposing to equalise incentives on operating costs and capital expenditure for the electricity distribution companies for the forthcoming price control period until a consistent cost reporting framework can be established. This will involve bringing incentives on operating costs in line with those on capital expenditure.

4.73. Some DNOs and other respondents have objected to this proposal or suggested that incentives on operating costs should not be set based on comparisons of capex projections. However, this is necessary if incentives are to be equalised and the sliding scale mechanism is to be used as described above. In any event, there is some degree of correlation in the deviation between company forecasts and proposed allowances for opex and capex. If cost reporting can be improved, it will hopefully be possible to strengthen incentives on operating expenditure.

4.74. There are at least three possible ways of equalising incentives on operating expenditure and capital expenditure:

- making adjustments to allowed revenue in the period 2005-10 to clawback a proportion of operating cost underspend (or compensate for overspend);
- making adjustments at the time of the next price review for the period 2010-15 to clawback underspend/compensate for overspend; or
- treating any over or underspend on operating costs in the same way as capex over or underspend, feeding through into the RAV (albeit with adjustments for difference in tax).

4.75. Ofgem is discussing these options with the companies but at present is minded to make any adjustments at the next price control review rather than prior to 2010. One of the companies has suggested that the choice between the mechanism could be left to the company concerned – this could potentially enable companies that had underspent to return value to consumers sooner.

4.76. It may be necessary to place some restrictions on the costs considered under this mechanism. For example, "actual costs" would need to exclude the impact of provision movements. As all of the DNOs now operate on a largely self-sufficient basis, Ofgem would also not expect to allow recovery of more than a minimal level of allocated "corporate costs".

Views invited

4.77. Views are particularly invited on:

- regional factors and other company specific aspects of operating costs; and
- the approach to equalising capex and opex incentives.

5. Financial issues

Introduction

5.1. This Chapter updates Ofgem's position on selected financial issues:

- base revenues for the price control calculation;
- treatment of pension costs;
- taxation costs;
- RAV roll forward; and
- financial modelling and allowed revenues.

5.2. On other financial issues Ofgem's position remains as set out in June in the Initial Proposals and its related appendices. In particular, the proposals in this document continue to use the mid-point of the cost of capital range (4.6 per cent post-tax, 5.4 per cent on the vanilla WACC basis used in the financial model, 6.6 per cent pre-tax) – Ofgem will assess the overall risk-reward balance of the proposals before deciding on the cost of capital to use in Final Proposals in November.

Base revenues

5.3. The calculation of initial price changes or "P0s" depends on the difference between price controlled revenue in 2004/05 and allowed revenue in 2005/06. Allowed revenue in 2005/06 is calculated based on various cost allowances, less elements of excluded services revenue that correspond to those cost allowances. Hence changes to forecast 2004/05 revenues or the relevant element of excluded services revenues will impact on the P0 changes.

5.4. Since the Initial Proposals, companies have provided Ofgem with updated revenue forecasts for 2004/05. In most cases, these differ by a few million pounds, as shown in table 5.1. The exception is SP Manweb, where much higher revenues are projected for a number of reasons, including losses incentive revenue and correction factor adjustments. The final column of table

5.1 shows the approximate impact on the P0 calculation. For a given level of 2005/06 revenue, higher revenues in 2004/05 implies a smaller positive or more negative change to get to the 2005/06 level, so increases in 2004/05 revenue reduce the P0 change.

Table 5.1 Changes to forecast 2004/05 revenue

	Forecast 04/05 revenue			Approx.
	Current view	Initial proposals	Difference	impact on P0
CN - Midlands	249	244	5	-2%
CN - East	259	256	3	-1%
UU	205	206	-1	0%
CE - NEDL	159	158	1	-1%
CE - YEDL	222	219	3	-1%
WPD-South West	173	170	3	-2%
WPD-South Wales	135	134	1	-1%
EDF - LPN	230	227	3	-1%
EDF - SPN	159	156	3	-2%
EDF - EPN	289	292	-2	1%
SP Distribution	260	263	-3	1%
SP Manweb	183	163	20	-12%
SSE - Hydro	161	157	4	-2%
SSE - Southern	305	308	-3	1%
Total	2989	2952	38	-1%

5.5. In addition, Ofgem has held further discussions with companies to refine the calculation of the elements of excluded services revenue that are netted off total cost allowances to derive price control revenue. This has led to reductions in excluded services revenue for this purpose from £65m to £30m.

Pensions

5.6. The Initial Proposals included allowances for pension costs based on the latest information available at the time, assuming 80 per cent of the deficit fell to distribution,[8] disallowing 100 per cent of unfunded early-retirement deficiency contributions (ERDCs) and spreading the remaining deficit over 13 years. Ofgem

[8] Except for EPN and YEDL where this was clearly not appropriate as only active distribution members were retained when the distribution business was sold to its current owner, so 100 per cent relates to distribution, and three other licensees that had provided indicative calculations suggesting a lower proportion.

indicated that it would make a firm proposal on the treatment of costs associated with ERDCs in this September paper.

5.7. While distribution business consumers should not be expected to pay for pension costs relating to non-distribution activities, Ofgem's principle remains that allowance will be made in setting the distribution price control for pension costs that relate to the distribution business, providing substantial protection for shareholders (and pension fund members) against the market risk of the pension scheme. These proposals adopt that approach.

5.8. This paper incorporates the latest information provided by the companies based on the current actuarial valuations. This generally shows larger deficits due to updated mortality assumptions. Further updated information is likely to become available before November.

5.9. In terms of calculating an annual allowance for contributions to the pension fund to make good the deficit, Ofgem accepts the comments from some companies that it would be appropriate to take account of the effects of investment returns by annuitising the value of the deficit – which increases the annual cost. However, Ofgem has also previously indicated that it will take account of investment returns in calculating ERDC values (which in most cases increases the value of unfunded ERDCs). This paper continues to use an average remaining service life of 13 years pending further information from the companies.

Allocation to distribution

5.10. In Initial Proposals, Ofgem allocated varying portions of the deficit to distribution for different companies, with a default value of 80 per cent. While some companies have told us that they have calculated a higher figure, others have said that any such calculation requires arbitrary assumptions.

5.11. Ofgem has considered undertaking detailed analysis of data to estimate this split for each company. This would require difficult and arbitrary assumptions in at least a proportion of cases and it is unlikely to provide a robust methodology that would not be contested by the companies. Given the costs and time involved, it therefore does not appear to be a worthwhile exercise. Instead, it is proposed to apply a pragmatic assumption of an 80 per cent split where required. The exceptions to this are:

- EDF-EPN and CE-YEDL, where 100 per cent of the deficit has been allocated to distribution since only active distribution members were included when the business was sold to its current owner; and
- SSE-Hydro and SP Distribution, where the figure would be lower because their schemes include generation employees, but the calculation is not required for this price control because their schemes are not in deficit.

Treatment of ERDCs

5.12. Early retirement deficiency contributions are the additional liability borne by the pension scheme due to a member taking early retirement rather than retiring at the normal retirement age. In general (and to the extent considered here), the companies have in the past used the pension fund surplus to cover this liability, rather than contributing funds.

5.13. The Initial Proposals paper noted that various arguments on this issue had merit. In principle, there is a case for not making allowance now for past severance-related costs. However, it appears that these costs were not considered at the time of the last review and that consumers have benefited since as a result of the costs having been incurred. The Initial Proposals referred to a suggestion from some companies that costs should be shared 30 per cent to shareholders and 70 per cent to consumers based on the proportion of permanent operating cost savings retained by each. However, the figures used in Initial Proposals allocated 100 per cent of the costs to shareholders.

5.14. In response to the Initial Proposals, companies have put forward a range of views. Some still argue that the costs should be 100 per cent allocated to consumers. Others have attempted to refine the 30 per cent calculation and argue that a better figure would be 18 per cent – on the assumption that companies on average retain the benefits of efficiency savings for 3 years rather than the 5 years assumed in arriving at the 30 per cent figure.

5.15. In the light of these comments, Ofgem has also considered the 30 per cent calculation further. There is some merit in the companies' argument that they retain the benefit for less than five years on average. However, it could also be argued that the benefit of an early retirement arrangement is only to bring forward a reduction in staff costs, not to create a permanent reduction. For example, staff taking early retirement would generally have been older than most of the active scheme members, and so may have retired without incurring ERDCs sometime in the next ten years or so. Hence the incremental benefit would last less than ten years on average. As an illustrative calculation, the present value of a four year saving (assumed to be retained by the company) over a ten year saving (total) is 48 per cent compared to the 30 per cent noted above.

5.16. It would therefore be possible to sustain an argument that the equitable sharing ratio would be, say, 50:50 rather than 70:30. However, it is important to consider the issue of pension deficit recovery in the context of the overall balance of risk and reward in the price control. For example, the capital asset pricing model contends that the risks that increase a company's cost of capital are those which are correlated with market returns. Distribution companies are generally low risk in this context, but their pension funds are one area where they do bear risk that is correlated with overall financial market performance.

5.17. In adopting an approach that provides the companies with additional protection in this area, Ofgem is reinforcing the low risk characteristics of the distribution business. This reduces the case for arguing that a higher cost of capital is now required to reflect pension-related market risk being borne by the distribution companies.

5.18. Table 5.2 shows the impact of the changes made since the Initial Proposals. There are no changes to the Scottish DNOs because their schemes are not in deficit and they have not revised their pensionable salaries or normal contribution rates.

Table 5.2 Detailed breakdown of pensions adjustments

	Initial Proposals Allowance	Adjustments				Proposed allowance
		Revised Valuations	80 per cent Allocation to Dist'n	Discounting	Revised 70:30 ERDC Split	
	£m	£m	£m	£m	£m	£m
CN - Midlands	6.2	3.8	0.0	0.0	5.6	15.6
CN - East Midlands	9.3	0.5	0.0	-0.1	3.9	13.6
United Utilities	7.5	2.1	0.4	-0.3	4.2	13.9
CE – NEDL	5.2	7.1	0.0	0.9	3.5	16.7
CE – YEDL	6.3	1.1	0.0	0.6	0.5	8.5
WPD - South West	8.5	1.3	0.0	-1.1	5.6	14.3
WPD - South Wales	5.4	1.8	0.0	0.9	2.1	10.2
EDF – LPN	15.2	-1.1	1.4	2.3	2.1	19.9
EDF – SPN	7.3	2.5	0.5	-0.5	4.6	14.4
EDF – EPN	9.5	0.0	0.0	0.7	0.0	10.2
SP Distribution	4.7	0.0	0.0	0.0	0.0	4.7
SP Manweb	11.9	0.2	0.0	2.7	0.4	15.2
SSE – Hydro	3.5	0.0	0.0	0.0	0.0	3.5
SSE – Southern	18.5	3.4	0.0	3.6	2.7	28.2
Totals	119.0	22.7	2.3	9.7	35.2	188.9

Note 1 The above table shows the movement in the pension allowances since the Initial Proposals, split into the main types of change made. These changes inter-relate with each other (eg greater deficits will give greater impact of discounting) so an assumption has to be made about the sequence of these changes in order to illustrate their effect.

Note 2 "Revised valuations" includes the impact of changes to the normal contribution rate, revised pensionable salaries figures and revised deficit figures (where available).

Note 3 "Allocation to Dist'n" shows the impact of moving companies back to a default assumption that 80 per cent of the group deficit applies to Distribution.

Note 4 "Discounting" shows the impact of applying returns to past ERDCs, amortising the allowed deficit over the remaining service life and disallowing 1/13 of the deficit to account for contributions made in 2004/05.

Note 5 The revised ERDC split shows the impact of moving from disallowing 100 per cent of ERDCs to disallowing only 30 per cent.

Tax

5.19. As explained in previous consultation papers, Ofgem has adopted a post-tax approach to determining price control revenues for this price control in order to reflect the additional costs that will be borne by the companies as a result of changes to Inland Revenue rules.

5.20. In response to the Initial Proposals, three main issues were raised in relation to tax:

- the opening balance position of the various tax allowance pools;
- categorisation of costs for tax purposes as operating costs or capital expenditure; and, within capital expenditure, to the various tax pools; and
- the strength of incentives and possible pass-through of tax costs.

5.21. These are examined in turn below. Some of the companies have also questioned Ofgem's inclusion of nominal interest costs as an allowable cost in the taxation calculation, although most appear to accept that this is valid for a tax calculation.

Opening balances

5.22. Ofgem has taken opening balance positions from the companies' actual 2002/03 (or nearest year) tax computations as submitted to the Inland Revenue.

5.23. Some companies have argued that these figures should be adjusted to address such issues as likely adjustments of balances before the computations are agreed by the Revenue, or elements of the opening balances that result from group tax strategies or that the companies consider are not primarily distribution assets.

5.24. Whilst some such adjustments might merit consideration in principle, it would be difficult to adopt a robust and consistent approach and some of the proposed adjustments would appear to amount to retrospective adjustments. Ofgem therefore does not intend to make such adjustments.

Categorisation of costs for tax purposes

5.25. There is significant variation across companies in the proportion of costs that they allocate to the various capital allowance pools. As the tax rules that the companies face will change in April 2005, the incentives that the companies will face to adopt a particular categorisation will also change. The extent to which companies respond to these changing incentives and adopt a tax-efficient position will, in part, determine their tax costs in the period 2005-10.

5.26. The Initial Proposals paper adopted a simple approach of transferring a proportion of capex into operating costs for the tax calculation as a proxy for tax efficiencies. These updated proposals use the same classification between operating costs and capital expenditure for tax purposes as is used in the price control calculations, which results in higher tax allowances.

5.27. The categorisation of capital expenditure between tax pools has been based on generic assumptions, rather than requiring consumers to pay more or less money based on particular accounting treatments adopted by individual companies.

5.27. The effect is set out in Table 5.3 below:

Table5.3 Average Allowances for Tax Costs

	Initial Proposals	September update	Increase
	£m	£m	£m
CN – Midlands	22.7	28.8	6.1
CN – East Midlands	16.7	27.9	11.2
United Utilities	15.8	24.9	9.1
CE - NEDL	11.3	16.6	5.3
CE - YEDL	17.3	22.0	4.7
WPD-South West	14.0	18.4	4.4
WPD-South Wales	12.1	16.7	4.6
EDF - LPN	22.0	26.7	4.7
EDF - SPN	7.9	15.9	8.0
EDF - EPN	17.7	25.0	7.3
SP Distribution	30.2	38.5	8.3
SP Manweb	12.3	16.9	4.6
SSE - Hydro	18.0	22.4	4.4
SSE - Southern	38.1	44.4	6.3
Total	256.0	345.1	89.1

Incentives and risk-sharing

5.28. Irrespective of the level of the allowance for tax, it is proposed to reduce the rewards for outperformance (and penalties for under-performance) as for operating costs. This reduces the risks of us setting the allowance too high or low. However, this will require Ofgem to undertake checks to avoid over-allocation of tax costs to the distribution business.

5.29. Under or over performance would be calculated after adjusting actual tax to remove the effect of group relief and, where net debt is less than 60 per cent of RAV, to take account of the interest shield that would have applied at 60 per cent gearing.

5.30. Some commentators have argued that Ofgem's approach of basing tax calculations on a notional balance sheet with debt to RAV gearing of 60 per cent (as for the cost of capital calculation) amounts to an incentive to increase gearing for those companies that would otherwise be below this level. This appears to be a misunderstanding – all licensees are already part of groups that have (directly or through group relief) access to interest shields of at least this magnitude. For companies with gearing below 60 per cent in the licensed entity but access to group relief, the proposed approach to tax gives the same level of allowed revenue whether the debt that gives rise to the group relief remains elsewhere in the group or is brought into the licensed entity (i.e. the price control calculation does not give a regulatory incentive to increase leverage in the licensed entity in this way). The intention of the approach is to avoid consumers paying more than necessary (given the financial structures and tax positions in place) but to avoid a strong tax incentive to adopt high levels of gearing (above 60 per cent) within the licensed entity.

Regulatory asset value

5.31. The regulatory asset value (RAV) is a measure of the value of the regulated business, based on past investment, on which investors earn a return and receive depreciation. The RAV at 31 March 1998 was established as part of the last price control review. Rolling this forward should simply be a matter of adding actual capital investment and adjusting for depreciation and inflation.

5.32. However, companies have different ways of calculating 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.

5.33. The Initial Proposals set out RAV calculations which, following various adjustments, produced a total RAV at 31 March 2005 for the 14 distribution companies of £12,446m.

5.34. Since June, Ofgem has undertaken detailed review and further analysis. All the adjustments proposed have been updated. The two most contentious adjustments relate to:

- fault repairs; and
- overheads.

5.35. These are discussed in turn below, followed by a summary of the other adjustments that have been made.

Fault repairs

5.36. The Initial Proposals included company-specific adjustments for fault repairs, which relied on a number of assumptions that the companies concerned have questioned. Taking account of these comments, Ofgem has reverted to a simpler approach which rolls forward the monetary adjustments made in the last distribution price control review. As shown in Table 5.4 below, the impact of this change is to increase the RAV by £102m.

5.37. Ofgem has also considered making adjustments for those companies that had clearly changed their approach to capitalisation of faults since 1999. However, the companies concerned had relatively low levels of capitalisation of these costs in 1999 and the changes they made only had the effect of moving their accounting treatment back towards the industry average. Ofgem is therefore not proposing to make adjustments for changes since 1999.

Overheads

5.38. Ofgem requested data from the companies back to 1997/98 (the base year for the last price control review) on the split between direct and indirect costs and the proportion of indirect costs that they capitalised. Approximately half of the companies have provided such data, with the others generally saying that it is unavailable prior to 2001/02 (or even 2002/03). Such data as was provided shows a clear trend of increasing capitalisation, from an average of 28 per cent in 1997/98 to 44 per cent in 2002/03.

5.39. The companies generally accept that some adjustment is warranted, but have argued that moving everyone back to the 1997/98 average would not be appropriate because the nature of the distribution business (both in definition and cost levels) was substantially changed by the last distribution price control review. Some of their arguments have merit and, in particular, use of data before 1 April 2000 might need adjustment (which would have to be on the basis of incomplete information) to reflect changes to the definition of the distribution business made at the 1999 review.

5.40. Ofgem is therefore proposing to use the 2000/01 average capitalisation rate (34 per cent) as a benchmark. Where companies are within 5 percentage points of this rate (i.e. 29-39 per cent), their reported capital expenditure will not be adjusted for this issue. For companies capitalising more than 39 per cent of indirect costs or less than 29 per cent, their reported capital expenditure will be adjusted to bring them back to the edge of the band, to correct for the largest deviations from average accounting practice.

5.41. RAV roll forward adjustments were discussed with the companies in August and there are a small number of detailed points relating to specific data items that are outstanding. These are being considered by Ofgem.

Corporate Costs

5.42. Corporate costs were assumed to be operating expenditure at DPCR3. Consequently, corporate costs allocated to capital have been excluded from RAV additions.

Inter/Intra Company Margins

5.43. Inter/Intra company margins on recharges from companies in the same group have been removed unless the charging entity predominantly receives its revenue from unrelated parties.

Non-Operational Depreciation

5.44. Allowances for non-operational capex were included along with the opex allowance for DPCR3 and so any depreciation on non-operational assets that has been capitalised has been removed.

Overstay Penalties

5.45. Overstay fines were not explicitly considered at DPCR3 but have been excluded from RAV additions to ensure that returns are not earned by companies on fines and penalties.

Pension Costs

5.46. Pension costs capitalised have been adjusted to include the cash paid by DNOs rather than accounting charges, where these differ.

Meter Recertification Costs

5.47. Meter recertification costs have been included in the RAV from April 2000; any meter recertification costs prior to this date have not been included. Any metering costs capitalised but not relating to installation or recertification have been removed.

Impact

5.48. Ofgem considers that these changes represent a more robust set of adjustments than those presented in the Initial Proposals. In aggregate, they have a similar impact, although there are significant differences in the impacts on individual DNOs as shown in Table 5.4 below.

Table 5.4 RAV values at 31 March 2005, prior to separation of metering

Movements in RAV (changes since Initial Proposals)

£m (02/03)	**Published (June 04) RAV**	Indirect cost adjustment	Margins	Faults	03/04 act capex & 04/05 fcst	Other adjusts *	**Current RAV**	Diff to June
Aquila	**951**	0	0	22	19	(11)	**981**	30
EME	**958**	(8)	0	0	7	6	**963**	6
UU	**881**	6	(1)	20	37	(3)	**940**	59
NEDL	**574**	17	16	12	9	(19)	**609**	36
YEDL	**820**	7	4	(5)	2	(8)	**820**	0
WPD - SWest	**733**	(17)	(0)	(9)	14	(9)	**711**	(22)
WPD - SWales	**587**	0	0	(10)	7	2	**586**	(0)
EDF - London	**941**	(7)	(24)	23	(3)	(12)	**918**	(23)
EDF - Seeboard	**666**	(1)	(10)	(9)	8	(0)	**653**	(13)
EDF - Eastern	**1,179**	(30)	(6)	31	(11)	(10)	**1,153**	(25)
SP Distribution	**1,311**	(60)	5	2	0	(3)	**1,255**	(56)
SP Manweb	**762**	(40)	2	2	32	(7)	**750**	(12)
SSE - Hydro	**736**	0	(1)	3	4	(6)	**737**	1
SSE - Southern	**1,350**	(5)	(1)	20	7	(6)	**1,364**	14
	12,446	(138)	(16)	102	133	(87)	**12,439**	(6)

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

5.49. The most material changes since the Initial Proposals paper relate to overheads. This issue was discussed in the Initial Proposals but adjustments were not made at that time.

5.50. Table 5.4 does not make any adjustments for non-operational asset disposals. This issue has been discussed with a number of DNOs and it appears that, across the industry as a whole, consumers will not have been disadvantaged by such disposals as they will not have affected benchmark cost levels. Were the costs of any company to be considered individually, adjustments may be appropriate, but this is not Ofgem's intention at present.

5.51. The RAV calculations presented here rely on the DNOs' own forecasts of 2004/05 capital expenditure. As these forecasts were only updated recently, it is hoped that they will be reasonably reliable. However, where actual 2004/05 capital expenditure is materially different from forecast, Ofgem will assess whether this is due to efficiency before allowing retention of benefits for an extended period.

5.52. In future, it is Ofgem's intention that cost information is collected more regularly so that RAV calculations do not need to be revisited at the next price control review for reasons of cost definition.

Financial profiles

5.53. 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. Some aspects of the model have been changed or updated to ensure this is the case, including reversion to the form of price control calculations used at the last distribution price control review. This model aggregates the allowances for cash costs, plus the opening value of the RAV, less the closing value of the RAV at the end of the five year period, discounted back to the start. The calculations are shown in tables in the Appendix.

5.54. Since June, the version of the financial model underlying the Initial Proposals for each company has been shared with that company. 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 on confidentiality of the data. A version with total industry data (summing the data inputs for all 14 licensees) will be available from Ofgem on request.

5.55. Since June, there have been corrections to the financial model to exclude metering fully and to treat each category of costs consistently throughout the model – as operating costs or capital expenditure or some given split between the two - and other changes to reflect updates to data and modelling assumptions. Costs and revenues associated with distributed generation have also been included to allow an assessment of their impact on financial ratios, although these remain outside the main price control calculation. Consultants have now been engaged to audit the financial model prior to Final Proposals.

5.56. Based on the allowances set out above, the financial modelling undertaken implies that with an X factor of 1 (i.e. RPI-1) as used in Initial Proposals, there would be, on average, price increases of two per cent. To avoid prices rising initially only to fall back in real terms, Ofgem proposes to set an X factor of 0. This allows prices, on average, to be held flat in 2005/06 at the same level as 2004/05 in real terms. The reasons for the changes since Initial Proposals and the resultant P0 values are shown in Table 5.5 below.

Table 5.5 Effect of Incremental Changes in % P0 from Initial Proposals to September Update

DNOs	Initial Proposals	2004/05 Revenue	Model / Data Updates	Pensions	Tax	Opex / Capex	RAV	Reduction in X from 1 to 0	September Paper
CN - Midlands	-6.5%	-2.1%	-2.6%	3.9%	2.5%	1.4%	0.8%	-1.8%	**-4.5%**
CN - East Midlands	-10.8%	-1.3%	-1.3%	1.7%	4.4%	1.7%	-0.1%	-1.8%	**-7.5%**
Unitied Utilities	-1.8%	0.3%	-1.3%	3.1%	4.4%	1.3%	1.7%	-2.1%	**5.6%**
CE - NEDL	-11.5%	-0.8%	-2.6%	7.3%	3.4%	1.6%	1.7%	-1.9%	**-2.9%**
CE - YEDL	-14.7%	-1.4%	-0.2%	1.0%	2.1%	2.1%	-0.2%	-1.7%	**-12.9%**
WPD-South West	-0.2%	-1.9%	-0.4%	3.4%	2.6%	1.7%	-1.5%	-2.1%	**1.6%**
WPD-South Wales	1.7%	-1.0%	0.3%	3.6%	3.4%	1.8%	-0.5%	-2.1%	**7.3%**
EDF - LPN	-2.5%	-1.4%	-2.6%	2.1%	2.1%	1.0%	-0.9%	-1.9%	**-4.2%**
EDF - SPN	-3.7%	-1.6%	0.1%	4.6%	5.1%	1.2%	-0.7%	-2.0%	**3.0%**
EDF - EPN	-4.6%	0.8%	-0.4%	0.2%	2.5%	2.0%	-0.6%	-2.0%	**-2.1%**
SP Distribution	8.4%	1.2%	-0.8%	0.0%	3.2%	1.0%	-0.2%	-2.1%	**10.6%**
SP Manweb	4.0%	-12.3%	-2.5%	2.0%	2.8%	1.8%	0.5%	-1.8%	**-5.5%**
SSE - Hydro	-0.1%	-2.4%	-0.7%	0.0%	2.8%	5.5%	-0.3%	-2.1%	**2.7%**
SSE - Southern	6.1%	1.0%	-2.2%	3.1%	2.0%	1.5%	-0.2%	-2.2%	**9.2%**
Average	**-2.5%**	**-1.6%**	**-1.3%**	**2.4%**	**3.0%**	**1.8%**	**0.0%**	**-2.0%**	**0.0%**

5.57. As explained in previous consultation papers, having calculated allowed revenues, Ofgem then assesses selected financial ratios to check whether the allowed revenues would allow a company with notional gearing in line with the cost of capital gearing assumption to maintain a credit rating comfortably within investment grade. The ratios and threshold values used, as in June, are:

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

5.58. As with the Initial Proposals, excluding the impact of investment related to distributed generation, only one company (EDF-SPN) appears to raise financing issues on the basis of a balance sheet starting from 60 per cent gearing (consistent with the cost of capital assumption). Including the impact of distributed generation at the cost levels forecast by the companies themselves in 2003 has some impact, such as to bring a few other companies to approximately the threshold levels.

5.59. One possible response to this could be to adjust the depreciation profiles. For example, accelerating £10m a year of depreciation at EDF-SPN would bring the FFO interest cover and RCF to debt ratios back within the threshold values, but would increase the P0 from +3 per cent to +11 per cent. The ratio of debt to RAV would still increase to significantly above 65 per cent unless additional equity was injected.

5.60. As noted in the Initial Proposals, there are also some companies with particularly strong financial ratios where it would be possible to defer depreciation and revenue. This is most clearly an issue for the Scottish companies which still have pre-vesting depreciation throughout the period to 2010 and most particularly for SP Distribution because of size of its RAV at privatisation. Deferring £10m per annum of depreciation for SP Distribution for example, would not threaten any of the financial ratio thresholds, would help to level depreciation in the 2005-10 period with that in 2010-15 and would reduce its price increase from +11 per cent to +6 per cent. Based on extrapolation of operating costs and capital expenditure beyond 2010, making this adjustment appears likely to result in smoother long term price trends.

5.61. In any event, issues still under consideration, such as the cost of capital, could have an impact on the financial ratios and it is therefore not appropriate to make any adjustments at this stage.

Views invited

5.62. Views are particularly invited on:

- ♦ whether Ofgem should adjust depreciation profiles either to improve financial ratios or, by exception, to smooth long term price trends; and
- ♦ any new evidence or analysis that Ofgem should take into account in coming to a view on the cost of capital.

Appendix 1 Detailed tables and price control calculations

Table A1: Comparison to June 2004 Initial Proposals (£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		
	September Paper	June Initial Proposals		September Paper	June Initial Proposals		September Paper	June Initial Proposals		September Paper	June Initial Proposals	
	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 (3)**	**DPCR4 5 Year Average Total Opex Allowance**	**DPCR4 5 Year Average Total Opex Allowance**	**Difference Note (4)**
DNO	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
CN - Midlands	67.0	68.2	(1.2)	63.9	63.9	-	59.5	55.1	4.3	74.1	68.8	5.3
CN - East Midlands	63.0	63.0	(0.0)	60.7	60.7	-	64.0	59.6	4.5	81.5	80.2	1.3
United Utilities	70.4	69.3	1.1	67.1	65.1	2.0	55.5	52.4	3.1	66.2	64.5	1.7
CE - NEDL	40.5	40.9	(0.4)	38.2	38.2	-	43.3	39.9	3.4	54.3	48.6	5.7
CE - YEDL	54.2	51.7	2.5	52.1	48.5	3.6	52.3	47.8	4.5	63.3	61.4	1.9
WPD - South West	54.2	53.4	0.8	51.3	51.1	0.2	48.0	45.5	2.5	61.4	59.9	1.4
WPD - South Wales	38.0	38.0	0.0	36.1	35.9	0.2	40.2	37.4	2.7	49.2	46.6	2.6
EDF - LPN	62.4	62.5	(0.0)	59.4	65.5	(6.1)	50.6	47.2	3.4	68.9	72.9	(4.0)
EDF - SPN	68.5	69.3	(0.8)	66.1	66.1	-	50.3	47.0	3.3	56.7	54.6	2.1
EDF - EPN	86.9	88.6	(1.7)	84.4	84.4	-	82.6	76.0	6.6	95.0	92.7	2.3
SP Distribution	62.7	63.8	(1.1)	57.5	57.5	-	56.0	51.8	4.3	78.0	76.1	1.9
SP Manweb	52.6	53.7	(1.2)	51.4	51.4	-	47.0	42.8	4.2	55.9	56.9	(1.0)
SSE - Hydro	36.4	35.0	1.4	32.9	33.3	(0.4)	37.6	35.8	1.8	50.3	42.8	7.5
SSE - Southern	62.6	59.9	2.7	58.5	56.5	2.0	68.1	63.6	4.5	101.2	102.3	(1.1)
Total	**819.3**	817.2	2.1	**779.6**	778.1	1.6	**755.0**	701.9	53.0	**955.9**	928.2	27.7

Notes:

(1) The movement in Normalised Opex + Total Faults is due to 4 key factors:
- an adjustment to increase YEDL's Non-operational Capex has been made to reflect the timing difference of their outsourcing strategy to YEDL's dedicated service provider,
- the intercompany margin deduction has been adjusted to exclude only those margins where the percentage of revenue earned from customers external to the DNO is less than 75% of total revenue, this adjustment affected UUE, WPD and SSE.
- an adjustment to reduce SSE's storms insurance cost was made following updated information,
- the Ofgem pension charge has been updated to reflect the latest view of pensionable salaries and wages and normal contribution rates, this adjustment affected all DNOs.

(2) The movement in Adjusted Normalised Controllable Costs + Faults is due to the first three points included in Note (1) above. There has also been a change in methodology in respect of the regional factor adjustment. In the June Initial Proposals the regional factor adjustment was reversed in Adjusted Normalised Controllable Costs + Faults and the efficiency score was then applied. For the September document however, the regional factor adjustment is not reversed until after the efficiency score has been applied. This has the effect of allowing 100% of the regional factor adjustment for SSE Hydro and EDF-LPN.

(3) The increase in DPCR4 5 Year Average Opex Allowance is due to the effect of the new efficiency scores together with increases in Quality of Supply, Trees and Storm Insurance Atypicals Allowances. The frontier shift has also been adjusted downwards from 2% per annum to 1.5% per annum.

(4) The increase in DPCR4 5 Year Average Total Opex Allowance is due to the points identified in Note (3) above, together with a change in the total pensions allowance and the inclusion of a Shetland allowance for SSE Hydro. The total pensions allowance has increased by approximately £70m from June Initial Proposals, however only 42.3% of the total pensions allowance has been allocated to opex in this document. In the June Initial Proposals, 100% of the total pensions allowance was included as opex. There has also been a change in methodology in respect of the capitalised fault adjustment. For the June Initial Proposals, capitalised faults was calculated as a percentage of the DPCR4 5 Year Average Opex Allowance (ie. after including QoS, Trees, Storms and Ofgem Licence Fee). For the September document, capitalised faults are calculated as a % of Average DPCR4 Opex + Total Faults (Table A6).

Table A2: Movement from June 2004 Initial Proposals Average Total Opex Allowance (£m, 2002/03 prices)

	Notes	**£'m**
June Initial Proposals Proposed Average Total Opex Allowance		928
Movements:		
- Increase in Pension Allowance		71
- Capitalised Pension Allowance Adjustment		(109)
- Increase in QoS, Trees & Storm Insurance Atypicals Allowances		22
- Impact of decrease in frontier shift from 2% to 1.5%		9
- Impact of change in capitalised faults methodology	1	7
- Impact of changes in normalisation adjustments and regression results	2	22
- Inclusion of Shetland allowance for SSE Hydro		7
September Update Proposed Average Total Opex Allowance		**956**

Notes:

1. Impact of change in capitalised faults methodology is offset as this amount is then allowed as capex. The impact has been calculated as the impact of increasing the capitalisation % from 26.00% to 26.23%, the impact of applying the capitalisation % to a different opex + total faults number and the impact of the increase in opex + total faults.

2. Impact of changes in normalisation adjustments and regression results is calculated as the increases in normalised controllable costs + total faults, the impact of the regional factor methodology change and the impact of the revised regression scores.

Table A3: Detailed 2002/03 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)	3.1	0.0	0.0	0.1	0.0	0.0	(0.3)	38.0	25.1	3.9	67.0
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)	2.3	0.0	0.0	2.2	0.9	0.0	(0.3)	30.5	32.5	0.0	63.0
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)	3.3	0.0	0.0	1.5	0.8	(0.4)	(0.3)	42.8	31.2	(3.6)	70.4
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)	2.3	0.0	0.0	2.1	2.3	(0.4)	(0.2)	35.3	12.8	(7.6)	40.5
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)	2.1	0.0	0.0	2.3	3.5	(0.4)	(0.4)	42.9	20.4	(9.2)	54.2
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)	3.0	(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)	2.4	0.0	0.0	0.0	0.0	(0.4)	(0.0)	47.3	21.3	0.0	68.5
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)	2.5	0.0	0.0	0.0	0.0	0.0	(0.0)	48.3	32.4	6.1	86.9
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)	1.4	0.0	3.2	0.0	0.0	0.0	(0.1)	25.7	29.0	7.9	62.7
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)	1.2	0.0	0.0	0.0	0.0	0.0	(0.1)	21.6	30.0	1.0	52.6
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)	1.9	(1.4)	1.6	1.0	0.0	0.0	(0.1)	29.8	6.6	0.0	36.4
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)	4.1	0.0	0.0	1.0	0.0	0.0	(0.1)	39.4	20.4	2.8	62.6
	Total	**677.2**	**3.0**	**(167.8)**	**4.7**	**517.1**	**(15.1)**	**(9.0)**	**52.8**	**(72.9)**	**(1.5)**	**(23.4)**	**34.4**	**(5.8)**	**4.8**	**10.6**	**7.9**	**(1.6)**	**(2.1)**	**496.2**	**316.5**	**6.6**	**819.3**

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 following changes have been made to the June Initial Proposals Normalisation Adjustments:
- an adjustment to increase YEDL's Non-operational Capex has been made to reflect the timing difference of their outsourcing strategy to YEDL's dedicated service provider,
- Intercompany margins have been excluded from DPCR4 Normalised Controllable Costs where the percentage of revenue earned from customers external to the DNO is less than 75% of total revenue, this adjustment affected UUE, WPD and SSE,
- an adjustment to reduce SSE's storms insurance cost was made following updated information,
- the Ofgem pension charge has been updated to reflect latest view of pensionable salaries and wages and normal contribution rates, this adjustment affected all DNOs. The charge has been allocated 100% to opex, thereby reducing fault costs by the relevant pensions element, as an accurate split between opex & faults could not easily be determined.

Table A4: Calculation of DPCR4 Adjusted Normalised Controllable Costs + Total Faults (£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	67.0	-	-	(3.1)	63.9
CN - East Midlands	63.0	-	-	(2.3)	60.7
United Utilities	70.4	-	-	(3.3)	67.1
CE - NEDL	40.5	-	-	(2.3)	38.2
CE - YEDL	54.2	-	-	(2.1)	52.1
WPD - South West	54.2	-	-	(2.9)	51.3
WPD - South Wales	38.0	-	-	(1.9)	36.1
EDF - LPN	62.4	-	-	(3.0)	59.4
EDF - SPN	68.5	-	-	(2.4)	66.1
EDF - EPN	86.9	-	-	(2.5)	84.4
SP Distribution	62.7	(3.2)	(0.5)	(1.4)	57.5
SP Manweb	52.6	-	-	(1.2)	51.4
SSE - Hydro	36.4	(1.6)	-	(1.9)	32.9
SSE - Southern	62.6	-	-	(4.1)	58.5
Total	**819.3**	**(4.8)**	**(0.5)**	**(34.4)**	**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 DPCR4 Base Operating Costs + Total Faults Allowance (£m, 2002/03 prices)

2000-2010

		Base Analysis 14 DNOs		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**	**Reverse 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	K (= C + I + J)	K
	£m		£m		£m		£m	£m	£m	£m	£m	£m
CN - Midlands	63.9	87%	55.8	88%	56.0	88%	56.0	55.9	0.1	-	55.9	53.4
CN - East Midlands	60.7	100%	60.6	100%	60.9	103%	62.2	61.2	0.6	-	61.2	58.5
United Utilities	67.1	81%	54.5	83%	55.7	81%	54.2	54.8	0.3	-	54.8	52.4
CE - NEDL	38.2	107%	40.9	99%	37.8	95%	36.3	38.3	-	-	40.9	39.1
CE - YEDL	52.1	98%	51.2	101%	52.4	95%	49.5	51.0	-	-	51.2	49.0
WPD - South West	51.3	83%	42.7	90%	46.2	76%	39.1	42.7	-	-	42.7	40.8
WPD - South Wales	36.1	98%	35.3	98%	35.5	76%	27.5	32.8	-	-	35.3	33.8
EDF - LPN	59.4	73%	43.2	73%	43.5	86%	51.3	46.0	2.8	6.1	52.1	49.8
EDF - SPN	66.1	75%	49.6	78%	51.4	71%	47.3	49.4	-	-	49.6	47.4
EDF - EPN	84.4	90%	76.2	93%	78.2	86%	72.9	75.8	-	-	76.2	72.9
SP Distribution	57.5	91%	52.3	101%	58.2	84%	48.4	53.0	0.7	-	53.0	50.6
SP Manweb	51.4	85%	43.8	82%	42.1	84%	43.2	43.0	-	-	43.8	41.9
SSE - Hydro	32.9	100%	33.0	99%	32.7	104%	34.2	33.3	0.3	1.6	34.9	33.3
SSE - Southern	58.5	109%	63.5	100%	58.4	104%	60.8	60.9	-	-	63.5	60.7
Total	**779.6**		702.8		708.9		682.9	698.2	4.8	7.7	715.3	683.7

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: DPCR4 Operating Costs + Total Faults Allowance - Average (£m, 2002/03 prices)

				Opex Allowance Buildup										
DNO	**Average DPCR4 Opex + Total Faults Allowance (1.5% Frontier Shift)**	**Capitalisation % Adjusted**	**Average DPCR4 Opex Allowance (1.5% Frontier Shift)**	**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)**	**Total Pension Allowance**	**Capitalised Pension Allowance Adjustment (note 3)**	**Capitalisation faults and non operational capex (note 1)**	**DPCR4 5 Year Average Total Opex Allowance (1.5% Frontier Shift)**
	£m	%	£m	£m	£m	£m	£m	£m	£m	£m		£m		£m
CN - Midlands	53.4	26%	39.4	2.3	1.9	1.8	59.5	1.1	21.0	-	15.6	(9.0)	(14.0)	74.1
CN - East Midlands	58.5	26%	43.2	2.3	1.1	2.1	64.0	1.1	25.9	-	13.6	(7.8)	(15.4)	81.5
United Utilities	52.4	26%	38.7	1.3	-	1.8	55.5	1.1	17.5	-	13.8	(8.0)	(13.7)	66.2
CE - NEDL	39.1	26%	28.8	1.9	1.1	1.2	43.3	0.7	13.4	-	17.0	(9.8)	(10.3)	54.3
CE - YEDL	49.0	26%	36.1	1.6	0.1	1.7	52.3	1.0	19.1	-	8.8	(5.1)	(12.8)	63.3
WPD - South West	40.8	26%	30.1	1.6	2.7	2.9	48.0	0.7	17.2	-	14.6	(8.4)	(10.7)	61.4
WPD - South Wales	33.8	26%	24.9	2.0	3.0	1.4	40.2	0.5	13.1	-	10.3	(6.0)	(8.9)	49.2
EDF - LPN	49.8	26%	36.7	-	-	0.8	50.6	1.0	21.9	-	20.0	(11.5)	(13.1)	68.9
EDF - SPN	47.4	26%	35.0	1.1	0.4	1.4	50.3	1.0	11.6	-	14.5	(8.4)	(12.4)	56.7
EDF - EPN	72.9	26%	53.8	3.3	4.0	2.4	82.6	1.6	25.6	-	10.4	(6.0)	(19.1)	95.0
SP Distribution	50.6	26%	37.3	1.8	1.9	1.7	56.0	0.9	32.4	-	4.6	(2.7)	(13.3)	78.0
SP Manweb	41.9	26%	30.9	1.2	2.3	1.6	47.0	0.7	12.8	-	15.2	(8.8)	(11.0)	55.9
SSE - Hydro	33.3	26%	24.6	1.4	1.8	1.0	37.6	0.3	12.7	7.1	3.4	(1.9)	(8.7)	50.3
SSE - Southern	60.7	26%	44.8	2.7	2.3	2.4	68.1	1.3	35.9	-	28.0	(16.2)	(15.9)	101.2
Total	683.7		504.3	24.5	22.4	24.3	755.0	13.0	280.0	7.1	189.7	(109.5)	(179.4)	955.9

Notes:

1. The capitalised faults and non operational capex has been calculated as 26.23% 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. The capitalised pensions allowance adjustment has been calculated as 57.7% of total average pensions allowance.

4. The movements in the additional opex allowances have been explained in detail in Chapter 4.

Table A7: Adjusted DNOs Base Case Forecasts 2006 - 2010

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)	(34)	(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**	**(54)**	**49**	**(2)**	**8**	**(12)**	**(36)**	**(58)**	**(94)**	**33**	**91**	**9**	**(16)**	**(35)**	
Total Adjusted DPCR4 Opex Forecast	**329**	**300**	**364**	**212**	**263**	**277**	**180**	**357**	**338**	**498**	**277**	**210**	**192**	**330**	
Adjusted DPCR4 Average Forecast	**66**	**60**	**73**	**42**	**53**	**55**	**36**	**71**	**68**	**100**	**55**	**42**	**38**	**66**	**825**

Notes:
1. NTR Costs for CN - Midlands have been increased to reflect the correct costs of NTR as included in CN - Midlands forecast.

Table A8 Increase in allowance for vegetation management

DNO	CSV	Upper Quartile Cost per CSV £k	Annual Cost implied using Upper Quartile Cost x CSV (i.e. costs allowed in regressed costs) £m	Average Annual Model Costs £m	Increased Allowance (Higher of regressed or modelled costs) £m	Increase in allowance for change in activity level £m	Increase in allowance for change in activity level (Initial proposals) £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)	% 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
	Note 1 £m	Note 2 & 4 £m		Note 3 £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	543	*109%*	398	*53%*	*136%*
EDF - SPN	283	489	*72%*	433	*53%*	*113%*
EDF - EPN	438	856	*96%*	608	*39%*	*141%*
SP Distribution	253	395	*56%*	335	*32%*	*118%*
SP Manweb	240	465	*94%*	363	*51%*	*128%*
SSE - Hydro	165	208	*26%*	189	*15%*	*110%*
SSE - Southern	375	511	*36%*	511	*36%*	*100%*
Total	3,882	5,956	53%	5,215	34%	114%

Notes

1 DPCR3 RAV additions less meters and all faults. The adjustment made in the Initial Proposals Paper in July for indirect costs capitalised was based on the 2002/03 normalisation adjustment but a similar adjustment was not made in the RAV rollforward. The adjustments for overheads, margins and other are now consistent with the adjustments to RAV.

2 Company forecasts have been adjusted to exclude ESQCR costs, meters, capitalised faults, fluid filled cable replacement costs, intercompany margins, lane rentals and pension deficit funding costs. An adjustment has also been made for capitalised overhead in line with the 2002/03 normalisation adjustment.
The apportionment of these adjustments has been revised since the initial proposals in June and there have also been some amendments to forecasts by some DNOs.

3 Allowances are PB Power's view of efficient capex and as well as the items in note 2 include adjustments made as a result of reviewing DNOs FBPQ base case forecasts. For comparability purposes these figures include normal pension costs but exclude any pension deficit funding costs.

4 Fluid filled cable replacement (totalling £155m) has been excluded from the EDF company forecasts. Other DNOs have these cables but only forecast replacement of £5 - 10m. The issue of replacement of fluid filled cables is being considered further for all DNOs.

Table A10: Derivation of DPCR 4 Capital Expenditure Allowances (£m, 2002/03 Prices)

DNOs	Base Capex	Less pensions component	Sliding Scale	Quality of Service Allowance	Capitalised Faults and Non Op Capex	Capitalised Pensions	Total Capex Allowance
	£m	£m	£m	£m	£m	£m	£m
CN - Midlands	444	(11)	33	24	70	45	**605**
CN - East Midlands	445	(9)	31	9	77	39	**592**
Unitied Utilities	439	(13)	27	-	69	40	**562**
CE - NEDL	263	(14)	15	-	51	49	**364**
CE - YEDL	346	(15)	21	4	64	25	**446**
WPD-South West	269	(13)	14	-	54	42	**365**
WPD-South Wales	171	(9)	9	6	44	30	**250**
EDF - LPN	398	(11)	56	-	65	58	**566**
EDF - SPN	433	(6)	36	21	62	42	**587**
EDF - EPN	608	(21)	93	23	96	30	**828**
SP Distribution	335	(12)	32	-	66	13	**434**
SP Manweb	363	(11)	44	-	55	44	**494**
SSE - Hydro	189	(7)	14	-	44	10	**250**
SSE - Southern	511	(12)	26	25	80	81	**710**
Total	**5,215**	**(164)**	**446**	**112**	**898**	**547**	**7,053**

Notes:
1. This table shows the derivation of the capital expenditure allowances - the columns do not constitute separate allowances.
2. Load and non load related expenditure excludes pension costs.
3. Capitalised faults and non operational capex as shown in table A6 in Appendix 1

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)	(26)	(5)	(14)	(15)	(21)	(2)	(3)	(96)
Non-operational depreciation	(16)	-	-	(6)	(6)	(6)	(3)	(13)	(9)	(14)	(14)	(14)	(5)	(9)	(115)
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)	-	-	-	-	-	(4)	(3)	(20)
Fault expenditure	-	-	(15)	-	(56)	-	-	-	(46)	-	(4)	(2)	-	-	(124)
Indirect costs capitalised	1	(4)	11	16	6	(9)	-	(7)	(1)	(25)	(40)	(23)	-	(5)	(80)
Meter recertification expenditure	(10)	18	(1)	1	(7)	11	8	-	-	-	(7)	(3)	(3)	(5)	1
	(32)	5	(12)	(1)	(68)	(21)	0	(54)	(65)	(59)	(89)	(71)	(16)	(30)	(513)
Net additions	**498**	**474**	**575**	**331**	**390**	**356**	**320**	**449**	**362**	**683**	**439**	**394**	**276**	**592**	**6,139**
Depreciation	**(456)**	**(499)**	**(455)**	**(280)**	**(442)**	**(314)**	**(255)**	**(433)**	**(298)**	**(653)**	**(606)**	**(317)**	**(276)**	**(635)**	**(5,918)**
RAV as at 31 March 2004	**976**	**976**	**897**	**594**	**809**	**712**	**587**	**912**	**591**	**1,104**	**1,313**	**727**	**749**	**1,371**	**12,317**
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)	(5)	1	(5)	(7)	(0)	(1)	(24)
Non-operational depreciation	(4)	-	-	(0)	(2)	(1)	(1)	(3)	-	(4)	(4)	(5)	(1)	(1)	(25)
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)	-	(0)	-	(5)	(20)	(18)	-	-	(59)
Meter recertification expenditure	(1)	3	-	0	-	3	2	-	-	-	(1)	(1)	-	-	6
	(7)	(2)	(10)	0	(10)	(13)	(2)	(9)	(10)	(8)	(31)	(30)	(1)	(2)	(134)
Net additions	**90**	**79**	**106**	**59**	**91**	**58**	**42**	**85**	**103**	**145**	**49**	**83**	**37**	**109**	**1,137**
Depreciation	**(85)**	**(91)**	**(64)**	**(43)**	**(80)**	**(59)**	**(44)**	**(79)**	**(41)**	**(96)**	**(108)**	**(60)**	**(50)**	**(116)**	**(1,015)**
RAV as at 31 March 2005	**981**	**963**	**940**	**609**	**820**	**711**	**586**	**918**	**653**	**1,153**	**1,255**	**750**	**737**	**1,364**	**12,439**
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**	**945**	**919**	**594**	**804**	**696**	**574**	**899**	**638**	**1,126**	**1,233**	**735**	**728**	**1,350**	**12,205**

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	5.8	5.8	5.7	5.7	5.7	9.8	15.6	15.6	15.6	15.5	15.5
CN – East Midlands	4.3	4.4	4.4	4.4	4.3	9.2	13.6	13.6	13.6	13.6	13.6
United Utilities	6.5	6.5	6.4	6.3	6.3	7.4	13.9	13.9	13.8	13.8	13.7
CE – NEDL	5.4	5.5	5.7	5.8	5.9	11.3	16.7	16.8	17.0	17.1	17.2
CE – YEDL	5.5	5.6	5.8	5.9	6.0	3.1	8.5	8.7	8.9	8.9	9.1
WPD – South West	6.0	6.1	6.2	6.3	6.5	8.4	14.3	14.5	14.6	14.7	14.8
WPD – South Wales	4.1	4.2	4.2	4.3	4.4	6.1	10.2	10.2	10.3	10.4	10.4
EDF – LPN	5.5	5.6	5.6	5.6	5.7	14.4	19.9	20.0	20.0	20.0	20.1
EDF – SPN	3.9	4.0	4.0	4.0	4.0	10.5	14.4	14.5	14.5	14.5	14.5
EDF – EPN	7.2	7.3	7.4	7.5	7.6	2.9	10.2	10.2	10.3	10.5	10.6
SP Distribution	4.7	4.7	4.6	4.6	4.6	-	4.7	4.7	4.6	4.6	4.6
SP Manweb	3.9	4.0	3.9	3.9	3.9	11.3	15.2	15.2	15.2	15.2	15.1
SSE – Hydro	3.5	3.4	3.3	3.3	3.3	-	3.5	3.4	3.3	3.3	3.3
SSE – Southern	7.0	7.0	6.8	6.7	6.7	21.2	28.2	28.1	28.0	27.9	27.9
Total	**73.3**	**73.8**	**74.1**	**74.4**	**74.7**	**115.6**	**188.9**	**189.5**	**189.7**	**190.0**	**190.4**

Note:

On average across the DNOs the proportion of capex to total costs (capex and opex) is approximately 60 per cent. The price control calculations therefore assume approximately this proportion of the above allowance will be capitalised and the remainder expensed as opex.

Table A13 Allowance for pension deficit funding

DNO	Pension Deficit	Distribution Deficit	Disallowed ERDCs	Allowed Deficit	Deficit Funding per annum
Notes	(1)	(2)	(3)		(4)
	£m	£m	£m	£m	£m
CN – Midlands	139.4	111.5	22.1	89.4	9.8
CN – East Midlands	123.7	99.0	15.2	83.8	9.2
United Utilities	105.2	84.2	16.5	67.7	7.4
CE – NEDL	145.6	116.5	13.6	102.9	11.3
CE – YEDL	29.8	29.8	2.0	27.8	3.1
WPD – South West	122.8	98.2	22.0	76.2	8.4
WPD – South Wales	79.4	63.5	8.3	55.2	6.1
EDF – LPN	173.5	138.8	8.0	130.8	14.4
EDF – SPN	142.2	113.7	18.1	95.6	10.5
EDF – EPN	26.8	26.8	0.0	26.8	2.9
SP Distribution	-	-	-	-	-
SP Manweb	130.2	104.1	1.7	102.4	11.3
SSE – Hydro	-	-	-	-	-
SSE – Southern	253.8	203.1	10.5	192.6	21.2
Total	**1,472.3**	**1,189.2**	**138.0**	**1,051.2**	**115.6**

Notes
(1) Total deficit as advised by companies, reduced by 1/13 for 2004/05 contributions
(2) 80 per cent of total except EPN and YEDL (both 100 per cent)
(3) Adjusted for historic scheme returns
(4) Allowed deficit amortised over 13 years

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	1,013.8	1,058.8	1,097.6	1,130.0
2	Total capex		121.4	121.2	121.0	120.7	120.5
3	Depreciation		(72.3)	(76.2)	(82.3)	(88.3)	(94.4)
4	Closing asset value		1,013.8	1,058.8	1,097.6	1,130.0	1,156.1
5	Present value of opening / closing RAV		964.7				890.5
6	5 Year movement in closing RAV						74.3
	ALLOWED ITEMS						
7	Operating costs		76.6	74.9	73.7	73.1	72.5
8	Capital expenditure		121.4	121.2	121.0	120.7	120.5
9	Tax allowance		28.8	29.3	29.1	28.8	28.3
10	Capex incentive scheme		1.2	0.9	1.0	0.5	0.6
11	Sliding scale additional income		1.4	1.5	1.5	1.6	1.6
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		0.9	-	-	-	-
14	**Total allowed costs**		**230.3**	**227.8**	**226.2**	**224.6**	**223.5**
15	Present value of allowed costs		224.4	210.6	198.6	187.1	176.7
16	5 Year movement in closing RAV						74.3
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,071.6**
	REVENUE						
18	Revenue index		1.000	1.007	1.015	1.022	1.029
19	Discounted revenue index		0.974	0.932	0.891	0.851	0.814
20	**Price control revenue**	**249.1**	**237.8**	**239.6**	**241.4**	**243.1**	**244.8**
21	Excluded services revenue		2.4	2.4	2.4	2.4	2.4
22	Total revenue		240.2	242.0	243.8	245.5	247.2
23	Present value of total revenue		234.0	223.8	213.9	204.5	195.4
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,071.6**
25	PO		(4.5%)				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	1.1%					
28	Exclude metering	(0.6%)					
29	Change in Opex	(9.2%)					
30	Depreciation	(0.8%)					
31	Return	1.7%					
32	Rates	(1.0%)					
33	Tax	6.4%					
34	Other	(2.1%)					
35	**Total**	**(4.5%)**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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		945.3	987.9	1,030.1	1,066.1	1,096.1
2	Total capex		119.0	118.7	118.4	118.3	118.1
3	Depreciation		(76.4)	(76.4)	(82.4)	(88.3)	(94.2)
4	Closing asset value		987.9	1,030.1	1,066.1	1,096.1	1,120.0
5	Present value of opening / closing RAV		945.3				862.7
6	5 Year movement in closing RAV						82.6
	ALLOWED ITEMS						
7	Operating costs		78.6	81.8	83.0	82.2	81.6
8	Capital expenditure		119.0	118.7	118.4	118.3	118.1
9	Tax allowance		29.0	27.8	27.5	27.6	27.4
10	Capex incentive scheme		(0.7)	0.6	(0.5)	(0.6)	(0.2)
11	Sliding scale additional income		1.4	1.4	1.5	1.5	1.6
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		1.5	-	-	-	-
14	**Total allowed costs**		**228.7**	**230.3**	**229.9**	**229.0**	**228.4**
15	Present value of allowed costs		222.8	213.0	201.8	190.8	180.5
16	5 Year movement in closing RAV						82.6
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,091.5**
	REVENUE						
18	Revenue index		1.000	1.009	1.020	1.033	1.044
19	Discounted revenue index		0.974	0.933	0.895	0.860	0.825
20	**Price control revenue**	**259.3**	**239.8**	**241.9**	**244.6**	**247.6**	**250.3**
21	Excluded services revenue		3.5	3.5	3.5	3.5	3.5
22	Total revenue		243.3	245.4	248.1	251.1	253.8
23	Present value of total revenue		237.0	227.0	217.7	209.2	200.7
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,091.5**
25	PO		(7.5%)				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	1.3%					
28	Exclude metering	(1.6%)					
29	Change in Opex	(3.2%)					
30	Depreciation	(2.6%)					
31	Return	1.3%					
32	Rates	0.8%					
33	Tax	6.0%					
34	Other	(9.5%)					
35	**Total**	**(7.5%)**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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		918.7	963.0	1,001.5	1,034.0	1,060.8
2	Total capex		112.8	112.6	112.2	112.1	111.8
3	Depreciation		(68.5)	(74.1)	(79.7)	(85.3)	(90.9)
4	Closing asset value		963.0	1,001.5	1,034.0	1,060.8	1,081.7
5	Present value of opening / closing RAV		918.7				833.2
6	5 Year movement in closing RAV						85.5
	ALLOWED ITEMS						
7	Operating costs		68.2	66.7	66.0	65.4	64.8
8	Capital expenditure		112.8	112.6	112.2	112.1	111.8
9	Tax allowance		22.5	24.8	25.5	26.1	25.7
10	Capex incentive scheme		1.9	1.1	(0.4)	(1.0)	(0.5)
11	Sliding scale additional income		1.6	1.7	1.8	1.8	1.9
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		1.5	-	-	-	-
14	**Total allowed costs**		**208.6**	**206.9**	**205.1**	**204.4**	**203.7**
15	Present value of allowed costs		203.2	191.3	180.0	170.3	161.0
16	5 Year movement in closing RAV						85.5
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**991.4**
	REVENUE						
18	Revenue index		1.000	1.011	1.013	1.022	1.024
19	Discounted revenue index		0.974	0.935	0.889	0.852	0.809
20	**Price control revenue**	**205.2**	**216.6**	**219.0**	**219.4**	**221.4**	**221.8**
21	Excluded services revenue		5.8	5.8	5.8	5.8	5.8
22	Total revenue		222.4	224.8	225.2	227.2	227.6
23	Present value of total revenue		216.7	207.8	197.7	189.3	179.9
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**991.4**
25	PO		5.6%				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	1.5%					
28	Exclude metering	(1.3%)					
29	Change in Opex	(9.0%)					
30	Depreciation	7.9%					
31	Return	2.0%					
32	Rates	1.1%					
33	Tax	6.1%					
34	Other	(2.7%)					
35	**Total**	**5.6%**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper. See chapter 5 for details

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		593.9	622.4	647.2	668.3	685.6
2	Total capex		72.9	72.8	72.8	72.6	72.6
3	Depreciation		(44.4)	(48.0)	(51.7)	(55.3)	(58.9)
4	Closing asset value		622.4	647.2	668.3	685.6	699.3
5	Present value of opening / closing RAV		593.9				538.6
6	5 Year movement in closing RAV						55.3
	ALLOWED ITEMS						
7	Operating costs		53.6	55.0	54.7	54.3	53.9
8	Capital expenditure		72.9	72.8	72.8	72.6	72.6
9	Tax allowance		15.7	16.2	16.6	17.0	17.3
10	Capex incentive scheme		2.7	2.2	1.7	1.1	0.6
11	Sliding scale additional income		1.1	1.2	1.2	1.2	1.3
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		1.8	-	-	-	-
14	**Total allowed costs**		**147.9**	**147.4**	**146.9**	**146.2**	**145.7**
15	Present value of allowed costs		144.1	136.3	128.9	121.8	115.2
16	5 Year movement in closing RAV						55.3
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**701.6**
	REVENUE						
18	Revenue index		1.000	1.014	1.028	1.042	1.056
19	Discounted revenue index		0.974	0.938	0.902	0.868	0.835
20	**Price control revenue**	**158.8**	**154.2**	**156.3**	**158.5**	**160.6**	**162.8**
21	Excluded services revenue		1.2	1.2	1.2	1.2	1.2
22	Total revenue		155.4	157.5	159.7	161.8	164.0
23	Present value of total revenue		151.4	145.7	140.1	134.8	129.6
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**701.6**
25	PO		(2.9%)				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	6.4%					
28	Exclude metering	(1.4%)					
29	Change in Opex	(10.7%)					
30	Depreciation	5.2%					
31	Return	0.8%					
32	Rates	1.1%					
33	Tax	5.3%					
34	Other	(9.6%)					
35	**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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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		804.2	826.4	853.5	876.2	894.2
2	Total capex		89.3	89.2	89.2	88.9	88.9
3	Depreciation		(67.2)	(62.1)	(66.5)	(71.0)	(75.4)
4	Closing asset value		826.4	853.5	876.2	894.2	907.7
5	Present value of opening / closing RAV		804.2				699.1
6	5 Year movement in closing RAV						105.1
	ALLOWED ITEMS						
7	Operating costs		65.7	64.2	62.7	62.2	61.6
8	Capital expenditure		89.3	89.2	89.2	88.9	88.9
9	Tax allowance		19.7	21.4	22.7	23.1	23.2
10	Capex incentive scheme		1.6	0.2	(1.9)	(1.9)	(1.3)
11	Sliding scale additional income		1.5	1.5	1.6	1.6	1.6
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		1.0	-	-	-	-
14	**Total allowed costs**		**178.9**	**176.6**	**174.4**	**173.9**	**174.1**
15	Present value of allowed costs		174.3	163.3	153.1	144.9	137.7
16	5 Year movement in closing RAV						105.1
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**878.2**
	REVENUE						
18	Revenue index		1.000	1.010	1.020	1.030	1.041
19	Discounted revenue index		0.974	0.934	0.895	0.858	0.823
20	**Price control revenue**	**221.8**	**193.1**	**195.0**	**197.0**	**198.9**	**200.9**
21	Excluded services revenue		2.8	2.8	2.8	2.8	2.8
22	Total revenue		195.9	197.8	199.8	201.7	203.7
23	Present value of total revenue		190.8	182.9	175.3	168.1	161.1
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**878.2**
25	PO		(12.9%)				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	2.3%					
28	Exclude metering	(1.9%)					
29	Change in Opex	(6.6%)					
30	Depreciation	(5.8%)					
31	Return	0.2%					
32	Rates	(0.9%)					
33	Tax	5.0%					
34	Other	(5.2%)					
35	**Total**	**(12.9%)**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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	718.5	736.2	750.0	760.2
2	Total capex		73.2	73.3	73.1	73.0	72.9
3	Depreciation		(50.3)	(55.6)	(59.2)	(62.9)	(66.5)
4	Closing asset value		718.5	736.2	750.0	760.2	766.5
5	Present value of opening / closing RAV		695.6				590.4
6	5 Year movement in closing RAV						105.2
	ALLOWED ITEMS						
7	Operating costs		59.4	61.5	62.4	62.0	61.6
8	Capital expenditure		73.2	73.3	73.1	73.0	72.9
9	Tax allowance		17.1	17.7	18.3	19.0	19.8
10	Capex incentive scheme		4.5	4.1	2.8	1.8	0.9
11	Sliding scale additional income		1.4	1.5	1.5	1.5	1.5
12	Quality reward		1.7	1.7	1.7	1.7	1.7
13	DPCR3 costs		1.6	-	-	-	-
14	**Total allowed costs**		**159.0**	**159.7**	**159.8**	**159.1**	**158.4**
15	Present value of allowed costs		154.9	147.6	140.2	132.5	125.2
16	5 Year movement in closing RAV						105.2
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**805.7**
	REVENUE						
18	Revenue index		1.000	1.013	1.027	1.038	1.051
19	Discounted revenue index		0.974	0.936	0.901	0.865	0.831
20	**Price control revenue**	**173.1**	**175.9**	**178.1**	**180.6**	**182.6**	**184.9**
21	Excluded services revenue		2.9	2.9	2.9	2.9	2.9
22	Total revenue		178.8	181.0	183.5	185.5	187.8
23	Present value of total revenue		174.2	167.4	161.0	154.5	148.5
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**805.7**
25	PO		1.6%				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	1.5%					
28	Exclude metering	(2.2%)					
29	Change in Opex	(3.7%)					
30	Depreciation	(0.7%)					
31	Return	(1.0%)					
32	Rates	1.2%					
33	Tax	4.9%					
34	Other	1.6%					
35	**Total**	**1.6%**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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	578.2	580.1	579.4	576.2
2	Total capex		50.3	50.1	50.0	50.0	49.8
3	Depreciation		(45.7)	(48.2)	(50.7)	(53.2)	(55.7)
4	Closing asset value		578.2	580.1	579.4	576.2	570.3
5	Present value of opening / closing RAV		573.6				439.3
6	5 Year movement in closing RAV						134.2
	ALLOWED ITEMS						
7	Operating costs		47.8	49.3	50.1	49.8	49.4
8	Capital expenditure		50.3	50.1	50.0	50.0	49.8
9	Tax allowance		15.4	16.1	16.6	17.2	18.0
10	Capex incentive scheme		(1.7)	(1.1)	(0.9)	(0.3)	(0.1)
11	Sliding scale additional income		1.2	1.2	1.2	1.2	1.1
12	Quality reward		1.3	1.3	1.3	1.3	1.3
13	DPCR3 costs		0.9	-	-	-	-
14	**Total allowed costs**		**115.2**	**116.9**	**118.4**	**119.1**	**119.6**
15	Present value of allowed costs		112.2	108.1	103.9	99.2	94.6
16	5 Year movement in closing RAV						134.2
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**652.3**
	REVENUE						
18	Revenue index		1.000	1.013	1.026	1.037	1.050
19	Discounted revenue index		0.974	0.936	0.901	0.864	0.830
20	**Price control revenue**	**134.8**	**144.6**	**146.4**	**148.4**	**150.0**	**151.8**
21	Excluded services revenue		0.2	0.2	0.2	0.2	0.2
22	Total revenue		144.8	146.6	148.6	150.2	152.0
23	Present value of total revenue		141.1	135.6	130.4	125.1	120.2
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**652.3**
25	PO		7.3%				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	6.5%					
28	Exclude metering	(2.1%)					
29	Change in Opex	(2.9%)					
30	Depreciation	6.2%					
31	Return	(0.2%)					
32	Rates	1.1%					
33	Tax	6.9%					
34	Other	(8.2%)					
35	**Total**	**7.3%**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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		899.2	945.1	986.6	1,022.3	1,052.0
2	Total capex		113.7	113.6	113.4	113.1	113.0
3	Depreciation		(67.8)	(72.0)	(77.7)	(83.4)	(89.0)
4	Closing asset value		945.1	986.6	1,022.3	1,052.0	1,076.0
5	Present value of opening / closing RAV		899.2				828.8
6	5 Year movement in closing RAV						70.4
	ALLOWED ITEMS						
7	Operating costs		66.1	68.7	70.2	69.7	69.2
8	Capital expenditure		113.7	113.6	113.4	113.1	113.0
9	Tax allowance		24.9	25.9	26.7	27.6	28.6
10	Capex incentive scheme		8.9	8.5	4.9	2.7	0.6
11	Sliding scale additional income		(0.7)	(0.8)	(0.8)	(0.8)	(0.8)
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		4.6	-	-	-	-
14	**Total allowed costs**		**217.5**	**215.9**	**214.4**	**212.3**	**210.5**
15	Present value of allowed costs		211.9	199.6	188.1	176.8	166.4
16	5 Year movement in closing RAV						70.4
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,013.3**
	REVENUE						
18	Revenue index		1.000	1.015	1.031	1.047	1.063
19	Discounted revenue index		0.974	0.939	0.905	0.872	0.840
20	**Price control revenue**	**230.2**	**220.6**	**224.0**	**227.4**	**230.9**	**234.5**
21	Excluded services revenue		3.2	3.2	3.2	3.2	3.2
22	Total revenue		223.8	227.2	230.6	234.1	237.7
23	Present value of total revenue		218.0	210.0	202.4	195.0	187.9
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,013.3**
25	PO		(4.2%)				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	1.6%					
28	Exclude metering	0.3%					
29	Change in Opex	(6.5%)					
30	Depreciation	(1.9%)					
31	Return	(0.7%)					
32	Rates	1.1%					
33	Tax	5.9%					
34	Other	(4.0%)					
35	**Total**	**(4.2%)**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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		638.1	709.3	774.6	833.7	886.9
2	Total capex		117.7	117.6	117.5	117.3	117.1
3	Depreciation		(46.5)	(52.4)	(58.3)	(64.2)	(70.0)
4	Closing asset value		709.3	774.6	833.7	886.9	933.9
5	Present value of opening / closing RAV		638.1				719.3
6	5 Year movement in closing RAV						(81.2)
	ALLOWED ITEMS						
7	Operating costs		60.2	59.0	57.8	55.3	51.0
8	Capital expenditure		117.7	117.6	117.5	117.3	117.1
9	Tax allowance		16.7	16.7	15.8	15.3	15.1
10	Capex incentive scheme		(3.9)	(4.4)	(3.7)	(3.5)	(2.5)
11	Sliding scale additional income		(0.5)	(0.6)	(0.6)	(0.7)	(0.7)
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		0.8	-	-	-	-
14	**Total allowed costs**		**191.0**	**188.3**	**186.7**	**183.7**	**180.0**
15	Present value of allowed costs		186.1	174.2	163.9	153.1	142.3
16	5 Year movement in closing RAV						(81.2)
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**738.2**
	REVENUE						
18	Revenue index		1.000	1.009	1.018	1.027	1.037
19	Discounted revenue index		0.974	0.933	0.894	0.856	0.820
20	**Price control revenue**	**158.5**	**163.3**	**164.8**	**166.3**	**167.8**	**169.3**
21	Excluded services revenue		1.6	1.6	1.6	1.6	1.6
22	Total revenue		164.9	166.4	167.9	169.4	170.9
23	Present value of total revenue		160.7	153.9	147.4	141.1	135.1
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**738.2**
25	PO		3.0%				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	4.6%					
28	Exclude metering	(4.0%)					
29	Change in Opex	(8.9%)					
30	Depreciation	10.7%					
31	Return	6.4%					
32	Rates	(0.7%)					
33	Tax	5.0%					
34	Other	(10.1%)					
35	**Total**	**3.0%**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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		1,126.0	1,211.8	1,288.9	1,357.5	1,417.7
2	Total capex		166.2	165.9	165.6	165.5	165.2
3	Depreciation		(80.4)	(88.8)	(97.0)	(105.3)	(113.6)
4	Closing asset value		1,211.8	1,288.9	1,357.5	1,417.7	1,469.3
5	Present value of opening / closing RAV		1,126.0				1,131.7
6	5 Year movement in closing RAV						(5.7)
	ALLOWED ITEMS						
7	Operating costs		95.5	96.1	95.3	94.5	93.8
8	Capital expenditure		166.2	165.9	165.6	165.5	165.2
9	Tax allowance		21.2	23.6	25.4	27.0	27.6
10	Capex incentive scheme		13.9	10.9	7.0	2.3	(0.4)
11	Sliding scale additional income		(0.9)	(1.0)	(1.0)	(1.1)	(1.1)
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		1.6	-	-	-	-
14	**Total allowed costs**		**297.5**	**295.4**	**292.3**	**288.2**	**285.2**
15	Present value of allowed costs		289.8	273.2	256.5	240.1	225.5
16	5 Year movement in closing RAV						(5.7)
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,279.4**
	REVENUE						
18	Revenue index		1.000	1.011	1.021	1.031	1.042
19	Discounted revenue index		0.974	0.935	0.896	0.859	0.824
20	**Price control revenue**	**289.4**	**283.2**	**286.3**	**289.2**	**292.1**	**295.0**
21	Excluded services revenue		1.9	1.9	1.9	1.9	1.9
22	Total revenue		285.1	288.2	291.1	294.0	296.9
23	Present value of total revenue		277.8	266.5	255.4	244.9	234.8
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,279.4**
25	PO		(2.1%)				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	2.1%					
28	Exclude metering	(2.8%)					
29	Change in Opex	(0.2%)					
30	Depreciation	(1.1%)					
31	Return	0.3%					
32	Rates	1.1%					
33	Tax	2.8%					
34	Other	(4.3%)					
35	**Total**	**(2.1%)**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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		1,232.9	1,211.0	1,186.7	1,159.7	1,130.3
2	Total capex		87.3	87.1	86.8	86.7	86.5
3	Depreciation		(109.2)	(111.4)	(113.7)	(116.0)	(118.3)
4	Closing asset value		1,211.0	1,186.7	1,159.7	1,130.3	1,098.5
5	Present value of opening / closing RAV		1,232.9				846.1
6	5 Year movement in closing RAV						386.8
	ALLOWED ITEMS						
7	Operating costs		75.2	79.6	79.0	78.4	77.8
8	Capital expenditure		87.3	87.1	86.8	86.7	86.5
9	Tax allowance		35.2	36.5	38.4	40.2	42.2
10	Capex incentive scheme		(1.6)	(0.9)	0.3	1.1	1.1
11	Sliding scale additional income		0.2	0.2	0.2	0.2	0.2
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		1.5	-	-	-	-
14	**Total allowed costs**		**197.6**	**202.5**	**204.7**	**206.6**	**207.8**
15	Present value of allowed costs		192.6	187.2	179.6	172.1	164.3
16	5 Year movement in closing RAV						386.8
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,282.5**
	REVENUE						
18	Revenue index		1.000	1.008	1.015	1.023	1.031
19	Discounted revenue index		0.974	0.932	0.891	0.852	0.815
20	**Price control revenue**	**259.8**	**287.3**	**289.5**	**291.7**	**293.9**	**296.2**
21	Excluded services revenue		-	-	-	-	-
22	Total revenue		287.3	289.5	291.7	293.9	296.2
23	Present value of total revenue		279.9	267.6	256.0	244.8	234.2
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,282.5**
25	PO		10.6%				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	0.3%					
28	Exclude metering	(2.2%)					
29	Change in Opex	(1.2%)					
30	Depreciation	2.6%					
31	Return	(2.1%)					
32	Rates	3.9%					
33	Tax	8.6%					
34	Other	0.7%					
35	**Total**	**10.6%**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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	782.6	823.1	858.5	888.9
2	Total capex		99.0	98.9	98.7	98.5	98.3
3	Depreciation		(51.8)	(58.3)	(63.3)	(68.2)	(73.1)
4	Closing asset value		782.6	823.1	858.5	888.9	914.0
5	Present value of opening / closing RAV		735.4				704.0
6	5 Year movement in closing RAV						31.5
	ALLOWED ITEMS						
7	Operating costs		58.3	57.1	56.0	54.3	53.9
8	Capital expenditure		99.0	98.9	98.7	98.5	98.3
9	Tax allowance		16.5	17.1	17.2	17.1	16.5
10	Capex incentive scheme		0.0	(1.5)	(2.5)	(2.1)	(1.1)
11	Sliding scale additional income		0.1	0.1	0.1	0.1	0.1
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		0.9	-	-	-	-
14	**Total allowed costs**		**174.8**	**171.6**	**169.5**	**168.0**	**167.6**
15	Present value of allowed costs		170.3	158.7	148.7	139.9	132.5
16	5 Year movement in closing RAV						31.5
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**781.6**
	REVENUE						
18	Revenue index		1.000	1.008	1.017	1.026	1.035
19	Discounted revenue index		0.974	0.932	0.892	0.854	0.818
20	**Price control revenue**	**183.1**	**173.0**	**174.3**	**175.9**	**177.4**	**178.9**
21	Excluded services revenue		1.9	1.9	1.9	1.9	1.9
22	Total revenue		174.9	176.2	177.8	179.3	180.8
23	Present value of total revenue		170.3	162.9	156.0	149.4	143.0
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**781.6**
25	PO		(5.5%)				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	4.6%					
28	Exclude metering	(1.1%)					
29	Change in Opex	(1.7%)					
30	Depreciation	2.2%					
31	Return	3.0%					
32	Rates	(1.2%)					
33	Tax	4.0%					
34	Other	(15.3%)					
35	**Total**	**(5.5%)**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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		727.8	727.5	725.6	722.2	717.4
2	Total capex		50.3	50.2	49.9	49.8	49.7
3	Depreciation		(50.7)	(52.0)	(53.3)	(54.6)	(56.0)
4	Closing asset value		727.5	725.6	722.2	717.4	711.1
5	Present value of opening / closing RAV		727.8				547.7
6	5 Year movement in closing RAV						180.1
	ALLOWED ITEMS						
7	Operating costs		48.6	49.2	50.8	51.9	51.6
8	Capital expenditure		50.3	50.2	49.9	49.8	49.7
9	Tax allowance		20.7	21.7	22.3	23.1	24.2
10	Capex incentive scheme		6.4	5.6	4.1	2.3	0.8
11	Sliding scale additional income		1.3	1.3	1.3	1.3	1.3
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		0.9	-	-	-	-
14	**Total allowed costs**		**128.2**	**128.0**	**128.4**	**128.4**	**127.6**
15	Present value of allowed costs		124.9	118.4	112.7	107.0	100.9
16	5 Year movement in closing RAV						180.1
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**744.0**
	REVENUE						
18	Revenue index		1.000	1.010	1.020	1.030	1.040
19	Discounted revenue index		0.974	0.934	0.895	0.858	0.823
20	**Price control revenue**	**161.1**	**165.4**	**167.1**	**168.7**	**170.4**	**172.1**
21	Excluded services revenue		0.5	0.5	0.5	0.5	0.5
22	Total revenue		165.9	167.6	169.2	170.9	172.6
23	Present value of total revenue		161.7	155.0	148.5	142.4	136.5
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**744.0**
25	PO		2.7%				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	1.1%					
28	Exclude metering	(2.3%)					
29	Change in Opex	(3.8%)					
30	Depreciation	1.3%					
31	Return	(3.1%)					
32	Rates	1.4%					
33	Tax	7.4%					
34	Other	0.7%					
35	**Total**	**2.7%**					

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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details

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	1,393.8	1,427.4	1,453.7	1,472.6
2	Total capex		142.6	142.3	142.0	141.7	141.4
3	Depreciation		(98.8)	(108.6)	(115.7)	(122.8)	(129.9)
4	Closing asset value		1,393.8	1,427.4	1,453.7	1,472.6	1,484.1
5	Present value of opening / closing RAV		1,349.9				1,143.1
6	5 Year movement in closing RAV						206.9
	ALLOWED ITEMS						
7	Operating costs		97.0	101.6	103.3	102.6	102.0
8	Capital expenditure		142.6	142.3	142.0	141.7	141.4
9	Tax allowance		44.0	43.5	43.7	45.0	45.9
10	Capex incentive scheme		8.4	7.8	5.2	1.9	0.1
11	Sliding scale additional income		2.5	2.6	2.6	2.7	2.7
12	Quality reward		-	-	-	-	-
13	DPCR3 costs		1.9	-	-	-	-
14	**Total allowed costs**		**296.4**	**297.7**	**296.9**	**293.8**	**292.2**
15	Present value of allowed costs		288.8	275.3	260.6	244.8	231.0
16	5 Year movement in closing RAV						206.9
17	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,507.2**
	REVENUE						
18	Revenue index		1.000	1.012	1.023	1.035	1.048
19	Discounted revenue index		0.974	0.935	0.898	0.862	0.828
20	**Price control revenue**	**305.0**	**333.2**	**337.1**	**341.0**	**345.0**	**349.0**
21	Excluded services revenue		1.9	1.9	1.9	1.9	1.9
22	Total revenue		335.1	339.0	342.9	346.9	350.9
23	Present value of total revenue		326.5	313.4	300.9	289.0	277.4
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,507.2**
25	PO		9.2%				
26	X		0.0%				
	Analysis of PO (%):						
27	Include EHV	3.0%					
28	Exclude metering	(1.0%)					
29	Change in Opex	1.2%					
30	Depreciation	(1.3%)					
31	Return	(1.2%)					
32	Rates	0.6%					
33	Tax	8.3%					
34	Other	(0.4%)					
35	**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 exclude the costs of NTR and metering but include the costs of EHV on pre March 2005 assets.
3. Excluded services revenue excludes NTR, metering, and EHV on pre March 2005 assets.
4. NTR's are therefore excluded from both revenue and costs.
5. These revenue lines are before the application of the merger term.
6. The above calculation of price controlled revenue has changed since the initial proposals paper.
See chapter 5 for details