Electricity Distribution Price Control Review

Initial proposals

June 2004 145/04

Summary

Context of the price control review

Ofgem's principal objective is to protect the interests of consumers – in terms of both the charges they pay and the quality of service they receive. For the regulated monopoly networks, challenging but achievable cost targets need to be set, together with appropriate incentives to invest in the network and deliver a good quality of service in both the short and long term. All previous price control reviews have had similar objectives but this price control review faces significant new challenges.

There is acceptance that investment to replace network assets and to improve network performance needs to increase but a wide range of views on the extent of this change. The new price controls must recognise the requirement for increased investment over the next five years and beyond. Incentive regulation provides the best way to promote efficient delivery of that increased investment.

There is also a sharper focus on quality of service. Consumers value a reliable supply of electricity. A survey undertaken as part of the price control review has shown that consumers are willing to pay more for improved service – but only up to a certain level.[1] Companies and Ofgem itself have developed a better understanding of the factors relating to quality of service and how investment and improved operational practices can raise performance. Such factors will be reflected in the revised arrangements for quality of service.

The challenges raised in the Energy White Paper[2] for renewable energy will require investment in the distribution networks and significant adjustment to the regulatory framework.

A key strength of the regulatory system is that it can and does respond to such challenges and evolve over time. Some of these challenges can be foreseen and are reflected in the initial proposals – others may follow.

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[1] "Consumer expectations of Distribution Network Operators and willingness to pay for improvements in service", Accent Marketing and Research, June 2004.
[2] "Our energy future – creating s low carbon economy", February 2003.

Such developments in incentive regulation build on a system of incentive regulation that has already delivered lower prices and significant benefits for both consumers and companies. Since 1999 companies have achieved significant efficiency savings and are investing over £1 billion per year in the networks. Since 2001/02 quality of service has improved by around 7 per cent. Incentive regulation should not dictate to companies how they should operate and invest in their networks. Companies should take these decisions and be responsible for their consequences.

The key theme for this price control review has been to ensure that the regulatory framework responds to the challenges it faces whilst continuing to deliver benefits to both consumers and companies. This involves maintaining pressure on distribution companies to be efficient, whilst facilitating higher investment, delivering a better quality of service and promoting the connection of new generation, including renewable generation, to distribution networks. The initial proposals address these aims and provide consumers with value for their money. Ofgem shall, however, continue to work with the distribution companies, consumers and their representatives and other stakeholders to refine the approach so that final proposals can be published in November. An update on the price control will be published in September.

Main proposals

The initial proposals represent an important milestone in the review process. They set out, for the first time, Ofgem's views on the costs that companies are likely to incur over the next price control period. The key theme for the review is reflected in three main areas:

- **incentives for investment and efficiency –** at this review, some of the companies have forecast significant increases in investment - others less so. Across all companies an increase of over 40 per cent from current levels is sought. Ofgem's task has been to assess and challenge companies' plans and to ensure that the incentives provided to companies are appropriate.

  Where forecasts have been fully justified, and appear to represent a realistic level of expenditure, they have been accepted. However, other companies have not provided convincing arguments to support all of the increases they are seeking. As a result, significant adjustments have been made to some companies' plans. After these adjustments, the initial proposals still envisage investment rising over the next price control period by around 30 per cent.

Protection of consumers' interests requires that companies have incentives that encourage them to invest efficiently. Those incentives need to be balanced against a need to ensure that investment does actually take place to deliver the outputs that are required.

Where companies' forecasts are less well justified, there is a greater risk that underspend is due to forecast error rather than efficiency, or that the company will need to spend more money than it has been able to justify. Ofgem is therefore proposing a sliding scale mechanism which would allow such companies to spend more than they have justified but receive lower returns for underspending. At the same time, companies submitting convincingly argued forecasts will be rewarded with a higher rate of return and a stronger incentive for efficiency.

Companies have achieved significant efficiency savings over the period of the existing price control. Whilst the benefits of these savings will be shared with consumers over the next price control period, companies should continue to seek further efficiencies. Companies have been given incentives that will allow them to benefit if they manage to exceed the cost targets set by Ofgem. These targets, which have been informed by comparative analysis, are expected to be stretching for some companies but achievable;

- **quality of service –** consumers value quality and security of service as well as the price that they pay. Work on assessing consumers' priorities suggests that they are willing to pay more for improved service – but only up to a certain point. The existing quality of service incentive scheme has provided real benefits to consumers with improvements in performance of around 7% since it was introduced in 2001/02. Ofgem has examined both the scope for higher quality of service and the costs of achieving it. This suggests that further improvements of around 12% against 2003/04 levels can be achieved over the period to 2010 without imposing substantial additional costs on consumers. Ofgem has strengthened the incentives that companies have to meet, or exceed, these targets. Incentives are also set out to help ensure that the speed and quality of telephone response provided to consumers when they contact companies remains of a high standard.

Experience from the October 2002 storms showed that changes were needed to strengthen the incentives that companies have to restore supply as quickly and efficiently as possible following severe weather events and to streamline the arrangements for providing compensation to consumers affected. The initial proposals incorporate these improvements; and

- **responding to the challenge raised by growth in renewable energy -** Generators and industry commentators have argued that the existing charging arrangements for connecting to the distribution networks have created barriers to entry. Revised connection charging arrangements should address these barriers.[3] Ofgem has also examined the way DNOs respond to requests from generators to connect to their network. New incentive arrangements were proposed in March[4] for DNOs to respond proactively to such requests. Ofgem believes that these arrangements will remove unnecessary regulatory obstacles to the achievement of the Government's targets for renewable energy.

Implications for distribution charges

Meeting the challenges that the sector faces will involve increased costs, especially those relating to investment. There are also outside pressures on costs, particularly in the case of pensions, business rates and taxation. Such factors are placing upward pressure on charges.

Companies have however already achieved significant efficiency savings during the present price control period and these are now being shared with consumers. Future targets that incorporate some further improvement in efficiency are also proposed.

Providing consumers with value for money does not mean that charges should fall in all cases. The initial proposals suggest that, for most companies, further reductions in charges can be achieved together with the necessary improvements in service. For others, however, charges may increase. Details on the factors driving the changes in charges are set out in Chapter 8 for each company.

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[3] Structure of distribution charges; update and licence modifications", Ofgem 76/04, April 2004.
[4] Electricity Distribution Price Control Review, Policy document, Ofgem, March 2004.

Table 1 shows the changes in distribution charges implied by the initial proposals. It is in the form of an initial adjustment (or 'P0' change) in 2005/06. Charges would then be allowed to rise by no more than the rate of inflation less 1 per cent (i.e. RPI-1) in subsequent years. The initial proposals are based on a cost of capital at the mid-point proposed in the March 2004 document (i.e. at 6.6 per cent on a pre-tax basis).

Further work will now be undertaken to refine the cost assessments and financial analysis that underlies the initial proposals. This will include work to confirm that the proposals should allow the companies to retain a credit rating that is comfortably within investment grade. Ofgem's current expectation is that this further work will, in most cases, lead to final proposals in November within a few percentage points of the figures set out in Table 1.

Distribution charges account for around 30 per cent of consumers' final bills so the changes in final prices that may arise would be significantly less than the figures in Table 1.

Table 1: Initial proposals for changes in distribution charges

DNO	P0 change in 2005/06 (per cent)
CN – Midlands	-6
CN – East Midlands	-11
United Utilities	-2
CE – NEDL	-11
CE – YEDL	-15
WPD – South West	0
WPD – South Wales	+2
EDF – LPN	-2
EDF – SPN	-4
EDF – EPN	-5
SP Distribution	+8
SP Manweb	+4
SSE – Hydro[1]	0
SSE – Southern	+6
Average	**-2**

Notes: (1) The P0 calculation reflects the proposed change in price control revenue. This is not affected by the end of Hydro - Benefit, although in the absence of any other subsidy (see Chapter 3), costs recoverable from consumers would rise by approximately 30 per cent.

Interpretation of the P0 changes needs care. The differences in P0 changes across companies are not due solely or mainly to differences in efficiency.

After the effect of these P0 changes, the intention is that all companies will earn the same baseline return (6.6 per cent pre-tax real) if they perform in line with Ofgem's cost projections plus:

- the quality of supply rewards for WPD;
- operating cost rewards for companies beating the upper quartile (primarily SSE-Southern); and
- capex incentive rewards for those companies that have best justified their forecasts.

If companies outperform the cost projections they will have the opportunity to earn a higher rate of return.

Table 2 shows a summary of the cost allowances underlying these initial proposals in comparison to current levels of expenditure.

Table 2: Comparison of cost allowances to current levels of expenditure

DNO	Capital expenditure		Operating costs
	Company's proposed increase over actual spend	Increase from actual spend to Ofgem's proposed allowance	Proposed allowance compared to actual 2002/03 expenditure
CN – Midlands	46%	43%	-14%
CN – East Midlands	49%	47%	-2%
United Utilities	32%	34%	-19%
CE – NEDL	4%	9%	5%
CE – YEDL	23%	21%	-1%
WPD – South West	3%	6%	-11%
WPD – South Wales	-14%	-14%	4%
EDF – LPN	90%	56%	-28%
EDF – SPN	66%	61%	-29%
EDF – EPN	79%	42%	-10%
SP Distribution	34%	25%	-10%
SP Manweb	63%	38%	-17%
SSE – Hydro	21%	14%	8%
SSE – Southern	30%	36%	13%
Total	42%	33%	-10%

Notes: (1) for capex, comparisons are on five year totals and actual means 2000-2003 out-turn figures and company projections for 2003-2005.
(2) for opex, comparisons are average 2005-2010 to actual 2002/03
(3) In all cases, costs are adjusted/normalised to be as comparable as possible – further details are in Chapter 6

Responding to the initial proposals

These are Ofgem's initial proposals and further work needs to be undertaken on refining the cost analysis and on finalising remaining policy issues before the update document in September and final proposals in November.

A key input will be the views of companies and other interested parties and formal responses to this document are invited by 9 August 2004.

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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 scope and nature of the work required to reset the price controls was explained in the first consultation paper on the review published in July 2003. The July 2003 document also set out the objectives for the review, which are primarily driven by Ofgem's statutory objectives and duties and the statutory and licence obligations of the DNOs.

1.2. Ofgem's principal objective as set out in the Electricity Act 1989 (as amended by the Utilities Act 2000) is to protect the interests of consumers, both present and future, wherever appropriate by promoting effective competition. The Electricity Act also sets out other important duties for Ofgem,[5] including:

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

1.3. Ofgem also has other environmental duties as set out in various other Acts.[6] Ofgem will have regard to all of its duties when carrying out its functions.

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

Project update

1.4. Ofgem published a paper in March 2004 setting out key policy decisions on the price control review. Since then, there have been a number of developments in the project including:

- sending DNOs an update on Ofgem's work on cost assessment in April;
- meetings with each of the companies to discuss the cost assessment work and outstanding policy issues;
- a public workshop on 20 April to discuss key issues for the price control review. A number of DNOs, energywatch and City analysts gave presentations at this event;[7] and
- the completion of a survey undertaken on behalf of Ofgem by Accent Marketing and Research (Accent) to assess consumers' priorities and their willingness to pay.

1.5. The Ofgem-DNO working groups have also met on a number of occasions to discuss key areas of the price control review.

Purpose and structure of this document

1.6. The work to review the distribution price controls has now reached an important milestone with the publication of these initial proposals. This document sets out Ofgem's initial view on the costs that companies are likely to incur over the next price control period and the impact this could have on distribution charges. It confirms the broad policy framework set out in the March document and sets out Ofgem's further thoughts in a number of important areas – particularly on incentives and quality of service. In certain areas, Ofgem would like to hear the views of respondents before reaching final decisions – these are clearly set out at the end of each Chapter.

[7] The slides used at the workshop are available on Ofgem's website.

1.7. Work will continue on refining the approach to the price control and in particular the analysis underlying the assessment of companies' costs and financial issues. Ofgem expects to publish an update document in September which will set out its further thinking on the price control, including revised estimates of the level of allowed revenue. The final proposals, which are due to be published in November, will set out Ofgem's decisions on the price control, which will then be proposed to the DNOs as licence modifications.

1.8. This document sets out the timetable and consultation process (Chapter 2) and is structured as follows:

- **the form and structure of the price control (Chapter 3)** – this Chapter confirms the broad policy framework set out in March and sets out Ofgem's further thoughts on electrical losses, dealing with uncertainty and the approach to metering;
- **quality of service and other outputs (Chapter 4)** – this Chapter sets out Ofgem's further thoughts on quality of service and in particular outlines targets for improvements in performance that companies will be expected to achieve by 2010. It also sets out incentives for telephone response and revised arrangements for severe weather;
- **distributed generation, the innovation funding incentive (IFI) and registered power zones (RPZs) (Chapter 5)** – this Chapter sets out some minor revisions to the IFI and RPZ arrangements;
- **assessing costs (Chapter 6)** – this Chapter outlines the work that Ofgem has undertaken on assessing companies' efficiency and costs;
- **financial issues (Chapter 7)** – this Chapter provides an update on financial issues including the financial indicators that have been used to assess the impact of the price controls on the DNOs;
- **setting price controls (Chapter 8)** – this Chapter explains how the price control calculations work and the key assumptions that have been used to derive the initial estimates of allowed revenue. It also provides a summary of the price control calculation for each company including an

explanation of the key factors that are driving changes in allowed revenue; and

- **further details on cost assessment (Appendix 1)** – this Appendix sets out further details on some of the adjustments underlying the work on cost assessment.

1.9. Ofgem has also published several supporting Appendices and documents:

1. a summary of responses to the March document including Ofgem's view on issues raised;[8]

2. the results of the consumer survey undertaken by Accent on consumers' priorities and willingness to pay;[9]

3. reporting and information requirements for the distributed generation incentive scheme and for IFI and RPZs;[10]

4. points of clarification and further detail about the operation of the incentive schemes for distributed generation, IFI and RPZ;[11]

5. the approach to developing licence modifications to implement the revised price controls including an initial draft of modifications for the distributed generation incentive scheme;[12]

6. the issues and questions for developing an overall Regulatory Impact Assessment (RIA) for the price control review and revised questions for developing the quality of service RIA;[13] and

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[8] "Electricity Distribution Price Control Review – Summary of responses to March policy document", Ofgem, June 2004.
[9] "Consumer expectations of Distribution Network Operators and willingness to pay for improvements in service", Accent Marketing and Research, June 2004.
[10] "Electricity Distribution Price Control Review – Regulatory instructions and guidance for distributed generation, innovation funding incentive and registered power zones", Ofgem, June 2004.
[11] "Electricity Distribution Price Control Review – Further details on the incentive schemes for distributed generation, innovation funding and registered power zones", Ofgem, June 2004.
[12] "Electricity Distribution Price Control Review – structure and scope of price control licence modifications", Ofgem, June 2004.
[13] "Electricity Distribution Price Control Review – Developing Regulatory Impact Assessments", Ofgem, June 2004.

7. further details on the operation of the incentive mechanisms for electrical losses and on setting quality of service targets and storm arrangements.[14]

Responding to this document

1.10. 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.

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

1.12. Responses to this document and any of the separate Appendices and documents that Ofgem has published should be received by 9 August 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

[14] "Electricity Distribution Price Control Review – The losses incentive and quality of service", Ofgem, June 2004.

2. Timetable and consultation process

2.1. This Chapter sets out a slightly updated timetable for the price control review. There have been relatively few additions since the version published in the Mach document. Ofgem has decided not to hold the workshop previously scheduled for 1 July.

2.1. Of the output milestones set out in the March document for the period March to end June, 6 were clear milestones for Ofgem and these were largely achieved on time although Ofgem did not publish a further version of the financial model and the consumer survey report was delayed due to additional analysis of the results being undertaken to inform the initial proposals.

2.2. Table 2.1 sets out the overall timetable for the review.

Table 2.1: Updated timetable for the price control review

Date	Output Milestone
June 2004	**Initial Proposals Paper published (including revenue allowances – P0/Xs)**
July 2004	Bilateral meetings with DNOs and other interested parties
August 2004	Review and incorporate 2003/04 out-turns (internal milestone) Responses received to June initial proposals (6 week response period)
September 2004	**Update Paper published (week commencing 20 Sept)**
October 2004	Bilateral meetings with DNOs and other interested parties Responses received from interested parties to update document (3 week response period)
November 2004	**Final Proposals Paper published (including P0/Xs/review of IIP and proposed Licence modifications)**
December 2004	Companies indicate whether they are willing to accept the new price controls
2005	
February 2005	Statutory notice on licence modifications
April 2005	**1 April New price controls implemented**
Early Summer 2005	Publish report on the price control review process for consultation
Autumn 2005	Publish final report on the price control review process

3. Form, structure and scope of revised price controls

Introduction

3.1. The March document set out Ofgem's proposals on a number of issues relating to the form, structure and scope of the price controls – although the views of respondents were sought on a few topics. This Chapter outlines Ofgem's further thinking in a number of areas and provides further details on the proposals, including:

- the treatment of business rates;
- the incentive rate and targets for electrical losses;
- the allocation of costs;
- dealing with uncertainty; and
- the approach to metering price controls.

3.2. The March document explained that the framework of incentive regulation (i.e. RPI-X) that applies to DNOs has worked well since privatisation. Costs have fallen and quality of service has improved. Over time, important developments have been made to the basic price control framework, including an increased focus on output regulation – particularly quality of service. RPI-X has served both consumers and companies well so far, and it will continue to do so, as long as the regulatory framework develops in response to the issues and challenges that emerge.

3.3. This review will introduce further developments to RPI-X including a new incentive scheme for connecting distributed generation efficiently and quickly and revised incentive arrangements for restoring consumers' supply following severe weather. It is also important that incentives to achieve efficiency savings and to deliver outputs are balanced – particularly at a time when investment will need to rise. Incentives provided to companies should not distort decisions or create opportunities to exploit the regulatory framework – for example, by reallocating costs between operating and capital expenditure.

3.4. A number of developments have already been proposed, or are set out in this document, to address these aims.

Form of the price control

Revenue driver

3.5. The March document proposed inclusion of charges to existing consumers connected at Extra High Voltage (EHV) within the scope of the price control and that as a result the weightings on the existing revenue driver would be reviewed.

3.6. Discussions with DNOs and analysis of information that has been submitted shows that the majority of costs associated with the provision of EHV services are sunk in the initial connection cost. As a result, costs incurred by a DNO in relation to existing consumers are not driven by changes in the amount of EHV units distributed or capacity. **Ofgem proposes that for the next price control period there will be no volume driver attached to EHV revenues.**

3.7. Ofgem has also reviewed the weightings within the existing revenue driver. The manner in which the revenue driver operates means that it is important that the various volume categories are weighted appropriately relative to each other. There is some evidence to suggest that the relative costs of distributing units within the different unit categories has departed from the relative weights implied by the existing price controls. This suggests that some changes are appropriate to reduce the possibility of distorted incentives to encourage particular categories of units, especially at low voltages. **Table 3.1 sets out Ofgem's proposals on revised weightings applicable to each voltage category.**

Table 3.1: Revised weightings for the unit driver

DNO	LV1 (p/kWh)	LV2 (p/kWh)	LV3 (p/kWh)	HV (p/kWh)
CN – Midlands	1.0397	0.122	0.9286	0.2503
CN – East Midlands	0.7512	0.168	0.5537	0.196
United Utilities	1.1064	0.094	0.8219	0.17
CE – NEDL	1.0512	0.11	0.8205	0.158
CE – YEDL	0.77	0.12	0.6025	0.175
WPD – South West	1.88	0.41	1.2734	0.235
WPD – South Wales	1.86	0.27	1.3852	0.2415
EDF – LPN	1.097	0.136	0.6988	0.258
EDF – SPN	0.7456	0.0929	0.5076	0.2376
EDF – EPN	1.0252	0.301	0.9072	0.2503
SP Distribution	2.3041	0.2849	1.3996	0.215
SP Manweb	1.5005	0.2636	1.4931	0.135
SSE – Hydro	1.8824	0.8819	1.9542	0.49
SSE – Southern	1.2118	0.1806	1.0334	0.2842

LV1 is the weighting to be applied to units distributed to customers connected at low voltages during peak periods where the appropriate use of system charge apply different rates at peak and off peak times. **LV2** is the weighting to be applied to units distributed to customers connected at low voltages during off-peak periods where the appropriate use of system charge apply different rates at peak and off peak times. **LV3** is the weighting to be applied to all other units distributed to customers at low voltages where different rates do not apply to specified time periods. **HV** is the weighting to be applied to units distributed to customers connected at high voltages (greater than 1KV and up to 22kV).

Price index

3.8. The March document explained that the Treasury has changed the index used for setting the inflation target for the Monetary Policy Committee of the Bank of England from the Retail Price Index (RPI) to the Harmonised Index of Consumer Price (HICP) – which is known in the UK as the Consumer Price Index (CPI). This raised the question of whether the amount of revenue recovered through the price control should be uprated annually by CPI rather than by RPI as is currently the practice.

Views of respondents

3.9. Most respondents argued that RPI should continue to be used as it captures underlying changes of costs to which DNOs are exposed and it was the basis upon which DNOs submitted their forecast costs. It was also pointed out that retaining RPI would be consistent with the approach taken by other regulators.

Ofgem's proposal

3.10. **Ofgem proposes to use RPI for the next price control period.**

Scope of the price control

3.11. The March document largely confirmed the scope of the price controls although views were sought on a small number of issues.

Units distributed out of area

3.12. The March document raised the issue of how costs and revenue associated with networks that DNOs operate outside of their authorised area should be treated.

Views of respondents

3.13. Two DNOs and one other respondent considered that out of area networks should be subject to the same form of regulation as other licensed distributors, but one other DNO was strongly opposed to this proposal, considering that these networks are part of a competitive market and that the proposed extension of regulation would undermine competition in this area.

Ofgem's proposal

3.14. Although they may be some choice in the provision of out of area networks, once a company has provided the network it will be in a monopoly position and it is important that consumers are provided with protection from the possible abuse of these powers. **Ofgem proposes to impose a similar requirement on DNOs with respect of units distributed out of area as will apply to Independent Distribution Network Operators (IDNOs).** Under these arrangements, IDNOs will not be able to charge domestic consumers any more than the incumbent network operator. **Any revenue associated with distributing units out of area will be treated as an excluded service item.**

Non-contestable connection charges

3.15. The March document explained that Ofgem intends to develop standards of performance for new connections. Ofgem's initial thoughts in this area were set out in a document published earlier this month.[15]

Business rates

3.16. The March document explained that the Valuations Office Agency (VOA) and the Scottish Assessors Association (SAA) are in the process of establishing revised rateable values (RVs – which are analogous to taxable income) for all DNOs. Ofgem indicated that until it became clear whether DNOs have acted efficiently and appropriately in the current valuation process, it could not assess the appropriate treatment of these costs.

3.17. Since March, the DNOs have actively engaged with the VOA and the SAA in the valuation process and, in some cases, have secured significant reductions from the initial values proposed. **Subject to further review before final proposals, Ofgem is not currently proposing to disallow any rates costs.** Changes in the level of business rates and the impact on the price control are discussed in more detail in Chapters 6 and 8.

Hydro-benefit

3.18. Since the removal of Hydro-Benefit, the Secretary of State has proposed legislation[16] which would allow her to make an order to enable the Great Britain Transmission System Operator to provide a subsidy to a distributor with high costs by adjusting the transmission charges paid by all suppliers. Ofgem will set the price control to pass-through the benefit of any such subsidy to consumers – *no subsidy* is reflected in these initial proposals.

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[15] "Competition in connections to electricity distribution systems", Ofgem 124/04a.

[16] "Assistance for areas with high distribution costs" to be inserted in the Energy Bill after Clause 150 – proposed by the Lord Whitty (1 March 2004).

Revenue protection

3.19. Ofgem published a document on theft of electricity in April.[17] Ofgem is giving further consideration to the treatment of revenue protection costs – it may be appropriate to treat this function as an excluded service (i.e. outside the price control). **Views are welcome on this issue.**

Incentive framework

3.20. The March document outlined Ofgem's proposals for the cost incentive framework and sought views on a small number of issues:

- the allocation of costs between capital and operating expenditure for the incentive mechanisms;
- incentives for investment; and
- the treatment of any benefits received by DNOs from asset disposals between 1 April 2000 and 31 March 2003.

3.21. The issues surrounding asset disposals and incentives for investment are discussed in detail in Chapter 6.

Allocation of costs for the incentive mechanisms

3.22. The March document explained that the categorisation of costs as operating expenditure (opex) or capital expenditure (capex) varies substantially across DNOs and in some DNOs has changed over time – all, according to the companies, within the requirements of UK accounting standards. One reason for this is that the benefit that companies receive for reducing opex are greater than for a corresponding reduction in capex. There are currently no prescriptive definitions of capex and opex consistently adopted by all companies and it would take time to prove that any proposed definitions were effective. It was explained that one way of trying to overcome this issue would be to provide

[17] "Theft of electricity and gas – Discussion document", Ofgem, 85/04, April 2004.

more equal incentives where costs are close substitutes and where definitional boundaries are hard to set or enforce.

Views of respondents

3.23. The majority of DNOs that responded on this issue were not in favour of this proposal, with some highlighting that it affected the incentive properties of the entire price control framework and the ability of DNOs to outperform the control assumptions. Two DNOs suggested that it should be possible to classify costs in a more rigorous and prescriptive manner to overcome the perceived problem of inappropriate cost allocation.

Ofgem's proposal

3.24. Ofgem published a letter in May[18] on the equalisation of opex and capex incentives. This showed that distinctions between opex and capex (and hence incentives to capitalise) are an issue.

3.25. As work on the review has progressed it has become increasingly clear that the existing boundaries between capex and opex are not well defined and that the development of robust definitions is not achievable by final proposals in November. Ofgem recognises that the proposal to align opex and capex incentives will reduce, to some extent, the strength of opex efficiency incentives from the current level. However, as demonstrated in reports commissioned by Ofgem from Frontier Economics,[19] much of the strength of opex incentives is derived from the comparative assessment of efficiency at a price review, and this would not be affected. In Ofgem's view, it is not appropriate that DNOs continue to benefit, potentially at the expense of consumers, from unclear cost boundaries issues and from delivering "efficiency savings" by reclassifying costs.

3.26. **Ofgem proposes to treat all costs on the same basis for purpose of determining the incentive payment companies receive for achieving efficiency savings**, i.e. incentives for all categories of efficiency savings will be equalised. **This will be applied from April 2005.**

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[18] "Electricity Distribution Price Control – Equalisation of opex and capex incentives", Ofgem – May 2004.

3.27. Ofgem intends to work with the DNOs after the price control review to develop more robust reporting arrangements, including better definitions of cost categories. If it is clear that boundaries between opex and capex can be defined and enforced, Ofgem will review whether differential incentives (e.g. as have applied historically) are appropriate and whether incentives can be strengthened during the price control period.

Dealing with uncertainty

3.28. The March document explained that Ofgem did not favour the introduction of a formalised mechanism (like that used by Ofwat) to deal with new obligations and costs between reviews – but that it may be appropriate, in a limited number of instances, to provide some protection to DNOs.

Views of respondents

3.29. The DNOs submitted a joint letter on uncertainty through the Energy Networks Association (ENA) in April[20]. This set out their view of how a formalised mechanism for dealing with uncertainty could work. This proposed the introduction of two mechanisms – one for dealing with costs driven by new legal obligations and the other dealing with cost uncertainty associated with specific and identified issues.

Ofgem's proposal

3.30. Ofgem met with the ENA in May to discuss their proposal and it was pointed out that there were a number of difficulties with their approach. Although some of these difficulties could be overcome, Ofgem would prefer to put in place specific arrangements where there is cost uncertainty which has not been adequately dealt with under the price control.

3.31. There are two major areas where significant cost uncertainty is foreseen:

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[19] "Developing Network Monopoly Price Controls: Workstream B, Balancing Incentives", Frontier Economics, March 2003.
[20] The ENA paper is available on Ofgem's website.

- the introduction of the Traffic Management Act[21]; and

- changes to the Electricity Supply Quality and Continuity Regulations (ESQCR).

3.32. The Traffic Management Act is due to come into force around October this year. It is anticipated that the Act will include arrangements for reducing traffic congestion, including improving incentives for utility companies to reduce the amount of time spent on streetworks. It is not clear, at this stage, what the final arrangements will look like; what the financial impact on the DNOs could be; and how any costs that the companies incur should be treated. It is also unlikely that it will be possible to take full account of any scheme before final proposals for the price control review are published in November. There are a number of possible ways of dealing with this cost uncertainty but it is important to achieve an appropriate balance between maintaining incentives and providing companies with sufficient comfort that efficiently incurred costs will be remunerated.

3.33. One option would be to allow some form of pass-through of efficiently incurred costs for the first year of the price control and to assess the position after April 2005, when it becomes clearer what impact the Traffic Management Bill will have, including the way in which any costs should be treated going forward. Ofgem's preference would be to specify a fixed allowance for any costs as soon as the magnitude becomes clear and to allow DNOs to retain the benefits of efficiency savings consistent with the approach to cost incentives. **Ofgem's initial proposal is that a specific re-opener to the price control for the Traffic Management Act would be reflected in a relevant licence modification and that any costs would be considered in isolation from companies' financial performance under the price control.**

3.34. Similar considerations are relevant in relation to costs that DNOs may incur as a result of changes to the ESQCR. The Department of Trade and Industry (DTI) has indicated that it intends to consult on changes to the ESQCR around the end of this year. DNOs are also likely to incur some additional costs from 2008,

[21] The Traffic Management Bill was introduced in the House of Commons on 11 December 2003.

associated with clearances between buildings and overhead electricity lines where the clearances are between 2 and 3 metres, in accordance with a programme of work to be agreed with the DTI. **Ofgem's initial proposal is to use a limited re-opener following the consultation on changes to ESQCR at the end of this year and a further re-opener in 2008 to consider costs associated with line clearance work (i.e. a 2-stage specific re-opener), and that any costs would be considered in isolation from companies' financial performance under the price control.**

Losses

3.35. The March document set out a number of refinements to the way in which losses should be calculated and the way in which the existing incentive mechanism works. This built on the consultation paper on losses that was published in June 2003.[22] A summary of the key decisions that have already been taken in respect of losses are that:

- DNOs' performance on losses will be measured against a target that is fixed for the period of the price control;
- DNOs will be able to retain the benefits of loss reduction (or penalised for increases) for a fixed period of five years regardless of when the benefits (penalties) are realised; and
- losses will be measured as the difference between units entering and exiting the system in each DNO area.

3.36. This section sets out how the losses incentive has been derived. A separate paper published alongside this document provides further details on the operation of the incentive mechanism and the calculation of losses.

Valuing the incentive rate

3.37. In establishing revised incentive arrangements it is necessary to assign a value to the electricity that is lost during transportation. Electrical losses on distribution

[22] Electricity Distribution Losses: Initial Proposals", Ofgem 44/03, June 2003.

systems impose a cost on society, both financial and environmental. This cost has four main components:

- the cost of purchasing lost units of electricity;
- the environmental cost of producing and transporting additional units of energy;
- the cost of using the transmission system to transport the additional units to distribution system entry points; and
- the cost of providing, operating, and maintaining additional distribution assets to transport the additional units.

3.38. Ofgem has looked at each of these components to establish a value for the incentive rate to apply from 1 April 2005.

Costs of purchasing lost units

3.39. There is no single approach to estimating the costs of purchasing lost units but where possible it should be based on market data. One approach would be to take information published on forward prices[23] for purchase contracts in the UK for delivery up to summer 2007 (i.e. a 2 year forward price). This would suggest a cost of around £27/MWh.

The environmental cost of losses

3.40. The requirement to produce additional units of electricity to meet those units lost during transportation has an impact on the environment. This largely relates to the extra emissions produced by power stations in replacing the units that have been lost. Deriving an estimate of the environmental cost of losses is not straightforward. The government has proposed a range for valuing the cost of carbon – the bottom end of which is £35/tC[24]. Using this figure produces an environmental cost of electrical losses of around £3.60/MWh. [25] The extent to

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[23] For example, from the European Electricity Argus
[24] Estimating the Social Cost of Carbon Emissions", Government Economic Service Working Paper 140.

which this figure should be added to the other components of costs is open to question, as:

- a proportion of the environmental cost will already be reflected in forward purchase costs as the market's expectation of the cost of carbon emission allowances. Current emission trading prices suggest that this value could be of the order of £1.80/MWh – although it is difficult to assess whether the cost of carbon emission allowances is fully priced in by the market; and
- the extent to which the £3.60 reflects actual future environmental costs is uncertain. The estimate is based on the lower end of the government's range for the cost of carbon – which is in the process of being reviewed. The extent that environmental costs will be incorporated in the purchase price of electricity is expected to change once the European Union Emissions Trading Scheme moves into its second phase after 1 January 2008. This could lead to higher estimates of environmental costs, the impact of which would not be reflected in an estimate of purchase costs up to Summer 2007.

3.41. Given these uncertainties, Ofgem has considered the cost of purchasing lost units and the associated environmental costs together. To reflect the longer-term pressures, the value used in deriving the losses incentive rate has been increased from the two-year market price of £27/MWh to a figure of £30/MWh.

Transmission costs

3.42. The transmission costs of distribution losses have been derived by estimating the contribution of distribution losses to demand on the transmission system at peak periods. This contribution has then been valued relative to current transmission charges. This yields a transmission cost relating to a lost unit of electricity of between £1 and £4/MWh.

Distribution costs

3.43. The majority of distribution revenues reflect the costs of providing and maintaining distribution assets to accommodate peak demands, including the capacity utilised by lost units. At times of system peak demand, approximately 1

MWh of electricity is lost in transporting 4 MWh of energy. This means that around 20 per cent of capacity is utilised by lost units of electricity. The distribution costs have been estimated as the costs of providing this additional capacity for losses. This suggests a distribution cost of between £10 and £21/MWh.

Overall incentive rate

3.44. Bringing these costs together would suggest that the incentive rate for losses should be in the range £41/MWh to £55/MWh. This represents a significant increase from the existing incentive of around £30/MWh. Given the uncertainty surrounding the various elements of costs **Ofgem proposes to use the mid-point of this range, i.e. £48/MWh (in 2004/05 prices), for the duration of the price control. Views are welcomed on this issue.**

Targets for losses

3.45. The June 2003 document on losses set out the basis upon which targets will be calculated. In brief, this rolls forward individually for each DNO the 10 year average of actual losses which are the basis of the current losses target. Table 3.2 sets out Ofgem's initial view based on the latest available data – further details are in the supporting paper on losses. Once outturn data is available for 2003/04 (in September) it will be possible to set final targets for the next price control period.

Table 3.2: Fixed losses target

DNO	Losses target (% units distributed per annum)
CN – Midlands	5.0
CN – East Midlands	5.8
United Utilities	5.4
CE – NEDL	5.3
CE – YEDL	5.9
WPD – South West	7.0
WPD – South Wales	4.9
EDF – LPN	6.7
EDF – SPN	6.6
EDF – EPN	6.5
SP Distribution	6.5
SP Manweb	7.3
SSE – Hydro	8.6
SSE – Southern	6.7
Average	6.2

Metering

3.46. Effective competition provides the best protection to consumers. Ofgem has sought to secure effective competition in the provision of meters and metering services by addressing many of the barriers that previously existed. The changes proposed in relation to metering in this document are designed to further facilitate Ofgem's policies towards metering.

3.47. In July 2003, because of the potential distortion resulting from a single price control covering both metering and distribution, Ofgem indicated that separate price controls for metering would be introduced for DNOs from 1 April 2005. In addition, separation of metering and distribution price controls is necessary to facilitate sale of DNOs' metering businesses as discussed in Ofgem's sale of metering businesses document[26].

3.48. As DNOs currently have close to 100% share of their "in area" metering market, the introduction of competition will lead to DNOs losing business within their

[26] Ofgem (October 2000), Sales of metering business of Public Electricity Suppliers, Decision document.

distribution services area, although individual DNOs (or their corporate groups) could gain new business out of area.

3.49. Ofgem also announced that it will use depreciated replacement cost to value metering assets, with current "out of market" asset costs being recovered through monopoly distribution charges.

Structure of control

Meter Asset Provision (MAP)

3.50. MAP is the service of providing metering assets - it does not include other aspects of metering such as installation and maintenance. **Ofgem is proposing a price cap for the provision of certain types of meters and a licence condition requiring the DNOs to use a non-discriminatory approach to calculate price capped and non-price capped charges** in relation to meters provided in accordance with standard licence conditions 36-36C of the distribution licence. The MAP price caps will not vary with the quantity of meters provided.

Meter Operation (MOp)

3.51. MOp is the service that involves all work carried out on meters apart from their provision, and apart from meter reading, which has never been a DNO function.

3.52. **Ofgem is proposing an average revenue cap where the revenues derived from providing meter operation services in accordance with standard licence conditions 36-36C of the distribution licence are limited by an amount related to the number of meters provided.** The relationship will be defined to give the DNOs increasing revenue per meter point as they lose market share. This is a transitional approach to allow the DNOs to recover the short term fixed costs of metering activities as they move into the competitive environment.

3.53. Ofgem welcomes views on whether DNOs should recover the fixed costs associated with lost market share through their remaining MOp market share.

Indicative numbers

MAP

3.54. There will be two price caps for meter asset provision. These are summarised in Table 3.3 which shows an indicative range in which the price caps will lie.

Table 3.3: Indicative range for MAP price caps

DNO	Domestic Credit (£/meter)		Prepayment (£/meter)	
	Current Charge	Proposed Range	Current Charge	Proposed Range
CN – Midlands	1.35	0.85 – 1.00	7.33	6.99 – 8.94
CN – East Midlands	1.10	0.72 – 0.88	9.31	6.40 – 8.37
United Utilities	1.64	0.96 – 1.49	13.36	8.55 – 12.65
CE – NEDL	1.35	0.84 – 0.91	10.04	7.58 – 9.13
CE – YEDL	1.86	0.82 – 0.89	9.71	7.12 – 8.65
WPD – South West	1.13	0.77 – 0.89	6.97	8.67 – 10.82
WPD – South Wales	1.13	0.82 – 1.00	6.72	8.63 – 10.99
EDF – LPN	1.00	0.71 – 0.78	9.67	7.38 – 8.96
EDF – SPN	1.97	0.76 – 0.86	10.44	7.87 – 9.67
EDF – EPN	1.49	0.68 – 0.75	10.73	8.38 – 9.98
SP Distribution	2.56	0.87 – 1.23	2.56	7.75 – 10.97
SP Manweb	2.56	0.86 – 1.27	15.00	8.17 – 11.88
SSE – Hydro	3.06	0.64 – 0.69	3.06	8.23 – 9.77
SSE – Southern	1.42	0.55 – 0.59	11.21	6.16 – 7.54

3.55. In a number of DNO areas the controlled price for PPM may well be higher than current charges as the controlled price is more closely related to the actual cost of provision. Ofgem has duties to have regard to the interests of a range of vulnerable consumers, and because PPM users include many of such consumers, it has considered carefully where the best interests of PPM users lie. In Ofgem's view the functionality of many PPM meters currently in use (in particular token meters) results in a lower quality service to prepayment consumers, and creates significant costs for suppliers in supporting these meters. It is in the longer-term interests of these consumers to see more modern meter types installed as these would improve customer experience and reduce other costs (e.g., servicing costs). In order to permit this new entry, it is important to avoid setting an artificially low price for meter assets through regulation.

3.56. It is possible that in the short term, removing this regulatory distortion may lead to higher DNO charges to suppliers for PPM meters. However, the DNOs will not be obliged to price up to the price controlled level, and in a context of growing competition will be mindful of the risk that higher charges might lead to a loss of market share. Moreover, even allowing for a higher meter charge, the lower cost to suppliers, as a result of innovation, in servicing these customers may mean that overall supplier charges to PPM consumers could be reduced over time.

3.57. Based on the range calculated and the current price charged by DNOs it is anticipated that the price charged by the DNO to the supplier for the provision of a single rate single phase domestic credit meter will fall as a result of the price control. This does not represent a reduction of the revenue for the DNO rather that the current charge reflects the historic cost of the meters whereas the MAP charge will be based on depreciated replacement cost. There is therefore a reallocation of costs between the metering and distribution price controls because the historic cost of meters is higher than the replacement cost.

3.58. The value of the price cap is based on adding together the annualised cost of the meter assets, plus any operating expenditure and the return on capital. This is then divided by the number of meters.

3.59. The annualised cost of the meter asset is determined by taking the value of the asset and dividing the total for each category of meter by the expected life of the asset. Meter operating expenditure is allocated to different meter types on a weighted average value basis. The cost of capital (assumed to be 6.6%) is applied to the depreciated replacement cost of the meter assets. The range in proposed price caps is explained by differences in the expected life of the asset and different treatment of operating costs.

3.60. The costs and asset prices used in calculating these price cap ranges are based on the costs and asset prices incurred by each individual DNO. These costs have not been standardised across the DNOs. It is Ofgem's view that, in the light of the relatively short term nature of the price controls, the provision of new meters does not require a separate efficiency analysis as developing competition will encourage the DNOs to price at competitive levels. **Ofgem welcomes the views in relation to this approach.**

MOp

3.61. The total metering opex and the number of meters for each DNO in 2002/03 is set out in Table 3.4.

Table 3.4: Total 2002/03 metering opex

DNO	Opex (£m)	Meter Numbers
CN – Midlands	5.1	2,442,000
CN – East Midlands	6.8	2,463,244
United Utilities	4.7	2,417,327
CE – NEDL	2.8	1,709,741
CE – YEDL	6.0	2,487,183
WPD – South West	5.4	1,500,583
WPD – South Wales	4.0	1,065,452
EDF – LPN	3.6	2,351,136
EDF – SPN	8.1	2,181,927
EDF – EPN	8.9	3,413,373
SP Distribution	3.3	1,994,387
SP Manweb	5.2	1,399,107
SSE – Hydro	2.7	793,496
SSE – Southern	6.3	2,799,197

3.62. The above figures for total metering opex need to be reviewed in order to determine the appropriate allowance for MOp costs and hence the level of revenue. The review needs to consider what services are included in MOp e.g. installation costs (which are not included in Table 3.4), overhead allocations and margins. Ofgem is working with the DNOs to review these costs.

3.63. In addition, where appropriate, a mark up in relation to this activity may be included as assets are only a small part of the cost of MOp and consequently only allowing a rate of return on capital would lead to the DNOs making less than normal profit on this activity. This would risk excluding new entrants.

3.64. As the number of meters serviced falls then the associated revenue will fall by 60 to 80% of the revenue for that meter point. Ofgem will be working with the DNOs to ensure Ofgem has the information necessary to finalise this value before issuing final proposals on the metering aspects of the price control.

Associated changes – standard licence conditions 36-36C

3.65. Standard licence conditions 36-36C impose obligations on DNOs to provide metering services (both MAP and MOp). In a competitive market *obligations* on some participants to provide services would be an unnecessary (and possibly harmful) distortion. Ofgem is therefore proposing to modify these obligations in various ways with a view to removing them in the long term.

Basic services

3.66. Ofgem is proposing to change the obligation so that the DNOs are only obliged to provide "basic" metering services. Ofgem is proposing to define "basic" meters (for MAP) as meters with the same functionality as the meters provided to discharge the obligations under Standard Licence Conditions 36-36C of the distribution licence as at 1 April 2003. "Basic" services (for MOp) will be defined as service of a quality that would have been provided to discharge the obligations under Standard Licence Conditions 36-36C of the distribution licence as at 1 April 2003.

3.67. This date is convenient as it was sufficiently before the price control review process started to ensure that DNOs could not have manipulated the nature of this obligation by modifying the services they provided.

3.68. This approach guarantees that the *status quo* quality of service will be available at the price-controlled prices but allows DNOs and suppliers to contract freely between themselves for different qualities of service at different prices.

3.69. Ofgem invites the views of interested parties on the proposed approach to defining a basic meter and basic service.

One way door

3.70. Ofgem is proposing to modify the obligation to provide metering service so that it does not apply to suppliers in relation to meter points at which they have decided to take services from metering service providers other than the DNO. This maintains the obligation on DNOs to provide services for new entrant suppliers and those suppliers who currently need the service but removes the requirement for DNOs to maintain the capacity and ability to serve the entire market.

Long term switch off

3.71. To the extent that the provisions of SLC 36-36C relate to meter operation and the provision of new metering assets, Ofgem is proposing to switch off these provisions with effect from 1 April 2007. This gives clarity about the timetable for deregulation and gives sufficient notice to electricity suppliers to allow them to engage with the competitive metering market and ensure they can obtain metering services after the disapplication of the licence conditions. However Ofgem is not, at this stage, going to commit to removing obligations in relation to assets already provided as potentially the economics of these assets means DNOs will retain some residual market power for a significant length of time.

3.72. These proposals provide backstop protection to the purchasers of metering services (suppliers) whilst creating a strong movement in the direction of a competitive metering market. Consequently they will achieve Ofgem's objective of protecting customer interests in the short term by explicit controls over pricing and in the long term by promoting effective competition in electricity metering services.

Summary

3.73. Table 3.5 provides a summary of Ofgem's position on the form, structure and scope of the price controls. Most issues are now resolved although views are invited on a small number of issues.

Table 3.5: Scope and form of price control and incentives – summary of Ofgem's position

Issue	**Proposal**	**Further consideration**
Duration	5 years	
Inflation measure	RPI	
NGC Exit charges	Pass-through	
Business rates	Pass-through, subject to further review of final rateable values	
EHV charges	Include in price control	
Revenue driver	Retain 50:50 split Use actual consumer numbers Zero weighting on EHV Revised weightings for other voltages	
Losses	Simplify mechanism - remove all adjustments except modified generation adjustment 5 year rolling incentive Incentive rate of £48/MWh	Losses target taking account of 2003/04 outturn performance
Uncertainty	No general mechanisms for dealing with uncertainty	Specific form of re-opener for 'lane rentals' and ESQCR costs
Cost categorisation	Equalise opex and capex incentives Develop cost categorisation immediately after price review concluded	
Strength of incentives	5 year rolling retention mechanism Introduction of sliding scale mechanism for investment incentives (see Chapter 6)	Detail mechanics of the sliding scale mechanism
Metering	Separate from distribution price control	Indicative price controls/allowances

Views invited

3.74. Views are particularly invited on:

- the losses incentive rate and targets; and
- the approach to metering price controls including the indicative price controls and allowances.

4. Quality of service and other outputs

Introduction

4.1. Ofgem's initial thoughts on the quality of service incentive arrangements were set out in the March document. Since then, the second stage of the consumer research has been completed and further work has been undertaken, using 2002/3 and 2003/4 data, on benchmarking quality of supply performance.

4.2. This Chapter sets out a summary of the results of the consumer research and Ofgem's initial proposals for each of the main areas of the quality of service arrangements including:

- changes to Guaranteed Standards of Performance;
- targets and incentive rates for the number and duration of interruptions to supply;
- incentives for restoration following severe weather events;
- incentives on the quality of telephone response provided by DNOs;
- environmental reporting; and
- a discretionary reward scheme.

Summary of results from the consumer survey

4.3. The second phase of Accent consumer research has focused on gaining a better understanding of consumers' priorities and their willingness to pay for quality of service improvements.

4.4. The research, which covered all 14 distribution service areas, comprised 2118 face-to-face interviews with domestic consumers, and 1965 telephone interviews with business consumers. The main findings of the research include that:

- there is low awareness of current service standards;

- both domestic and business consumers have high expectations in terms of quality of service;
- consumers expect rapid restoration of power, even after a major storm;
- consumers are prepared to pay a significant amount for reductions in frequency of power cuts, but only in their own area;
- improvements in network resilience are valued by some consumers but not others;
- a step change in resilience, such as major power cuts being reduced to once every five years rather than once a year, would be valued by all consumers *but less so* than improving restoration times;
- consumers are prepared to pay for reductions in the duration of power cuts; and
- domestic consumers would be willing to pay more on their bill to ensure that they receive accurate information during a power cut.

4.5. The results of the survey provide important information on consumers' priorities. The scale of the willingness to pay indicated by the survey is, in some cases, very high in comparison to other studies that have been undertaken in the UK and abroad.[27] This casts some doubt on the results of the survey. As with any other survey, the results are affected by the design of the survey and by how the questions and context of the survey are perceived. The results are inevitably indicative and not definitive.

4.6. The results do point towards a degree of willingness to pay which could be reflected in stronger incentives for improvements in quality of supply, provision of information and restoration of supplies following severe weather events.

[27] The CIGRE report on " Methods to consider customer interruption costs in power systems analysis", June 2001, provides a comprehensive literature review on studies of the costs of interruptions carried out in both the UK and in other countries.

Revenue exposure to quality of service incentives

4.7. Quality of service incentives have become widely accepted by companies – senior management has a stronger focus on quality of service, both in terms of day to day management of the network and also in longer term investment decisions.

4.8. Together with the survey results and other evidence of consumers' priorities, this suggests that the previous cap on the level of revenue exposed to quality of service performance should be increased, i.e. incentives should be strengthened. **Table 4.1 sets out Ofgem's proposals for the amount of revenue to expose to quality of service.** There are some 'new' areas where companies will be incentivised – the details of these mechanisms are explained below.

Table 4.1: Revenue exposure to quality of service

Incentive arrangement	Current	Proposal
Interruption incentive scheme	+2% to -1.75%	+/- 3%
Storm compensation arrangements	- 1%	- 2%
Other standards of performance	Uncapped	Uncapped
Quality of telephone response	+/- 0.125%	+0.05% to –0.25%
Quality of telephone response in storm conditions	Not applicable	0 initially +/-0.25% for 3 yrs
Discretionary reward scheme	Not applicable	Up to +£1m
Overall cap/total[28]	+2% to –2.875%	4% on downside No overall cap on upside

Standards of Performance

4.9. The March document consulted on changes to the existing framework of Guaranteed and Overall Standards of Performance (GOSPs) and in particular:

- the severe weather arrangements;
- semi-automatic compensation payments;

- the route for making payments to consumers;
- compensation for High Voltage connected business consumers; and
- removal of the overall standards (OSs).

Views of respondents

Severe weather standard

4.10. Most respondents supported the principle of dividing the supply restoration standard into two separate standards covering normal and severe weather events. Two DNOs had concerns with Ofgem's proposed approach for revising the interim arrangements.

Semi-automatic payments

4.11. Four DNOs supported the concept of semi-automatic payments for supply restoration (i.e. paying consumers automatically where possible and in other circumstances making consumers aware of their rights to compensation), but thought this was only feasible during normal weather conditions. Some DNOs noted that semi-automatic payments would result in additional costs, even for efficiently operated companies, and therefore indicated that an efficient level of payments should be funded through the price control.

4.12. DNOs generally opposed the introduction of a mechanism that imposes equal penalties on companies for a failure under the 18 hours standard or severe weather arrangements, regardless of whether or not a consumer claims.

Route for payments to customers

4.13. Under the current framework, DNOs are required to make payments to consumers via suppliers. The majority of DNOs are concerned that this results in delays in payments reaching consumers.

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

Compensation for HV connected business consumers

4.14. There was broad consensus among DNOs that large commercial consumers connected to the high voltage networks have the ability to choose the degree of security of supply in their connection arrangements, and therefore have an opportunity to mitigate the risk of supply interruptions through these agreements. DNOs generally considered that it was inappropriate to make large payments to HV consumers who have chosen less secure connection arrangements. Two respondents felt that the compensation regime should be more closely related to charges.

The role of the overall standards of performance

4.15. Respondents generally supported the proposal to discontinue the overall standards and, where appropriate, introduce similar measures to be reported under the Regulatory Instructions and Guidance (RIGs).

Ofgem's proposals

Severe weather standard

4.16. There will be separate standards for restoration under "normal weather" conditions and severe weather set out in a new licence condition (see section on storm payment arrangements). The existing 18-hour threshold and levels of compensation will be retained under normal weather conditions.

Semi-automatic payments

4.17. The March document explained that DNOs should pay out automatically under the standards, where possible, and be more proactive in contacting consumers in general to make them aware of their right to compensation. The consumer survey indicates some degree of willingness to pay for all the standards being automatic.

4.18. The consumer research results indicate there is very low awareness of the standards of performance. Companies have an incentive to avoid making consumers aware that they are entitled to a payment for a failure. Ofgem's view is that this incentive should be removed by ensuring that the penalty to companies, where there is a failure under the 18 hour restoration standard or severe weather arrangements, is the same, whether or not the consumer claims (i.e. where they do not pay the consumer the company will face an equivalent reduction in price control revenue). Proposals for allowances to cover efficient costs are set out below.

Route for payments to consumers

4.19. Ofgem considers that the current mechanism for making payments to consumers via suppliers may result in additional administration costs and delays in payments reaching consumers. This is not in consumers' best interest. **Ofgem proposes that DNOs should have the option of making payments directly to consumers, although there should still be the alternative of making payments via suppliers where this is not practicable.** This will also bring the arrangements in electricity distribution in line with those for gas distribution.

Compensation for HV connected business consumers

4.20. The results of the survey suggest that large business consumers are not interested in small increases in standards of performance payments because they regard current levels as insignificant.

4.21. Increases in payments for business consumers would need to be funded either from the generality of consumers or business consumers as a class. The first option would imply a cross-subsidy between domestic and business consumers. As regards the second option, business consumers indicated that they were not willing to pay for increased compensation. Further, such consumers will typically be able to choose the degree of security of their connection, or to purchase standby generation or insurance to cover their losses. **Ofgem proposes to retain the existing arrangements.**

Overall standards of performance

4.22. Ofgem proposes to remove the Overall Standards on DNOs from 1 April 2005. Where appropriate, these will be replaced by similar reporting requirements under the RIGs. A revised draft of version 5 of the RIGs will be published for consultation in July.

Interruptions incentive scheme

4.23. The March document consulted on changes to the framework of the interruptions incentive scheme introduced under the Information and Incentives Project (IIP) in 2002 – particularly on:

- the form of incentive scheme including the weighting of planned interruptions;
- target setting;
- audits and adjusting data for inaccuracy; and
- frontier performance.

Views of respondents

Form of the incentive scheme including the treatment of planned interruptions

4.24. There was general support for Ofgem's proposal to move to a scheme with annual rewards and penalties with no deadbands or rolling averages. DNOs consider that the rewards and penalties should be symmetric with the full impact of exceptional events excluded.

4.25. The DNOs were concerned about the proposal to introduce different weighting for planned and unplanned interruptions as it may provide distort incentives to use the most efficient approach for improving consumer service.

Target setting

4.26. Two DNOs indicated that the method used for comparing performance at circuit level is not robust enough to generate targets as it does not capture all of the inherent and inherited differences between networks.

4.27. Another DNO noted that the targets will need to take into account increases in planned interruptions to undertake more asset replacement in the next price control period.

Audits and adjusting data for inaccuracy

4.28. The majority of respondents were in favour of maintaining a streamlined version of the existing audit process, at least in the short-term. Some felt that it was appropriate to move to self-audit, followed by Ofgem carrying out annual audits of a randomly selected sub-sample of incidents.

4.29. DNOs were generally against adjusting reported performance to take into account any inaccuracies identified by the audits. One DNO proposed adjusting data that is less than 95% accurate overall (or 90% accurate at LV) to the average level of accuracy of data that is in line with the accuracy requirements.

Frontier performance

4.30. Three DNOs supported the proposal to modify the rules of the 2004/05 incentive mechanism to allow frontier performing companies to participate in the outperformance mechanism whether or not they achieve both their CI and CML targets. One of these felt that the best performing companies should be identified by comparing each company's actual performance with their benchmarked performance and then ranking their relative performance.

4.31. One DNO was strongly against this additional reward as they viewed it as a re-opener of the current price control.

Ofgem's proposals

Form of the incentive scheme including the weighting of planned interruptions

4.32. Setting targets for quality has become more robust as information on and understanding of quality performance has improved. Ofgem is in a better position to set targets that are more equally challenging across companies and as such it is appropriate that DNOs have the opportunity to earn additional revenue if they perform well. **Ofgem proposes an incentive scheme for interruptions with symmetric annual rewards and penalties depending on performance against their targets. The impact of severe weather event will be fully excluded from the scheme** (definitions and separate incentives in this area are outlined below).

4.33. Consumers have indicated that they value reductions in the average duration of interruptions more highly than reductions in the actual number experienced. DNOs also have more control, at least in the short term, over the duration of interruptions. On this basis, **Ofgem proposes to increase the revenue exposed to 1.2 per cent on the number of customers interrupted (CI) and 1.8 per cent on the number of minutes lost per customer (CML).**

4.34. The results of the survey suggest that planned interruptions are approximately half as disruptive to consumers as unplanned interruptions. **Ofgem therefore proposes applying a 50 per cent weighting to these outages within the interruptions incentive scheme.** Given the increase in exposure for the incentive scheme as a whole, the reduction in absolute incentives to reduce planned interruptions and planned minutes lost will be relatively small. Further, rather than distorting incentives, a reduction in the relative weighting on planned interruptions ensures that incentives are more closely aligned with consumers' preferences.

Setting targets - number of interruptions

4.35. Ofgem has updated its circuit level benchmarking analysis using both 2002/3 and 2003/4 performance data. This has been used to establish benchmarks and targets for performance.

4.36. As part of the Forecast Business Plan Questionnaire (FBPQ), Ofgem asked DNOs to provide detailed information on the work required to achieve various quality of supply improvements and the associated marginal costs. Ofgem has met each of the DNOs to discuss these forecasts.

4.37. To set targets, Ofgem has derived benchmarks for the number of interruptions experienced by customers based on average performance at a disaggregated level across the companies and the make-up of each network. **Ofgem has applied a 0.5% per annum improvement in the benchmarks for the number of customers interrupted through to 2020 to reflect developments in technology and best practice.**

4.38. **If a company is already outperforming the 2020 benchmark calculated on this basis the proposed targets are set in line with current performance. If a**

company's average performance is worse than its 2020 benchmark the proposed targets are set based on catch-up of 40 per cent of the performance gap by 2010, provided that the improvements can be achieved at reasonable cost.

4.39. All companies that are required to make improvements in the number of interruptions experienced by consumers have been given an associated capital expenditure allowance based on an assessment of the marginal costs of improvement. Where the costs appear disproportionate, the required rate of improvement in customer interruptions has been reduced.[29]

Setting targets - duration of interruptions

4.40. Ofgem has calculated benchmarks for average restoration times 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.

4.41. **Ofgem proposes to apply these benchmarks to the targeted number of interruptions to derive the 2010 targets for customer minutes lost.**

4.42. Ofgem also intends to include a cost allowance for operational improvements to enable companies to reduce average restoration times. This allowance is based on a specified amount per fault (just over £200)[30] multiplied by a benchmark level of faults for each company.

Summary of targets and associated cost allowances

4.43. Tables 4.2 and 4.3 set out DNOs' historic performance, the proposed 2010 targets and associated cost allowances, and the current IIP targets. All the interruption figures shown here have a 100 per cent weighting on planned interruptions for the purposes of comparison with the existing IIP incentive

[29] This applies to WPD South-West and Southern, where further improvements to close more of the gap to the 2020 benchmarks are costly relative to other companies. This is largely due to the more expensive types of work involved such as refurbishment of lines.
[30] Based on information provided by one of the DNOs.

scheme. The accompanying paper on losses and quality of service sets out the targets with the proposed 50 per cent weighting on planned interruptions and minutes lost, along with the profiles to give annual targets.

4.44. Tables 4.2 and 4.3 show that, on average in 2003/04, companies were already outperforming their 2004/05 IIP targets for the number and duration of interruptions by 10 and 12 per cent respectively. They also show that, on average, the proposed 2010 targets for the number and duration of interruptions are 10 and 20 per cent tighter than the 2004/05 targets.

Table 4.2: Targets and cost allowances for the number of customers interrupted (CI)

DNOs	Actual				Improvement	Target	IIP target	Capex (5 yrs)
	01/02	02/03	03/04	Average	CIs	2010	04/05	£m
CN - Midlands	124	102	116	114	8	106	131	22
CN - East Midlands	79	84	86	83	2	81	81	17
United Utilities	56	66	50	57	0	57	55	0
CE - NEDL	84	79	68	77	1	76	90	0
CE - YEDL	78	63	66	69	1	68	85	4
WPD - South West	104	86	74	88	0	88	81	0
WPD - South Wales	121	105	99	108	6	102	153	6
EDF – LPN	39	36	32	36	0	36	32	0
EDF – SPN	94	89	97	93	10	83	97	13
EDF – EPN	102	92	93	96	8	87	92	13
SP Distribution	60	64	60	61	1	61	66	0
SP Manweb	47	41	51	46	0	46	47	0
SSE – Hydro	120	94	91	102	0	102	135	0
SSE – Southern	100	91	88	93	4	89	94	25
Average	85	78	77	80	3	76	85	7

Notes: (1) The annual performance figures shown year differ from the annual reported figures elsewhere as they are based on disaggregated performance figures with a different treatment for exceptional events. Unattributable incidents at HV are also currently excluded other than for the CN – Midlands for 2002/3. This will be given further consideration after initial proposals. (2) The targets shown here have a 100 per cent weighting on planned interruptions for the purposes of comparison with the existing IIP quality of service incentive scheme.

Table 4.3: Targets for the number of customer minutes lost (CML)

DNOs	Actual				Improvement	Target	IIP	Opex p.a.
	01/02	02/03	03/04	Average	CMLs	2010	04/05	£m
CN - Midlands	126	105	107	113	19	94	117	1
CN - East Midlands	93	101	89	94	20	74	71	1
United Utilities	64	67	58	63	11	52	68	1
CE - NEDL	88	73	70	77	9	68	97	1
CE - YEDL	73	67	73	71	9	62	67	1
WPD - South West	85	64	57	68	0	68	63	1
WPD - South Wales	92	87	76	85	0	85	129	1
EDF – LPN	42	43	38	41	1	40	45	1
EDF – SPN	97	81	89	89	22	66	85	1
EDF – EPN	80	83	82	82	10	72	82	2
SP Distribution	64	74	76	71	19	52	88	1
SP Manweb	53	53	64	57	12	44	66	1
SSE - Hydro	142	87	86	105	2	103	196	1
SSE - Southern	99	82	81	87	7	80	101	2
Average	83	77	76	79	11	67	85	1

Notes: (1) See notes to Table 4.2 above. (2) WPD South-West and WPD South-Wales' average performance is substantially below their benchmark levels for the duration of interruptions. Ofgem proposes to base their targets on their average performance rather than their benchmarks, effectively tightening their targets significantly. In return, Ofgem proposes to give WPD a revenue allowance equal to the difference between the benchmark and average performance multiplied by the incentive rate. (£1.5m per annum and £ 0.4 m per annum for WPD – South West and WPD - South Wales respectively. This relates to future performance targets and is separate from and additional to the reward for current best practice set out below).

Rewarding current best practice

4.45. Both WPD – South Wales and WPD – South West have achieved very good levels of performance in terms of average restoration times. This frontier performance is valuable in terms of revealing what might be possible at other companies. **Ofgem therefore proposes that WPD South West and WPD South Wales should be each given an additional reward of 1 per cent of revenue per annum** to reflect this achievement.

Setting incentive rates

4.46. Annual incentive rates needs to be established for both the number and duration of interruptions to supply. They specify the amount of revenue that DNOs will be rewarded (or penalised) for each 'unit' they beat (fail) a target. Ofgem has considered two approaches to setting the incentive rates:

- **a "bottom-up" approach** – the cost of an average interruption can be estimated from UK and other international evidence. This figure can then be used to calculate incentive rates, taking into account the number of consumers on each company's network and the proportion of revenue exposed to each output measure. This approach would result in variable performance bands; and

- **a "top-down" approach** – under this approach incentive rates are calculated by dividing the amount of revenue exposed to the output measure by common percentage performance bands.

4.47. Either of these proposals would ensure that companies with a larger consumer base, which need to deliver a larger reduction in the total number of interruptions or minutes lost for a given reduction in the per consumer number or duration of interruptions, receive larger incentive rates.

4.48. Ofgem proposes to use the incentive rates derived from the top-down approach. This has a number of advantages:

- it ensures that companies face a similar level of risk from underperforming or benefit from outperforming their targets by a given percentage. By contrast the "bottom-up" approach could result in a range of performance bands: for example, from 15 to 48 per cent either side of the targets; and

- it avoids the use of a subjective number for the cost/value of an interruption. There is a large range for the cost of interruptions from the available UK and international evidence.

4.49. For the purpose of these initial proposals and comparison with the existing IIP incentive scheme, Ofgem has calculated incentive rates using forecast 2004/5 base price control revenues. The 2009/10 incentive rates are set out in Table 4.4. The full profile of incentive rates are set out in the accompanying paper on losses and quality of service.

4.50. Ofgem is giving further consideration to the use of wider performance bands or deadbands where companies' performance shows high levels of volatility.

Table 4.4: Incentive rates for the number and duration of interruptions

DNO	Incentive rate for the number of customers interrupted per 100 customers (£m/CI)		Incentive rate for the number of customer minutes lost per customer (£m/CML)	
	2009/10 incentive rate	2004/5 IIP incentive rate	2009/10 incentive rate	2004/5 IIP incentive rate
CN - Midlands	0.11	0.06	0.16	0.10
CN - East Midlands	0.14	0.09	0.20	0.17
United Utilities	0.17	0.13	0.24	0.16
CE – NEDL	0.09	0.06	0.13	0.08
CE – YEDL	0.15	0.08	0.20	0.16
WPD - South West	0.09	0.07	0.16	0.13
WPD - South Wales	0.06	0.03	0.10	0.05
EDF – LPN	0.29	0.24	0.33	0.25
EDF – SPN	0.09	0.05	0.14	0.09
EDF – EPN	0.15	0.10	0.24	0.17
SP Distribution	0.20	0.13	0.30	0.14
SP Manweb	0.16	0.11	0.22	0.12
SSE - Hydro	0.08	0.04	0.10	0.04
SSE - Southern	0.16	0.11	0.23	0.15
Total	1.94	1.33	2.74	1.82
Average	0.14	0.09	0.20	0.13

Audits and adjusting data for inaccuracy

4.51. This year's audit of interruptions data and measurement systems has been streamlined compared to previous years. The audits are expected to take approximately 2 to 3 days rather than 5 days per DNO and Ofgem's audit costs have reduced significantly. It presently appears appropriate to continue with streamlined annual audits of each DNO, at least in the short-term, although Ofgem does not rule out moving to random audits (with adjustments being applied only where audits have occurred) in future.

4.52. **Ofgem proposes to adjust each DNO's data to take into account any inaccuracy identified by the audit.** Whilst the DNOs are correct in saying that the audit samples are only designed to reflect accuracy within certain confidence limits, with a symmetric incentive scheme the impact of any errors in the audit results will average out over time.

4.53. **Ofgem also proposes to tighten the overall accuracy requirements from 95 to 97 per cent over the next price control period.**

Frontier performance for this price control period

4.54. As discussed above, Ofgem has carried out further detailed benchmarking work using both the 2002/3 and 2003/4 data. Ofgem proposes to identify frontier performers by comparing each company's 3-year average performance (for 2001/2 to 2003/4) with their benchmarks for CI and CML/CI (based on both the 2002/3 and 2003/4 data). The companies will then be ranked on the basis of the performance relative to their benchmarks.

4.55. **Ofgem proposes that the top 4 performers on CI will be eligible to take part in the CI element of the outperformance scheme. The top 4 performers on CML/CI will be eligible to take part in the CML element of the outperformance scheme.**

Storm arrangements

4.56. The March document set out Ofgem's further thoughts on network resilience and the standard/incentives for restoration of consumers' supplies following a severe weather event.

Views of respondents

4.57. A number respondents felt that it would be better to define thresholds for the severe weather standard based on exceptionality (the number of faults) rather than materiality (number of consumers affected) as it is the number of faults that determines how long it will take to restore all consumers.

4.58. Some respondents felt that further work was needed to define an appropriate standard under severe weather conditions, and in particular to determine a fair combination of thresholds for different sizes of events, trigger periods for compensation and the levels of funding.

4.59. Several companies do not support enhancements to the existing interim storm compensation regime. They consider that public scrutiny, company reputation and the current level of exposure to the 'Interim Arrangements' already provide companies with strong incentives.

Ofgem's proposals

4.60. The interim arrangements introduced in November 2003[31] have not been fully tested, but initial reactions have been largely positive so **Ofgem proposes to retain similar arrangements for consumers for the next price control period.** Several key amendments are proposed below to strengthen and improve the existing arrangements:

- simplifying the "gates" for exceptionality so that they are based on the number of faults in a 24-hour period. This removes perverse incentives to increase the number of customers affected to qualify for the arrangements;
- introducing a shorter threshold for payments of 24 hours for "medium-sized" wind and snow events and all lightning events;
- revising the gate for "very large" severe weather events to 50 per cent of consumers on mixed or overhead circuits (i.e. those consumers that may be affected by a severe weather event); and
- raising the cap on the distribution companies' exposure to 2 per cent of price control revenue and removing the cost pass-through.

4.61. Further detail on the changes is set out in accompanying paper on losses and quality of service. They will strengthen the incentives on the DNOs and as a result Ofgem proposes to allow an annual cost allowance for exceptional events to cover an efficient level of compensation payments and fault costs relating to the events. DNOs will be free to use this allowance either to reduce the chance of such events occurring, to manage the impact of the event through faster customer restoration, or to buy storm insurance cover. The proposed opex allowances are set out in Table 4.5. Further detail on the calculation of these exceptional event allowances is set out in the accompanying paper.

Table 4.5: Exceptional event allowances

DNO	Annual allowance for exceptional events (£m)
CN - Midlands	£1.5m
CN - East Midlands	£1.3m
United Utilities	£0.9m
CE - NEDL	£1.9m
CE - YEDL	£0.5m
WPD - South West	£1.2m
WPD South - Wales	£2.3m
EDF - LPN	n/a
EDF - SPN	£0.7m
EDF - EPN	£1.9m
SP Distribution	£1.6m
SP Manweb	£1.2m
SSE - Hydro	£1.6m
SSE - Southern	£1.6m

4.62. As part of their business plan questionnaire (BPQ) responses, some DNOs put forward large expenditure plans for network resilience. Companies have not yet provided sufficient justification for these forecasts and no allowance has been made. Ofgem will consider this further if companies provide appropriate justification including, in particular an explanation of how this expenditure would provide value for money for consumers.

Incentives for the speed and quality of telephone response

4.63. The March document set out Ofgem's further thoughts on incentives for the speed and quality of telephone response.

[31] Interim arrangements for storm compensation arrangements announced", Ofgem Press Release, R/104, November 2003.

Views of respondents

4.64. There was support in principle for increasing the scope of the survey to include consumers whose calls were answered by an automated message. However, respondents noted the technical difficulties of obtaining these phone numbers and that there may be high levels of costs involved.

4.65. There were mixed views on combining the quality and speed of telephone response by means of an additional question in the survey, with some companies feeling that this would be an improvement, whilst others felt that this would be a subjective measure of the speed of telephone response based on consumers' perceptions.

4.66. There were also mixed views on the form of the incentives with some respondents favouring a scheme based on relative performance and others favouring individual targets for each company.

Ofgem's proposals

4.67. The IIP incentive scheme introduced regular consumer surveys to assess the quality of service provided by DNOs. Since the survey started, performance has improved substantially – based on a scale of 1 to 5 (where 1 is the worst and 5 the best performance) all companies now average a score above 4.1 with some averaging above 4.5. This improvement, and narrowing of performance, raises questions about the way DNOs should be incentivised in the future. It is important that incentives are maintained, but a 'relative' mechanism whereby the reward (or penalty) is determined by performance relative to other companies, is not appropriate where the differentials in performance are very small.

4.68. **Ofgem therefore proposes to simplify the arrangements, with companies subject to a sliding-scale penalty if annual performance deteriorates below the current minimum average performance level (which is 4.1)**. If scores fall below 3.6 companies will be liable for the full penalty of 0.25% of revenue. **Ofgem also proposes a small reward of 0.05% of revenue for those companies with annual mean scores higher than 4.5.**

4.69. At present, the sample for the survey is taken from a list of consumers that have spoken to a person at the call centre. This is less than ideal, as the companies make extensive use of automated messaging. Ofgem will therefore continue to look to broaden the scheme (possibly to extend the scope in 2007) to include those customers that received a message. [32] **Ofgem proposes to retain the existing assessed survey questions, but also incorporate consumer satisfaction with the speed of telephone response.**

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

Undergrounding in Areas of Outstanding Natural Beauty

4.71. The March document set out that Ofgem was reviewing information provided by companies on the cost of undergrounding in national parks and areas of outstanding natural beauty and that this area was also being explored as part of the consumer survey.

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

Views of respondents

4.72. Relatively few respondents commented on the issue of undergrounding. However, those that did were in favour of allowances or incentives for undergrounding for amenity reasons.

Ofgem's proposals

4.73. The results of the survey indicate that consumers have some degree of willingness to pay for undergrounding in national parks and areas of outstanding natural beauty, although this is given a relatively low priority compared to some of the other improvements tested. In the light of these results, Ofgem has considered whether it should allow DNOs to pass on to their consumers the costs associated with undergrounding some existing lines in these areas.

4.74. This would provide real benefits to the public – depending on the extent of undergrounding carried out - but Ofgem does not consider that it is the appropriate body to make such decisions for the following reasons:

- improving visual amenity in this way is a "public good". That is, the benefits are realised by everyone who visits the area. The local DNO's consumers would therefore be paying to provide benefits that largely go to other people. Ofgem does not consider that it is its role to make such a decision. Such decisions are more appropriately taken by local or national government;

- in practice the amount of undergrounding that Ofgem could allow to be financed through distribution charges would be relatively small. The DNOs' forecasts suggest that it would cost around £6.9 billion to underground all lines in national parks and areas of outstanding natural beauty. It would not be legitimate for an economic regulator to make a decision on such a magnitude of costs associated with improving visual amenity; and

- it is questionable whether the expenditure of significant amounts of money on undergrounding would be consistent with the Social and

Environmental Guidance provided to Ofgem by the Secretary of State for Trade and Industry[33].

4.75. The initial proposals therefore contain no allowance for undergrounding for visual amenity reasons.

Environmental reporting

4.76. The March document consulted on introducing new reporting requirements covering sulphur hexaflouride (SF_6), oil pollution, amenity issues and environmental management systems.

Views of respondents

4.77. There were mixed views on the introduction of new reporting requirements in this area. Some respondents supported the proposals, whereas others felt that such requirements would impose an additional burden on companies. One respondent was disappointed that Ofgem does not intend to introduce financial incentives.

Ofgem's proposals

4.78. Reporting requirements will be introduced in the areas proposed under the RIGs. Environmental outputs will not be subject to financial incentives in this price control period. Work is continuing, in consultation with the DNOs, on the final form of the performance indicators and these will be published with the September update paper.

Discretionary reward

4.79. The March document suggested the introduction of a separately assessed discretionary reward which could cover areas of performance not addressed by

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[33] "Social and Environmental Guidance to the Gas and Electricity Markets Authority", DTI, 23 February 2004. Paragraph 4.1 of the Guidance states "Where the Government wishes to implement specific social or environmental measures which would have significant financial implication for consumers or for the regulated companies, these will primarily be implemented by Ministers, rather than the Authority, by means of primary or secondary legislation. The Government does not seek to do this through this Guidance."

other arrangements such as services to priority consumers and communication with key stakeholders during severe weather events.

Views of respondents

4.80. The majority of respondents supported the idea of a discretionary reward, recognising that there are many areas of consumer service that are not currently addressed under the IIP. Several respondents felt that the measurement criteria must be defined in advance if performance can be measured objectively.

4.81. Suggestions for areas that could be covered by the reward included the adoption of consumer service best practice. One respondent suggested that the reward could be shared by dividing it across a number of categories of consumer service. Another company felt that a discretionary reward would be too subjective.

Ofgem's proposals

4.82. **Ofgem proposes to assess performance using a two-part annual survey;** one part will request information from the DNOs on current practices and the other will be focused on key stakeholders such as social services, energywatch and other agencies.

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

4.84. The scheme will reward good practice, but there is no intention to penalise companies. Ofgem proposes that the total amount of reward available will be £1 million per annum in total (across all DNOs). The evaluation will cover the following three broad categories: priority customer care initiatives; initiatives relating to corporate social responsibility (e.g. activities with schools such as promoting safety awareness); and wider communication strategies implemented by DNOs (e.g. relationships with local health authorities or with other utilities in co-ordinating work).

Other issues

4.85. A number of companies have put forward forecasts for significant costs for improvements in quality of service specifically targeted at rural/worst-served consumers. In the light of the survey results, which show that there is little willingness of other consumers to help fund improvements in these areas, Ofgem has not included any additional allowance. Ofgem will consider this further if DNOs demonstrate that their proposals deliver net benefits to consumers.

Views invited

4.86. Views are particularly invited on the proposals on:

- revenue exposure to quality of service;
- the revised storm arrangements and associated cost allowances;
- targets and incentive rates for the number and duration of interruptions to supply; and
- changes to telephony incentives.

5. Distributed generation, the innovation funding incentive and Registered Power Zones

Introduction

5.1. Work on developing the incentive arrangements for distributed generation is well progressed and respondents to the March document did not raise any issues that require changes to the overall framework of the scheme. Further points of clarification of how the mechanism will work are set out in a separate Appendix. This also includes detailed points on the operation of the innovation funding incentive (IFI) and Registered Power Zones (RPZs).

5.2. Ofgem's initial views on the licence modifications that will be required to introduce the distributed generation incentive scheme are outlined in a separate Appendix.

5.3. The reporting arrangements for distributed generation, IFI and RPZs are set out in the draft Regulatory Instructions and Guidance (RIGs) for distributed generation published alongside this document.

5.4. The rest of this Chapter focuses on Ofgem's further thoughts on RPZs and the IFI where a small number of changes are proposed to the arrangements.

Innovation Funding and Registered Power Zones

5.5. The March consultation document, supported by the Regulatory Impact Assessment (RIA), confirmed Ofgem's commitment to the IFI and RPZs. This section sets out a number of specific refinements to the schemes in the light of responses to the March document.

Views of respondents

IFI

5.6. There continues to be wide support for most of the principles underlying the IFI both amongst DNOs and other interested parties. There was also support for introducing the IFI arrangements before April 2005. DNOs argue that the pass-through rate should be higher than the level proposed by Ofgem.

Registered Power Zones (RPZ)

5.7. There also continues to be wide support for most of the principles underlying RPZs. However, the majority of DNOs consider that the financial premium offered for RPZs is not sufficient to balance the greater risks involved. It has also been proposed that RPZs should embrace innovation applied to existing generators as well as new connections.

Ofgem's proposals – IFI

Pass-through Rate

5.8. Ofgem has concluded that its March proposal for a profiled pass through rate remains appropriate as this provides an appropriate balance between providing DNOs with protection as to costs incurred and incentives for efficiency. The allowed level of pass-through for each year is shown in Table 5.1.

Table 5.1: Pass-through for IFI

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

5.9. DNOs should fund a proportion of their R&D budgets themselves – this should have a positive impact on the IFI project selection processes. It is also likely to encourage DNOs to work together where there is genuine common interest in a particular R&D subject area. The first two years of operation of the IFI should provide good evidence as to whether the arrangements are likely to deliver the results intended and the review planned for 2007 will allow adjustments to be made if appropriate.

5.10. The next stage of development for the IFI will be to produce the necessary licence modifications and the reporting arrangements set out in the RIGs.

Good Practice Guide

5.11. Ofgem proposed in March that any company that wishes to pursue IFI funded projects will have to produce a good practice guide for managing R&D projects. The DNOs have indicated that they are working together on producing guidelines in this area. Ofgem expects to review these when they are available, If the proposed guidelines are not appropriate Ofgem will need to consider whether any specific guidance will need to be provided, and if so, what form this should take.

Implementation Date

5.12. **Ofgem proposes that IFI projects could be initiated from 1 October this year. Allowable costs incurred between 1 October 2004 and 31 March 2005 will be treated as if they had been incurred in 2005/6. They will be subject to 90% pass-through.**

5.13. A DNO will be required to inform Ofgem of its intention to take advantage of this facility by 1 September 2004. Ofgem will inform DNOs of the information it will require by 1 August 2004.

Ofgem's proposals – RPZs

5.14. The primary concern of the DNOs was in relation to the risk/reward balance for RPZs. For a DG connection with capex of £50/kW, the rate of return premium offered by RPZ status would amount to around 2 per cent. RPZs should demonstrate high quality innovation which could be more risky than 'normal projects' and as such Ofgem proposes an increase in the RPZ premium from the level set out in the March document.

5.15. **It is proposed that the incentive rate previously proposed (i.e. £3/kW) should be increased to £4.5/kW (i.e. three times the incentive rate under the**

distributed generation incentive scheme) - for the first five years of operation. This increases the rate of return for a £50/kW RPZ connection to 11%. This rate of return offers a significant premium to DNOs to reflect the additional risks that they may incur. The previously proposed cap of £0.5 million per annum remains in place.

Other issues

5.16. The development of the RPZ incentive has raised a number of issues that will only be properly exposed as real projects are proposed and considered for registration. In recognition of the learning curve that all parties will experience **it is proposed that for the first two years RPZ applications for registration should be limited to two per licensee per year**. This will also focus attention on the most innovative projects which is consistent with Ofgem's preference for a small number of high quality projects.

5.17. At the proposed review in 2007 this limit on applications will be reconsidered together with any other aspects of the scheme that need modifying but Ofgem does not intend to change the overall financial cap of £0.5m per licensee which will apply for the period of the next price control.

Views invited

5.18. Views are invited on any of the issues raised in this Chapter and in particular on:

- **IFI –** Ofgem would wish to know which DNOs intend to initiate IFI projects before 1 April 2005 by 9 August 2004; and
- **RPZ –** comments would be welcomed on the proposed changes to the RPZ incentive and the likely impact on DNOs' plans to develop RPZs.

6. Cost assessment

Introduction

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

6.2. Over the past year, Ofgem has devoted substantial resources to assessing the companies' historical and forecast costs. It has been advised by PB Power on capital expenditure (capex) and, for some aspects of operating costs (opex), tax and pensions by Ernst and Young. Deloitte and Touche have also provided some advice on pensions. Ofgem has also been advised by Duncan Whyte, former COO and FD of ScottishPower, across a range of issues.

Information collection

6.3. The cost assessment work began with the specification of detailed information requests. Collection of historical and forecast information was separated to spread the workload. A number of meetings of the cost assessment working group were held to discuss the development of the questionnaires and drafts were shared with the companies to allow them to comment at an early stage.

6.4. Completed questionnaires for historical information were received in September 2003. Completed questionnaires for forecast information were received in two stages - December 2003 and January 2004.

6.5. On reviewing the completed questionnaires, it became evident that the DNOs took different approaches or interpretations on various issues. This gave rise to resubmissions of historical information in November 2003 and numerous other amendments by DNOs. There has been a continuing exchange of information with the DNOs for the past 12 months. Some DNOs have continued to resubmit information originally requested in the questionnaires - including a resubmission from two groups as late as the end of May 2004. It has not been possible to incorporate all of the recent resubmissions in this document.

6.6. Three issues are evident from this experience:

- the delivery of final proposals could be jeopardized if further corrections and updates continue to be made on a piecemeal basis over the next several months. DNOs have therefore been asked to provide actual data for 2003/04 and any necessary and material updates to their forecasts by the end of July with the intention of minimising the need for further changes thereafter. Further changes after that date will only be accepted at Ofgem's discretion and may be specifically itemised in future documents;

- the process of data collection and verification has been burdensome on both Ofgem and the DNOs. There would be merit in moving to an annual system of data collection, with more detailed specification of the information in advance. This would require additional resources from both Ofgem and the companies to establish. In informal discussions, all of the DNOs have supported this concept, although some with reservations over the cost; and

- the degree of "normalisation" required has made comparisons more difficult than Ofgem had hoped. Some DNOs have argued that this introduces uncertainty in the comparative analysis. In Ofgem's view, the normalisation work has improved the robustness of the analysis and it is not appropriate for consumers to pay higher charges because of the differing approaches taken by companies.

Company visits and meetings

6.7. Ofgem and its consultants have visited each group on a number of occasions, including 2-3 day visits in October/November 2003 and February 2004, and one day visits in March (Ernst & Young) and in April/May. The 2-3 day visits covered detailed discussion of the historical and forecast business plan questionnaires respectively and the October/November visit also discussed capex forecasting processes. The final meetings in April and May discussed a near-final normalised cost analysis, an early regression analysis and issues arising on both capex and opex.

6.8. Ofgem has met jointly with all the DNO groups in a monthly working group on cost assessment since March 2003 and with a separate group to discuss capex modelling on 4 occasions. Both PB Power and Ernst & Young held feedback meetings with each of the DNO groups in mid-May.

Operating costs

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

- reviewing the cost and efficiencies achieved by DNOs during the existing price control period, their projected efficiencies for the rest of this price control period and the next;
- developing "normalised" and comparable cost information using actual costs from 2002/03;
- comparing actual normalised costs, using top-down benchmarking, to help estimate efficient cost levels;
- considering other information on efficiency, including DNOs' forecasts of changes in activity levels and new future costs, adjusting results where necessary, and rolling forward to 2010; and
- adding back other cost items estimated separately (e.g. network rates, pension costs, etc) to give the final opex allowance.

6.10. In the first three years of the existing price control period the DNOs have made significant cost savings and efficiency improvements. These were summarised in the December 2003 document. In their forecasts, DNOs are assuming that much smaller efficiency gains will be achievable in the future. Some DNOs have included some items that increase costs in their forecasts whilst others have excluded these items. DNOs' forecasts were summarised in the March 2004 document.

6.11. In view of the different approaches and assumptions used by DNOs, and the need to protect consumers' interests, Ofgem has made adjustments to improve comparability and used comparative analysis to assess the scope for future efficiency.

Normalisation

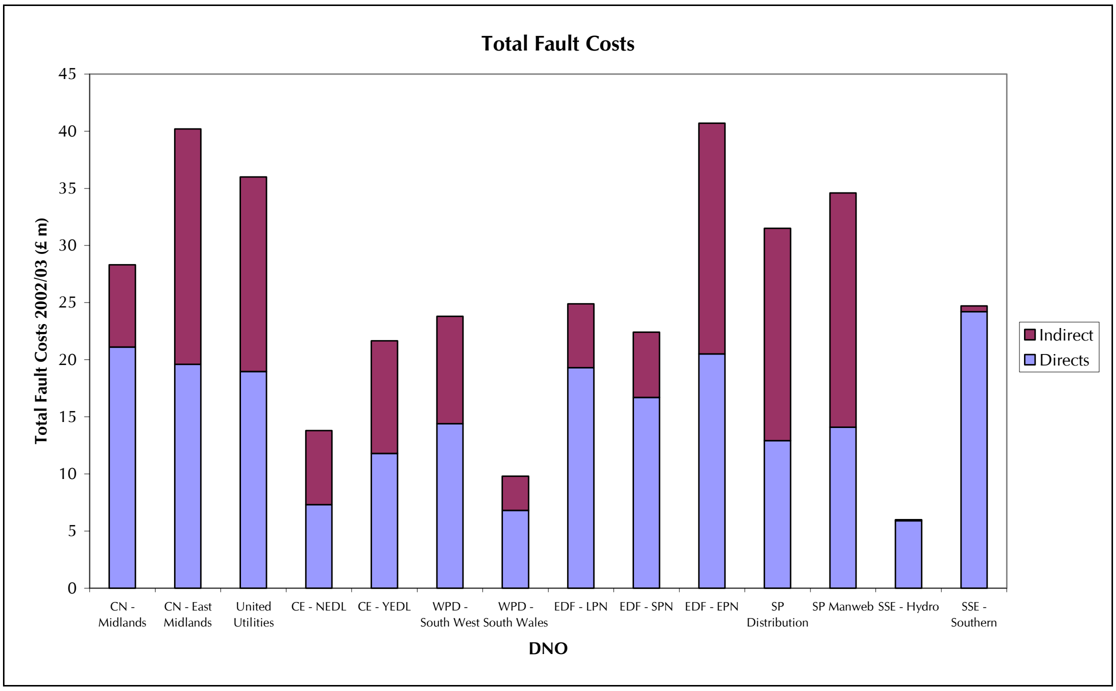
6.12. Robust benchmarking analysis requires good quality comparable data. Ofgem has made a number of adjustments to DNOs' costs to improve comparability across the sector and considers that these adjustments provide sufficient comparability for the purpose of regression analysis. Ofgem has focused on 2002/03 costs as this was the final year of outturn data available. Ofgem has requested outturn 2003/04 costs by the end of July and will review this data in August to see whether, and how, it should be taken into account.

Fault costs

6.13. One of the main areas of difference across DNOs has been the allocation of costs to a category termed "fault costs" (i.e. the costs of repair and restoration after a fault), and within that category to operating or capital expenditure. This is a substantial category of costs for most companies and differences in allocation can impact on the results of the benchmarking analysis.

6.14. Ofgem's intention at the start of the review was to assess fault costs separately. It became evident, on reviewing the data, that there were significant inconsistencies across companies due to accounting differences – the largest being the extent to which indirect costs were included within reported fault costs. This is shown in Figure 6.1.

Figure 6.1: Total fault costs 2002/03 (£ m, 2002/03 prices)



6.15. Although differences in indirect cost allocation can be adjusted for, there are other anomalies in reported fault costs that are more difficult to adjust. Both these accounting differences and other issues mean that it is more practical and robust to add all fault costs to operating costs before drawing comparisons across companies. Most DNOs generally agree with this approach although a few have expressed some concerns.

Overview of normalisation adjustments

6.16. The other main normalisation adjustments have been:

- exclusion of network rates, depreciation, exit charges, non-trading rechargeables, other cost of sales, Ofgem licence fee, and costs associated with 'de-minimis' activities. These costs are either outside the price control or the subject of separate assessment;

- exclusion of metering costs, as metering is not to be covered by the distribution price control;

- removal of atypical and one off costs, as these are not representative for the purpose of comparisons across companies or years (e.g. storm costs);

- removal of intra-company margins (e.g. profit margins on recharges from related parties), as these are not genuine “costs”. Where the related party’s business is predominantly external to the group inclusion of an internal margin is being considered. But for the purposes of this paper all margins have been excluded;

- adding back projected average non operational capex - for some companies non operational capex costs are included in an outsource contract and cannot readily be excluded, so comparable data is most easily provided by adding back the costs for those companies that incur the costs in-house. However, capital expenditure in any single year may not be representative, so the average forecast over the period 2005-10 has been used;

- removal of storm insurance costs for those companies that insure for these costs as this has been treated as an atypical cost;

- pensions, for which actual costs have been removed and replaced by a standardised rate of 15% for comparison. A separate allowance has been calculated for pensions (see chapter 7);

- adjustments to the capitalisation of overheads. DNOs have adopted different business models and overhead allocation methods. This has resulted in non-comparability of operating costs as some DNOs capitalise significantly different proportions of their overhead;

- adjustments for operating costs of 132kV in Scotland (due to different a definition of distribution in Scotland);

- adjustments for regional factors to take account of significant geographical, demographic and operational circumstances; and

- other excluded items and adjustments include lane rentals and congestion charges, adjustments for capitalisation policies not compliant with Regulatory Accounting Guidelines (RAGs), revenue protection costs, R&D costs, fault boundary adjustments, and removal of DNO normal pension costs and inclusion of Ofgem's view of normal pension costs.

6.17. Exclusion of costs at this point does not, in most cases, represent a disallowance of costs. Some costs are outside the price control, others will be covered by separate allowances. Other adjustments may be a transfer to (or from) capex. The only costs disallowed completely are inter and intra-company margins, but as explained above, where the related party's business is predominantly external to the group inclusion of an internal margin is being considered.

6.18. Table 6.1 sets out a summary of the normalisation adjustments – further details are in Table A1 in Appendix 1.

Table 6.1: Normalisation of DNO's Opex and total fault costs 2002/03 (£m)

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	(1)	-	68
CN - East Midlands	71	(11)	-	2	-	2	-	63
United Utilities	43	20	(2)	7	(4)	5	-	69
CE - NEDL	43	(1)	(1)	3	(8)	4	-	41
CE - YEDL	57	(1)	(0)	-	(9)	5	-	52
WPD - South West	40	8	(1)	7	(0)	0	-	53
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	-	(4)	-	69
EDF - EPN	88	(8)	(6)	10	6	(2)	-	89
SP Distribution	61	(4)	(5)	-	8	0	4	64
SP Manweb	61	(4)	(5)	-	1	0	-	54
SSE - Hydro	36	(0)	(1)	0	-	0	0	35
SSE - Southern	63	(3)	(2)	1	3	(1)	-	60
Total	**793**	**(12)**	**(26)**	**49**	**7**	**9**	**(2)**	**817**

Notes

1) HBPQ Opex + Faults shown here already excludes metering costs, rates, Ofgem licence fee, depreciation and exit charges.

2) Figures have been rounded to the nearest £ million, 0 indicates a figure below £0.5 million

6.19. Two of the normalisation adjustments merit further description – those relating to overheads and regional factors.

Overhead allocations

6.20. As part of the normalisation process, adjustments have been made to overhead allocations, to bring the proportion of indirect costs capitalised into a comparable range across all companies. The adjustments have been made based on information provided by the companies. The data provided and Ofgem's adjustments are shown in Table A2 in Appendix 1.

6.21. The average proportion of overheads capitalised across all DNOs is 38%. A band of 5% either side of the average (33% – 43%) has been applied to allow for differences in activity levels between companies and also for any differences in the classification of indirect costs. Adjustments have been made to DNOs outside the band, either reducing their proportion of indirect costs capitalised to the top of the band (43%) or increasing them to the bottom (33%). Where a DNO's proportion of indirect costs capitalised falls within the band no adjustment has been made.

Regional factors

6.22. As at previous reviews, adjustments have been made for regional factors - costs specific to a particular area or region (e.g. higher labour costs in London and costs associated with the Highlands and Islands of Scotland).

6.23. Several DNOs have provided qualitative or quantitative arguments for additional regional factors. Several have suggested that all companies have such regional factors and, with some exceptions, these approximately cancel out. EDF has argued that the areas it serves are disproportionally affected by factors such as wages and property prices and submitted a report by OXERA quantifying the impact.

6.24. Adjustments for regional factors may be appropriate where there are justifiable differences in costs due to factors that are outside the companies' control that are not captured by the composite scale variable (see below).

6.25. Ofgem is persuaded that such circumstances apply to EDF-LPN and SSE-Hydro. The size of the adjustments Ofgem has made are broadly in line with those applied at the last review in 1999 - adjusted for efficiency and inflation. In addition, SSE-Hydro have suggested that they will face additional costs following implementation of British Electricity Transmission Trading Arrangements (BETTA) relating to generation balancing on Shetland. This issue is under consideration.

Conclusion on normalisation

6.26. Ofgem has now identified and addressed the most significant inconsistencies in the 2002/03 costs and does not propose to make any further significant adjustments.

6.27. Ofgem will assess 2003/04 costs over the coming months. Some companies have argued that some elements of their costs were atypically low in 2002/03 – the analysis of 2003/04 costs will assist in this assessment.

Top Down Benchmarking

6.28. Normalised costs can be compared using statistical regression techniques. There are only 14 separately licensed DNOs, which at the start of 2002/03 were owned by 9 groups (with further consolidation to 8 groups during 2002/03 and 7 now)[34]. A small number of data points means that it is important to restrict the number of explanatory variables to those which can be measured robustly and have a statistically significant impact on costs.

Composite scale variable

6.29. As at previous reviews, Ofgem has assumed that operating (and fault)[35] costs are primarily driven by the scale of the business. Scale is measured by three variables: network length, number of customers and units distributed. Units distributed are closely correlated with customer numbers. To minimise the number of explanatory variables, these three factors are weighted and combined into a composite scale variable (CSV).

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[34] Acquisition of SEEBOARD (now EDF – SPN) by EDF Energy completed August 2002; acquisition of Aquila (now CN – Midland by Powergen (owner of CN – East Midlands) completed January 2004.

6.30. The choice of weights is intended to reflect the influence of the various factors on the operating costs of the companies. Ofgem has considered this from an engineering, statistical and commercial perspective and discussed the issue with the DNOs. Some companies have argued that network length is the main cost driver; others that it is customer numbers.

6.31. Ofgem's main analysis uses weights of 50% for network length and 25% for customer numbers and units distributed. The data used for each of the components and the calculated CSV are shown in Table 6.2.

Table 6.2: Calculation of the CSV[1]

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

Note: 1 CSV is calculated as $A^{0.5} \times B^{0.25} \times C^{0.25}$

6.32. Some DNOs have argued that separate weights should be applied to overhead and underground network length, with a higher weight on the latter. Analysis of data linking costs to assets does not support this. This analysis also shows that companies have attributed almost half of operating and fault costs to overhead lines or underground cables, or to wayleaves.

[35] For the remainder of this section, unless otherwise specified, the term operating costs is used to include fault costs.

6.33. Sensitivity analysis has been undertaken using alternative weightings. The DNOs most sensitive to weightings of the scale variable are SSE-Hydro (as a long and sparsely populated network it is positively affected by high network length) and EDF-LPN (being a small but dense network it is adversely affected by a high weighting of network length).

Basic regression

6.34. The regression applies a "line of best fit" to normalised costs. This line represents the average costs of all 14 companies. Those companies furthest below the line are lowest cost, and vice versa.

6.35. There are various ways of using this analysis to form judgements on future costs. One would be to assume all companies could catch-up to the lowest cost firm (or "frontier" firm). Another would be to assume that all companies move to the average.

6.36. At the last review, Ofgem assumed all companies could catch-up 75 per cent of the gap to the two firms with lowest cost. In the five year period from 1997/98 to 2002/03, almost all DNOs outperformed this assumption, and most have moved beyond the 1997/98 frontier.

6.37. Taking this into account, along with evidence on total factor productivity[36] and from a review of the DNOs' forecasts, Ofgem is confident that, over the period 2005-2010, DNOs should be able to achieve cost levels below the sector average in 2002/03. Ofgem's view is that, in principle, cost efficiency levels that are already being achieved by several companies in 2002/03 should be achievable by all companies from 2005. Ofgem also expects that even the lower cost companies will continue to improve from their existing position. Some of the lower cost companies, in their own forecasts, also expect to achieve annual efficiency savings of 1 – 2 per cent.

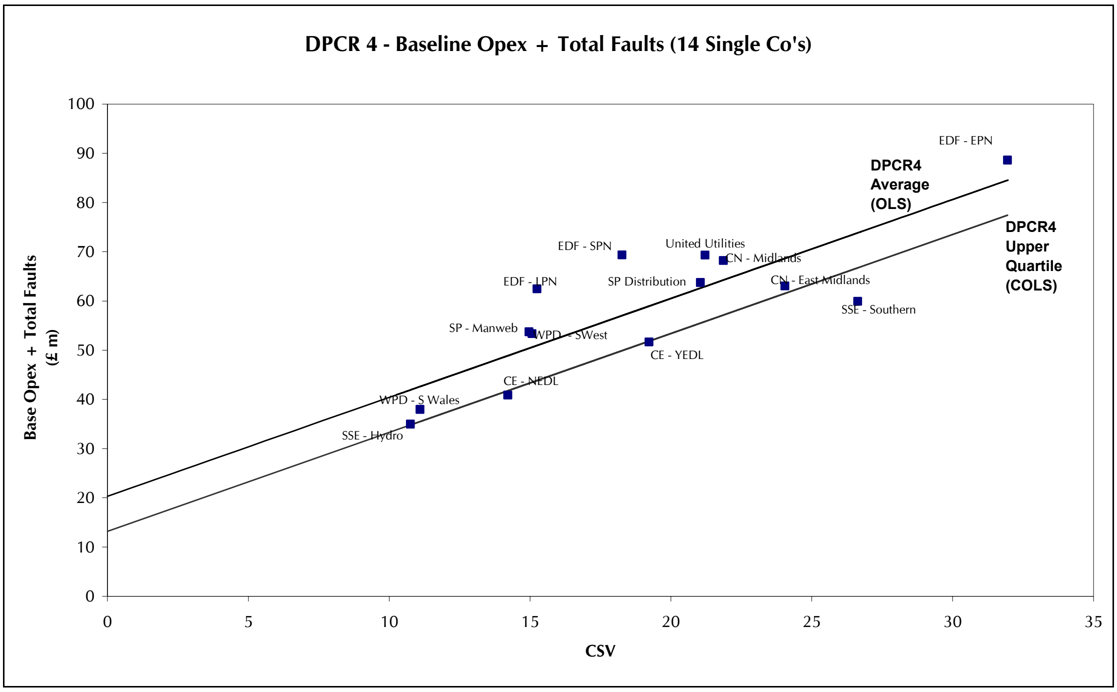
6.38. In applying this approach it is important to be confident that the benchmark is not defined by a company(ies) that is 'trading' low costs for poor quality of service. Although there is no evidence that the lowest cost company is in this

[36] Productivity improvements in DNOs - Final Report, Cambridge Economic Policy Associates, Dec 2003.

position, it would not be prudent to use a single company as the benchmark. The regression analysis shows that there is a cluster of companies with slightly higher costs than the frontier, but forming a grouping around the upper quartile. The companies around the upper quartile (SSE Southern, SSE-Hydro, CE- NEDL, CE-YEDL and WPD-S Wales) are generally good performers in terms of quality.

6.39. A reasonable approach would be to use the upper quartile as a benchmark. This provides a more robust and sustainable benchmark than a frontier based on one company. The regression (average) line is therefore shifted downwards so that it passes through the upper quartile – between the third and fourth of the fourteen companies. Figure 6.2 shows the regression analysis.

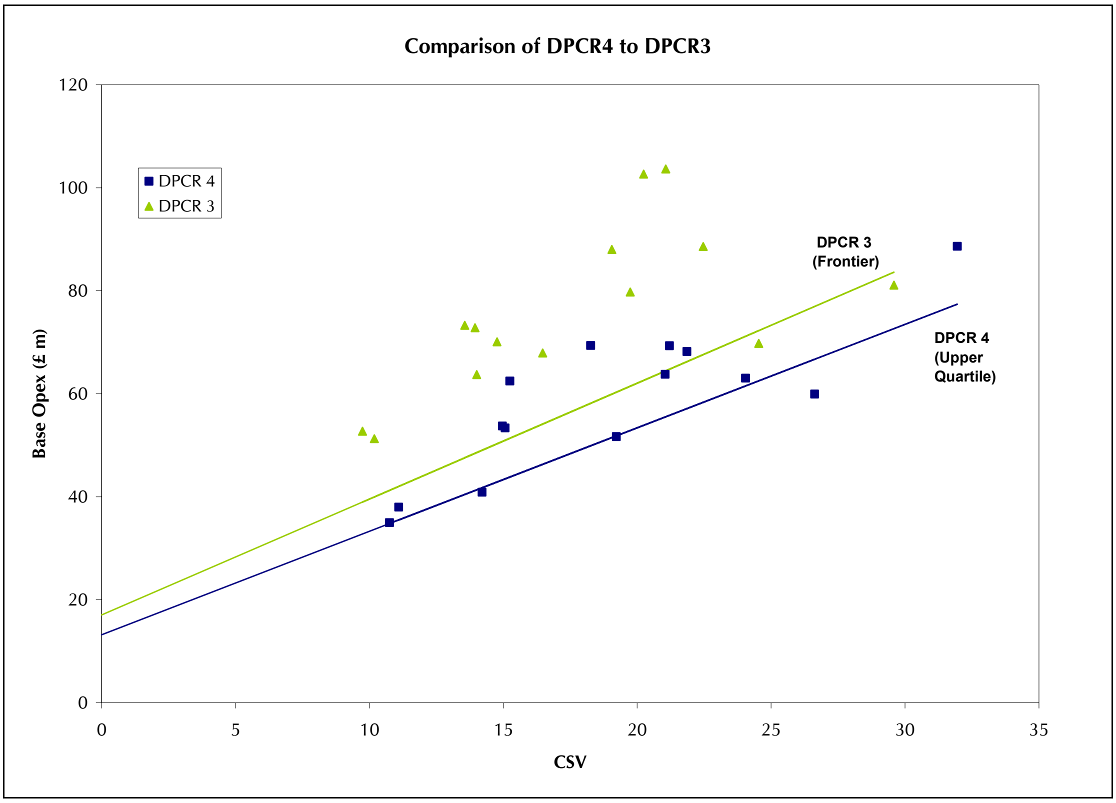
Figure 6.2: Baseline regression normalised opex 2002/03



6.40. Ofgem has discussed an earlier version of this analysis with the DNOs. All have argued that Ofgem should use the average benchmark rather than an upper quartile. It is highly likely that, for the categories of costs considered in this analysis, costs over the period 2005-10 will, on average, be lower in real terms than the upper quartile levels in 2002/03. There are already six DNOs very close to or ahead of the upper quartile.

6.41. Figure 6.3 illustrates the DPCR4 upper quartile benchmark and DPCR4 normalised costs and a comparison with the costs from the last review (which used 1997/98 costs – which have been inflated to 2002/03 prices) along with a frontier benchmark using the same method used at that review. In both cases the CSV used is weighted network length 50%; customer numbers 25% and units distributed 25%.

Figure 6.3: Comparison of DPCR 3 and DPCR 4 benchmarks



2002/03 costs include certain costs which may have been omitted from 1997/98 e.g. some capitalised fault costs, but exclude others such as metering costs. Overall, the difference between DPCR 3 and DPCR 4 is likely to be understated

6.42. There are two key features to note from Figure 6.3:

- there is greater convergence of costs now than at the last review; and
- the proposed movement in the benchmark is much less than many of the companies have achieved since the last review.

Alternative regression analyses

6.43. Some companies argued for different weightings in the scale variable (see above), for use of 9 data points (combining DNOs in common ownership) instead of 14 or otherwise taking account of non-merged companies and for inclusion of quality and/or total costs in the analysis. Ofgem has considered each of these issues.

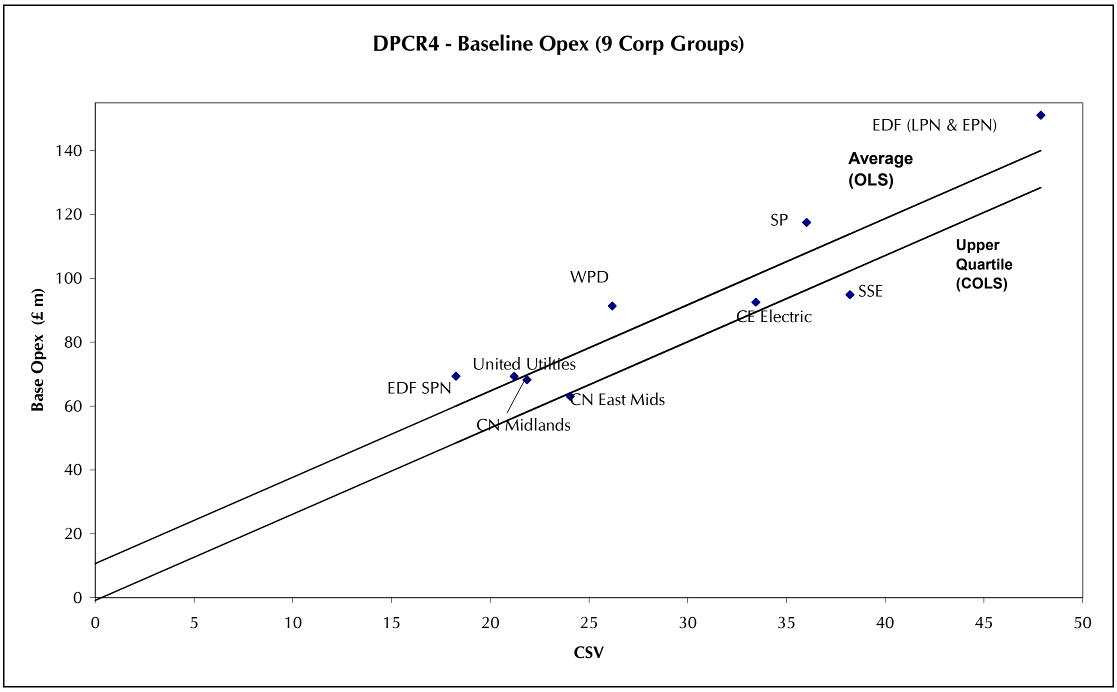
9 ownership groups / mergers

6.44. Ofgem has considered regressions using the 9 ownership groups in existence at the start of the 2002/03 year. These are Aquila (now CN-Midlands), EME (now CN – East Midlands), EdF (EPN & LPN), WPD, United Utilities, Scottish Power, SSE, CE Electric and SEEBOARD (now EDF – SPN).

6.45. Overall, the results shown in Figure 6.4 are quite similar to those from using 14 data points although some companies are closer to the benchmark (noticeably EDF and Central Networks) and others further away (e.g. WPD and CE Electric).

6.46. Other than consideration of the 9 group model, Ofgem does not propose any specific adjustment for non-merged or merged companies. As discussed in the March document, savings achieved by merged DNOs are attainable through other corporate structures and not exclusive to mergers between DNOs - therefore adjustments for merger savings are not necessary.

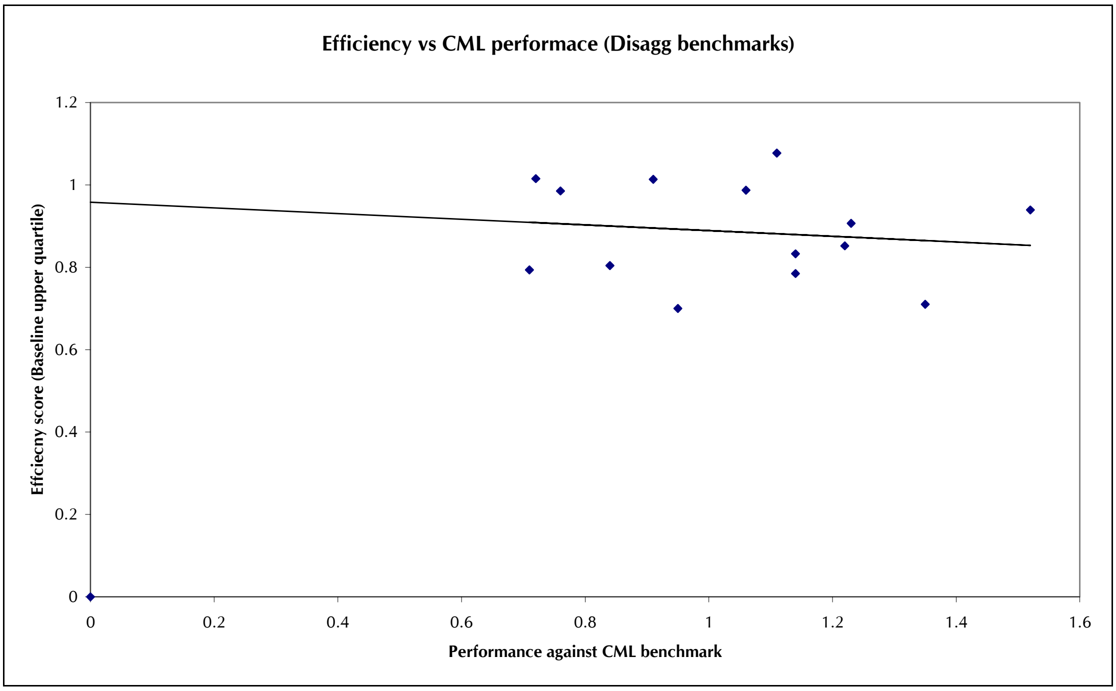
Figure 6:4 Baseline regression opex 2002/03 9 company groups



Quality of service

6.47. Ofgem has carried out regression analysis incorporating measures of quality of service performance. Figure 6.5 shows a regression of the "efficiency scores" from the basic regression against benchmark CML performance (see Chapter 4) – this assesses the extent to which quality differences explain cost differences. The quality variable in the regression is not statistically significant (the slope of the line shown in the graph is not statistically distinguishable from zero).

Figure 6.5: Two stage regression – efficiency versus CML performance



Total cost analysis

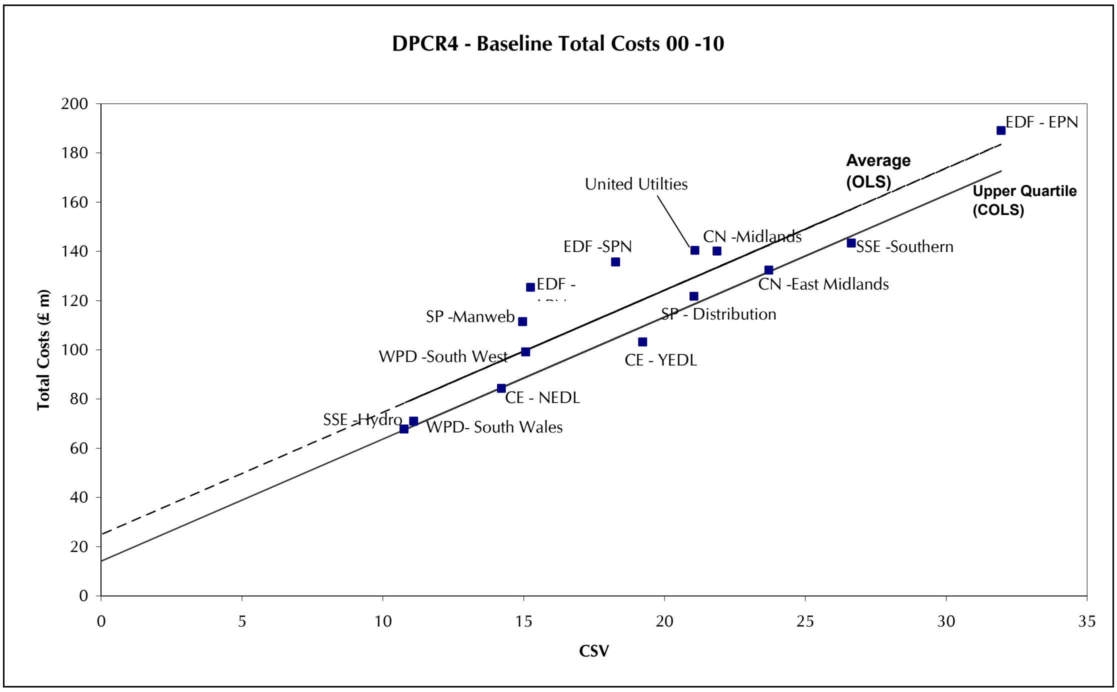
6.48. Ofgem has considered various versions of total cost analysis. Traditional specifications include operating costs and a measure of the use of capital stock. Reports[37] commissioned by Ofgem as part of this review have explained the problems of defining capital stock. Having run the regressions, it is apparent

[37] "Developing Network Monopoly Price Controls: Workstream B, Balancing Incentives", Frontier Economics, March 2003 & Productivity improvements in DNOs - Final Report, Cambridge Economic Policy Associates, Dec 2003.

that the results tend to be dominated by the chosen capital stock measure (because the capital cost component tends to be substantially bigger than the operating cost component). This suggests that these measures are not necessarily a good indication of operating cost efficiency. Further, companies with historically low capex are in some cases now forecasting much higher capex over the period 2005-10. This would raise the issue of double counting if they were rewarded for low historic capex in the opex analysis and also given higher future capex.

6.49. In an attempt to overcome these problems, Ofgem has also considered adding average capital expenditure over the ten year period 2000-2010 to operating costs, using PB Power's view of future capital expenditure – see Figure 6.6. If the percentage gap to the upper quartile is applied to normalised operating costs, this gives the results shown in the "total cost" column of Table 6.3. This model does not have strong theoretical foundation and is sensitive to the assumptions used (e.g. the results would be different if the input data used different views of future capex). It Is therefore not appropriate to place too much weight on this analysis.

Figure 6.6: Regression of total costs 2002/03 opex + total capex avg 2000-10



Conclusions on alternative regressions

6.50. None of the alternative regressions shown here, or any others put forward by the DNOs, are superior to the basic regression model in Figure 6.2 – and this will be used as the main analysis of efficiency. However, the 9 group model and the total cost model do provide some additional information on companies' efficiency which can be taken into account.

6.51. For these initial proposals, Ofgem has set opex allowances (see Table 6.3) at the higher of the average of the three alternative regressions and the base regression. Table A4 in Appendix 1 contains more details of these analyses. Table A5 in Appendix provides an analysis which breaks down the average operating cost allowances included in the price control calculations in Chapter 8. The adjusted normalised controllable costs including faults that the efficiency percentages (derived from the above analysis) are applied to are shown in Table A3 in Appendix 1.

Other evidence and judgement

6.52. In support of top down analysis of opex and fault costs, Ofgem commissioned consultants Ernst & Young (E&Y) to assess the operational efficiency of the DNOs. E&Y has analysed a subset of operating costs - predominantly overheads and other corporate costs. Its qualitative assessment of companies' efficiency is broadly consistent with the results from the top-down benchmarking. In particular E&Y finds that SSE is the lowest cost and that United Utilities, CN-Midlands and the EDF companies are relatively high cost.

Tree cutting costs

6.53. Most companies are forecasting an increase in tree cutting activity above 2002/03 levels. Ofgem has reviewed DNO forecasts and modelled the direct costs of tree cutting. Based on this analysis, operating cost allowances have been increased to take future higher activity levels into account where appropriate. The additional allowances are intended to allow for the direct cost of the increased activity as Ofgem does not consider additional indirect cost allowances are warranted. No increase in allowance has been given for any tree cutting backlogs.

6.54. Ofgem has modelled tree-cutting costs in two ways - one based on the direct costs of performing this work in-house and the other on the average of existing third party contractor rates. The average of the results of these two approaches has been compared to the implied allowance for tree cutting in efficient regressed costs (assuming highest cost per CSV of the upper quartile companies). Where the average cost from the tree cutting model is greater than that implied from the regression, the allowance has been increased accordingly. Increases to the allowances are set out in Table A7 in Appendix 1.

Achieving the benchmark and glidepaths

6.55. Ofgem has considered whether or not to:

- assume companies only move a proportion of the way to the benchmark (e.g. 75% as applied at the last review); or
- phase the cost reductions over a period of time into the DPCR4 period (e.g. 3 years as at the last review).

6.56. Ofgem's initial view is that neither of these adjustments should be applied. Use of a catch-up percentage or "glidepath" extending past 2005 gives additional revenues to those companies revealed as highest cost. This risks creating perverse incentives. Not setting a glidepath may imply greater cost reductions for particular companies - this is consistent with those companies that are below average efficiency (i.e. both higher cost and not outperforming on other measures) earning less than the average cost of capital until they catch up.

Table 6.3: Calculation of DPCR4 Base Opex and total faults Allowance

DNO	2002/03 Adjusted Normalised Controllable Costs + Faults	Basic Regression 14 points (upper quartiler)	Total cost model 14 points (upper quartile)	Merged groups 9 points (upper quartile)	Average 2002/03 Efficient Costs (Upper Quartile)	Adjust to Higher of Average or Basic	Average 2005/10 (2% Frontier Shift)	Storm Insurance and Atypicals	Tree Cutting	QoS Average Opex	Proposed Average Allowance
	£m	£m						£m	£m	£m	£m
CN - Midlands	64	54	56	55	55	55	51	2	1	1	55
CN - East Midlands	61	59	60	62	60	60	57	1	0	1	60
United Utilities	65	52	55	53	53	53	50	1	-	1	52
CE - NEDL	38	39	38	37	38	39	37	2	0	1	40
CE - YEDL	48	49	51	47	49	49	46	1	-	1	48
WPD - South West	51	42	46	39	42	42	40	1	2	3	46
WPD - South Wales	36	34	35	27	32	34	32	2	2	1	37
EDF - LPN	66	46	47	56	50	50	47	-	-	1	47
EDF - SPN	66	48	51	46	48	48	45	1	-	1	47
EDF - EPN	84	74	77	72	74	74	70	2	3	2	76
SP Distribution	58	50	56	47	51	51	48	2	1	1	52
SP Manweb	51	41	41	42	41	41	39	1	2	1	43
SSE - Hydro	33	33	33	36	34	34	32	2	1	1	36
SSE - Southern	56	63	58	61	60	63	59	2	1	2	64
Total	**778**	683	704	679	689	694	653	18	14	17	702

Notes:

2002/03 Adjusted Normalised Controllable Costs + Faults of £778.1m is as per the calculation included in Appendix 1.

QoS average opex includes revenue for WPD arising from outperformance of benchmarks (see Table 4.3).

Total opex allowance

6.57. Ofgem has calculated overall opex allowances by:

- reversing certain adjustments from the normalisation process (e.g. regional factors) and applying the efficiency adjustments implied by the regression analysis;

- rolling forward cost allowances by an assumed level of ongoing efficiencies. Based on a study of total factor productivity commissioned by Ofgem and on the companies' own assumptions for ongoing efficiencies, an assumption of continuing cost reductions of 2% per annum has been applied for all the years 2005/06-2009/10; and

- adding certain costs to produce the overall allowance: e.g. underlying atypical storm costs or insurance, and certain costs that are, or are likely to be, treated as pass-through (e.g. licence fee and business rates).

6.58. The ongoing cost reductions of 2 per cent per year have not been applied for the period 2002/03 to 2004/05. This provides an allowance for cost increases over this period but will need to be considered further in the light of updated information on 2003/04 and 2004/05 costs.

6.59. Table 6.4 sets out the network rates payable by the DNOs for 2005-10. The numbers are based on the latest Rateable Values (RVs) and Ofgem's latest view on the English, Welsh and Scottish poundages and transitional arrangements. The respective poundages and transitional arrangements will be finalised by the Office of the Deputy Prime Minister (ODPM) and Welsh Assembly in July, the Scottish Executive will finalise its arrangements in November 2004.

Table 6.4: DNO Network Rates 2005-10 (£ m, 2002/03 prices)

	Rates					
	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m
CN - Midlands	23	22	21	20	20	20
CN - East Midlands	25	22	26	27	27	27
United Utilities	18	18	17	17	17	17
CE - NEDL	13	12	14	14	14	14
CE - YEDL	22	21	19	19	18	18
WPD - South West	16	14	17	18	18	18
WPD - South Wales	12	11	13	14	14	14
EDF - LPN	21	18	21	23	23	23
EDF - SPN	15	14	13	13	11	7
EDF - EPN	25	25	26	26	26	26
SP Distribution	25	28	33	33	33	33
SP Manweb	15	14	14	13	12	12
SSE - Hydro	8	10	11	13	15	15
SSE - Southern	34	30	35	38	38	38

Conclusion on opex allowance

6.60. Table 6.5 sets out average allowances for each company calculated on the basis set out above before the addition of licence fees, rates or pension costs, compared to the company's own forecasts.

Table 6.5: Average Opex allowances 2005/06-2009/10 (£ m , 2002/03 prices)

DNO	2002/03 Adjusted Normalised Controllable Costs	Adjusted DPCR4 Average Forecast		Average DPCR4 Allowance		
	Excludes atypical items and all normalisation adjustments	Adjusted DPCR4 Average Forecast on similar basis as 2002/03	% Inc/(dec) over 2002/03 Normalised Controllable Costs	DPCR4 Allowance on similar basis as 2002/03	% Inc/(dec) over 2002/03 Normalised Controllable Costs	Adjusted DPCR4 Average Forecast as a % of Average DPCR4 Allowance
Note	1	2		3		
	£m	£m	%	£m	%	%
CN - Midlands	64	70	10%	55	(14%)	127%
CN - East Midlands	61	60	(1%)	60	(2%)	101%
United Utilities	65	73	12%	52	(19%)	139%
CE - NEDL	38	42	11%	40	5%	106%
CE - YEDL	48	53	9%	48	(1%)	110%
WPD - South West	51	55	9%	46	(11%)	122%
WPD - South Wales	36	36	0%	37	4%	96%
EDF - LPN	66	71	9%	47	(28%)	151%
EDF - SPN	66	68	2%	47	(29%)	144%
EDF - EPN	84	100	18%	76	(10%)	131%
SP Distribution	58	55	(4%)	52	(10%)	107%
SP Manweb	51	42	(18%)	43	(17%)	98%
SSE - Hydro	33	38	15%	36	8%	107%
SSE - Southern	56	66	17%	64	13%	104%
Total	**778**	**830**	**6.6%**	**702**	(10%)	**118%**

Notes:
1. 2002/03 Adjusted Normalised Controllable Costs is summarised in Appendix 1.
2. Adjusted DPCR4 Average Forecast is summarised in Appendix 1. The DNOs forecasts have been adjusted on a similar basis as 2002/03 Adjusted Normalised Controllable Costs.
3. Average DPCR4 Allowance is summarised in Appendix 1.

6.61. As explained earlier in this Chapter, the operating cost allowances set out here include capitalised faults and non-operational capex. It is therefore not necessarily appropriate to expense these costs in full in the year in which they arise for the purposes of setting price control revenue. This is discussed further in Chapter 8.

6.62. Further, as noted above, this analysis is based on 2002/03 costs and will be reviewed against 2003/04 actuals over the coming months.

Capital expenditure

6.63. The revenue calculations underpinning the price review depend on both historical and future capital expenditure. Capital expenditure over the period

1998/99 to 2004/05 feeds into the calculation of the Regulatory Asset Value (RAV) at the start of the control, as well as into the capex rolling incentive mechanism. The RAV over the period 2005-2010 then depends on capex allowances over that period and depreciation.

Historical capex and RAV roll forward

6.64. For this price control, the RAV needs to be rolled forward from 1 April 1998 to 31 March 2005 based on the policies used to set capex allowances at the last review. Previous documents have discussed the problems associated with doing this. This area of work is ongoing and requires further discussions with companies but initial estimates have been made for the purpose of these initial proposals.

6.65. Table 6.6 contains a summary of the adjustments made to companies' reported total capex (including capitalised faults) to roll forward the RAV. Table A8 in Appendix 1 sets out further details. Table A8 also contains deductions from the RAV for the assumed value of metering assets which have been removed from the distribution RAV.

6.66. Ofgem emphasises that Table 6.6 contains only an initial view of the appropriate adjustments for rolling forward the RAV, that the opening values as at 1 April 2005 are likely to change and that for some companies these changes could be material.

6.67. The main areas where Ofgem considers adjustments are required are:

- **margins** - The approach to related party margins in DPCR3 was clear in that they were excluded unless 50% or more of the turnover of the related party was to external companies. Ofgem has therefore applied this rule to the margins included in the capex that the companies have incurred and will exclude margins from the roll forward of the RAV;

- **non-operational capex** - For DPCR3 a £3m non-operational capex allowance was made as a revenue allowance (i.e. opex allowance). Ofgem will exclude non-operational capex or depreciation on non-operational capex (where the non-operational capex is incurred in a service provider) from RAV additions;

- **fault capitalisation** – Ofgem's understanding of the treatment of faults for the RAV roll forward was set out in the December paper and this was supported by some companies. In that document Ofgem identified that it needed to review evidence from the companies before taking decisions. Ofgem is in the process of doing this but it is clear that some adjustment should be made, albeit potentially less than indicated in December. Most companies accept this but the scale of the adjustments have not been agreed. Ofgem has included initial estimates of these adjustments in Table 6.6;

- **overheads** - Since DPCR3 there has been a marked change at some companies in the extent to which they capitalise overheads. In principle, companies should not be allowed to increase their RAV (and hence obtain higher revenues in future) by changing their accounting in this way. Ofgem is presently reviewing this issue but is not in a position, at this stage, to calculate an adjustment - so for the purposes of this document no adjustment has been made for this item in Table 6.6.

  However this adjustment could be material for some companies. In order to seek the views of companies and others, Ofgem's initial view of the adjustments that <u>could be</u> applied for those companies who would be most affected by this adjustment are:

  - an addition to RAV for the CE group of companies of £60m;
  - a deduction from RAV for the SP group of companies of £46m; and
  - a deduction from RAV for the EDF group of companies of £26m.

  These initial views of adjustments have been calculated for 2002/03 to 2004/05 where data is more readily available and <u>would be in addition</u> to those shown in Table 6.6. Ofgem intends to report further on this issue in the September document; and

- **disposals** - As discussed in the March document Ofgem is considering the treatment of assets disposed of by the companies. Ofgem is in the process of reviewing data provided by the companies and intends to report further on this issue in the September document. Again, the changes could be material and in this case would only reduce the RAV if adjustments are applied.

6.68. The other main adjustment is for meter recertification costs which have been included in the RAV from 1 April 2000 in accordance with a commitment made by Ofgem in DPCR3. There are also a number of other less material issues being discussed with the DNOs.

Table 6.6: Summary RAV roll forward (£ m, 2002/03 prices)

DNO	DPCR3 adjustments					
	00/01-04/05	00/01-04/05	98/99 - 04/05	02/03 - 04/05	98/99 - 04/05	
	Meter recertification	Repairs / Faults	Margins	Non-op dep	Other	Total
	£m	£m	£m	£m	£m	£m
CN – Midlands	3	(22)	0	(15)	(10)	(44)
CN – East Midlands	7	0	0	0	9	16
United Utilities	7	(38)	0	0	(9)	(41)
CE – NEDL	9	(13)	(24)	0	8	(19)
CE – YEDL	9	(59)	(5)	(7)	0	(63)
WPD – South West	3	10	(0)	0	0	12
WPD – South Wales	4	8	(1)	(0)	0	11
EDF – LPN	2	(23)	(7)	(6)	0	(34)
EDF – SPN	1	(41)	0	0	(8)	(49)
EDF – EPN	1	(31)	(7)	(9)	1	(46)
SP Distribution	12	(7)	(25)	(24)	(4)	(48)
SP Manweb	20	(5)	(30)	(18)	(4)	(37)
SSE – Hydro	15	(4)	(1)	(1)	(5)	4
SSE – Southern	27	(20)	(3)	(2)	(8)	(5)
Total increase/(decrease)	118	(244)	(104)	(84)	(30)	(343)

Notes:

1 These are the adjustments that have been made so far to roll forward RAV on to a comparable basis with the DPCR3 allowances. Ofgem is still evaluating information received from the DNOs and is seeking additional clarification before the adjustments are finalised.

2 Most of these adjustments apply to the years 98/99 - 04/05 but at the moment data is only available for the years shown above.

3 Other areas that are being looked at include overheads, pension costs and asset disposals. For some DNOs these areas are material.

4 The above adjustments and the overhead adjustment are linked and, in particular, the calculation of the overhead adjustment is dependent on all the other adjustments being made first.

5 Explanation of adjustments which are to adjust DNOs capital expenditure on to the basis of the DPCR3 allowances:

Meter recertification: was treated as operating expenditure pre 1 April 2000 and in accordance with the DPCR3 proposals has been treated as capex in 00/01 to 04/05.

Repairs: adjustment to treat certain cable and overhead line repairs as operating expenditure.

Margins: adjustment of inter-company margins where a related party derives less than 50% of its turnover from third parties.

Non-operational depreciation: to eliminate capitalised depreciation of non-operational assets as this was all treated as an opex allowance in DPCR3.

Other: to exclude capitalisation of operational IT and control room costs, including meter rectification from 98/99 to 99/00.

Review of future capex

6.69. This section sets out comments and views on the base case scenario (i.e. assuming current quality performance is maintained) capex plans submitted by the DNOs in the FBPQ.

6.70. Quality of service targets that have been set by Ofgem (see Chapter 4) differ from those set out by Ofgem in the FBPQ quality of service scenarios due to updated analysis. Capex allowances relating to the targets now proposed by Ofgem are set out in Chapter 4.

6.71. PB Power and Ofgem have reviewed the capital expenditure forecasts provided by the DNOs and have developed models for both load-related expenditure (LRE) and non-load related expenditure (NLRE). The findings of both the detailed reviews and the model methodology have been discussed with the companies. The timing of information flows and visits has been outlined earlier in this Chapter.

6.72. Customer contributions included in PB Power's views are based on the FBPQs. This matter will be given further consideration. Ofgem is expecting companies to restate contributions in the light of the proposed changes to the structure of charges.

6.73. LRE has been modelled by benchmarking the DNOs forecast and historic spend as a proportion of Modern Equivalent Asset Value (MEAV) per customer and per GWh. The model considers a 15 year period from 1995 to 2010. The model applies the median ratio of future to historic spend for each DNO to arrive at the LRE projection.

6.74. The NLRE model uses the DNOs' asset populations at March 2003 and applies a replacement profile for each asset category. The replacement profile used is the same for all DNOs – and is based on the DNOs' own profiles included in the FBPQs. The same set of unit costs (as advised by PB Power) have been applied to all DNOs, although an adjustment has been made for EDF-LPN to reflect regional factors.

6.75. A slightly modified approach has been used for overhead lines. A high proportion of overhead lines are refurbished rather than replaced therefore overhead lines have been modelled using assumptions on refurbishment cycles and proportion of replacement.

6.76. Expenditure on meters, faults and ESQCR compliance has been excluded from the forecasts as they are considered elsewhere, as have all pension deficit funding costs.[38] Metering will be subject to a separate price control. Capitalised fault costs have been considered along with opex and an allowance calculated to cover both together.

6.77. Certain normalisation adjustments have been made to the projections (e.g. in relation to margins and overhead allocations) for reasons discussed above in relation to operating costs - see Appendix 1 for details.

6.78. Taking all of the above into consideration an initial view has been formed on the relevant capital expenditure allowances.

View of allowances for initial proposals

6.79. PB Power's view of capex allowances for each company is set out in Table 6.7.

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[38] Table 6.12 shows this adjustment.

Table 6.7: DPCR4 Capex forecasts (£ m, 2002/03 prices)

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	333	487	46%	442	33%	110%
CN - East Midlands	307	457	49%	419	36%	109%
United Utilities	345	455	32%	439	27%	104%
CE - NEDL	244	254	4%	254	4%	100%
CE - YEDL	272	335	23%	314	15%	107%
WPD - South West	249	256	3%	251	1%	102%
WPD - South Wales	198	171	-14%	163	-18%	105%
EDF - LPN	282	537	90%	387	37%	139%
EDF - SPN	293	485	66%	414	41%	117%
EDF - EPN	475	852	79%	595	25%	143%
SP Distribution	296	396	34%	332	12%	119%
SP Manweb	285	464	63%	352	24%	132%
SSE - Hydro	171	206	21%	184	8%	112%
SSE - Southern	384	498	30%	498	30%	100%
Total	4,132	5,852	42%	5,043	22%	116%

Notes

1 DPCR3 RAV additions less meters and all faults. An adjustment for indirect costs capitalised, based on the 2002/03 normalisation adjustment has been made for comparability purposes - the issue of RAV roll forward and indirect costs is discussed earlier in the Chapter.

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.

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.

6.80. Table 6.7 shows the percentage change in the companies' DPCR4 forecasts compared to their DPCR3 actual/forecast spend and also the percentage difference between PB Power's view and actual/forecast spend this price control period. Table A9 in Appendix 1 shows how the adjusted DPCR4 forecasts have been calculated.

Comments on companies' forecasts

6.81. Most DNOs are suggesting that as their asset base becomes older the future level of capex will be higher than expenditure incurred during this price control period. On the basis set out in Table 6.7, six DNOs are suggesting increases of more than 40 per cent – with the highest at 90 per cent.

6.82. Review of DNOs' forecasts and PB Power's non-load related capex modelling supports some of the companies' forecasts – in other cases the forecasts have not been fully justified and some significant adjustments have been made. For eight of the DNOs, PB Power's view is within 10 per cent of the companies' own forecasts, and for five of these, it is within 5 per cent.

6.83. In total, after adjusting for exclusions and accounting differences, PB Power's views of capex requirements are around £800m lower than the companies' forecasts. Of this difference, around £500m relates to the EDF group of companies (LPN, EPN and SPN).

6.84. EDF appear to have taken a different approach to their forecasts than other companies. It claims that risk on their systems needs to be reduced from current levels and, particularly in EPN, they have to spend to increase available capacity. It has also included expenditure in their forecasts to manage what it sees as a cliff face of replacement in the future. Other companies do not see this cliff face and have not included such replacement in their forecasts.

6.85. It has been suggested by EDF that fluid filled cables may require significant early asset replacement during DPCR4 – although other DNOs do not share this view. EDF included around £155m in their forecasts to replace fluid filled cables. Following discussions with the company, Ofgem has excluded this from EDF's forecasts and is currently undertaking further analysis of this issue across all DNOs. Proposals for the appropriate treatment of fluid filled cables will be set out once this analysis has been completed.

Forecast Review Adjustments

6.86. A brief explanation of the differences between the adjusted DNO DPCR4 forecasts and PB Power's view is set out in Table 6.8.

Table 6.8: PB Power comments and adjustments

Company	Load related		Non load related		Total
	£m	Reason	£m	Reason	
CN – Midlands	17	Expenditure to reduce network risk to a level lower than DPCR3 has been removed as well as unsupported site-specific scheme.	28	Reduction in replacement activity (OHL) to maintain performance at base case level. Also limit set on LV Consac expenditure to industry levels.	45
CN – East Midlands	30	Inadequate support for reinforcement (switchgear). Risk of re-phasing of schemes to after 2010.	8	Reduction in forecast cable replacement and easement costs	38
United Utilities	15	Well supported forecast, reduced to level of modelled output.	1	Adequately supported forecast	16
CE – NEDL	-	Adequately supported forecast in keeping with modelled output	-	Adequately supported forecast in keeping with modelled output	0
CE – YEDL	10	Adequately supported submission but risk of re-phasing of schemes to after 2010 does exist.	11	Overall an adequately supported submission but risk of re-phasing of schemes to after 2010 does exist.	21
WPD – South West	-	Adequately supported forecast in keeping with modelled output.	5	Overall, with the exception of diversion related expenditure, an adequately supported forecast in keeping with modelled output .	5
WPD – South Wales	-	Adequately supported forecast in keeping with modelled output	8	Overall, with the exception of diversion related expenditure, an adequately supported forecast in keeping with modelled output .	8
EDF–LPN	93	Inadequate support for projects and financial provisions. Risk of rescoping and rephasing of projects.	57	Reduction to match asset replacement rates to industry norms.	150

EDF–SPN	50	Inadequate support for projects and financial provisions. Risk of rescoping and rephasing of projects.	21	Reduction to match asset replacement rates to industry norms. Unsupported increase in diversion expenditure.	71
EDF–EPN	162	Inadequate support for projects and financial provisions. Risk of rescoping and rephasing of projects.	96	Reduction to match asset replacement rates to industry norms. Reduction of SCADA expenditure.	257
SP Distribution	19	Reduction to DPCR3 level based on lack of supporting data to reinforce the submission and inability to reconcile forecast to a higher than DPCR3 expenditure level.	45	Reduction in underground cable replacement. Unsupported increase in diversion and SCADA expenditure.	64
SP Manweb	21	Reduction to DPCR3 level based on lack of supporting data to reinforce the submission and inability to reconcile forecast to a higher than DPCR3 expenditure level.	91	Reduction of replacement expenditure (switchgear) not adequately supported in terms of phasing. Reduction of increasing rate of cable replacement towards the end of DPCR4.	111
SSE – Hydro	-	Adequately supported forecast in keeping with modelled output	22	Reduction to match asset replacement rates to industry norms.	22
SSE – Southern	-	Adequately supported forecast in keeping with modelled output	-	Adequately supported forecast in keeping with modelled output	-

ESQCR

6.87. Companies have submitted widely varying costs relating to ESQCR compliance. For the purposes of this paper it has been difficult to estimate efficient cost levels and therefore ESQCR-related capex has therefore been excluded from the capex figures set out in this Chapter. Ofgem's intention is to allow companies to recover efficient costs in the next price control period. Ofgem will continue to review this issue in discussion with the DTI and the companies and will provide an update in the September document.

Setting capex allowances and investment incentives

6.88. The analysis explained above, including the work of PB Power, leads to some significant differences from the capex plans for a small number of DNOs – although for some companies, PB Power consider that a robust justification has been provided for the levels of expenditure that are being requested.

6.89. One option would be to set capex allowances on the basis of PB Power's view and if companies need to spend more they could request a re-opener of the price control. This approach may not provide appropriate incentives for efficient investment on any 'overspend'. Ofgem also recognises that there is inevitably some uncertainty about the level of capex that will be required in five or six years time to deliver the outputs that are required.

6.90. The March document also raised other important issues in relation to the incentives that companies may have under the existing capex arrangements – namely that they should not necessarily benefit from deferred investment where this is:

- derived from the regulatory process by companies submitting inflated capex forecasts;
- potentially at the expense of output delivery (including the longer term condition of the network); or
- achieved at the 'expense' of future expenditure.

6.91. Ofgem has been considering an alternative approach to setting capex allowances and incentives that seeks to address these issues. This involves using a 'sliding scale' mechanism where companies have different incentives depending on the level of their forecast compared to the PB Power view and more flexibility over actual expenditure.

6.92. The aims of the sliding scale mechanism are to:

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

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

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

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

Mechanics of the sliding scale approach

6.95. The mechanics of the approach rely on scaling all DNOs' capex forecasts relative to the view of PB Power of how much they are likely to need to spend – as set out in Table 6.7. For example, suppose PB Power's view is 100 – then:

- *for those companies with very high forecasts, say 140% of PB Power's view* - their allowance is set to 115% of the PB Power view. If they over or under spend the 115, they, get to keep or bear 20% of the difference - <u>i.e. the marginal incentive rate is 20%;</u>

- *for companies with fairly high forecasts, say 120% of PB Power's view* - their allowance is set at 110% (i.e. the difference between the company and PB Power view is split). If they over or under-spend the 110 they get to keep or bear 30% of any difference – <u>i.e. the marginal incentive rate is 30%.</u> To help ensure that if they do actually spend 120% (as they originally forecast) they are appropriately remunerated it is necessary to give them an additional amount of revenue (of '3'); and

- *for companies forecasting in line with PB Power's view* - their allowance is set at 105%. If they over or under-spend 105% they get to keep or bear 40% of any difference – <u>i.e. the marginal incentive rate is 40%.</u> They also are provided with an additional amount of revenue (of '5'). This ensures that, provided they spend close to or below 100%, they are better off then they would have been had they put in a higher forecast.

6.96. Table 6.9 shows a stylised version of the allowances and incentive rates for a range of forecast levels and then rewards (or penalties) for given out-turn actual expenditure.

Table 6.9: Stylised version of the sliding scale approach

DNO:PB Power ratio (%)	100	110	120	130	140
Marginal incentive.	40%	35%	30%	25%	20%
Additional revenue	5	4	2.8	1.5	0
Rewards and penalties:					
Allowed capex (%)	105	107.5	110	112.5	115
Actual capex					
70	**19**	17.1	14.8	12.1	9
80	**15**	13.6	11.8	9.6	7
90	**11**	10.1	8.8	7.1	5
100	**7**	6.6	5.8	4.6	3
105	**5**	4.9	4.3	3.4	2
110	3	**3.1**	2.8	2.1	1
115	1	**1.4**	1.3	0.9	0
120	-1	-0.4	**-0.3**	-0.4	-1
130	-5	-3.9	-3.3	**-2.9**	-3
140	-9	-7.4	-6.3	-5.4	**-5**

6.97. The important points from this table are that:

- the matrix is "incentive compatible" – the shaded boxes show the incentive compatible choice for various levels of actual spend. A company that actually spends 110, does best if it is in the "110" column – i.e. its forecast is to spend 110 – as seen from the value in that column (3.1) being higher than any other figure in that row;

- the scheme retains incentives for efficiency (rewards increase in each column moving up the table); and

- it allows high forecast companies to incur higher actual expenditure than the PB Power 100% view without (significant) penalty, up to a limit (i.e. the net penalties are small up to 120% in the table above).

6.98. Applying this concept would give all companies a higher capex allowance and return than if the PB Power view was used. This is shown in Table 6.10.

Table 6.10: Sliding scale allowance, return and incentive

DNO	Ratio of company forecast to PB Power view	Sliding scale (group basis)[1]	Sliding scale allowance (£m)[2]	Additional return (pre-tax)[3]	Marginal Incentive rate[4]
CN - Midlands	110%	107.5%	475	0.15%	35%
CN – East Midlands	109%	107.5%	450	0.15%	35%
United Utilities	104%	105%	461	0.2%	40%
CE – NEDL	100%	105%	266	0.2%	40%
CE – YEDL	107%	105%	329	0.2%	40%
WPD – South West	102%	105%	264	0.2%	40%
WPD – South Wales	105%	105%	171	0.2%	40%
EDF – LPN	139%	113.5%	439	0.03%	23%
EDF – SPN	117%	113.5%	470	0.03%	23%
EDF – EPN	143%	113.5%	675	0.03%	23%
SP Distribution	119%	111.5%	370	0.07%	27%
SP Manweb	132%	111.5%	393	0.07%	27%
SSE – Hydro	112%	105%	194	0.2%	40%
SSE – Southern	100%	105%	523	0.2%	40%
Total	116%	108.7%	5479	0.13%	
Increase from current price control			33%		

Notes:

1 In order to avoid perverse incentives it is necessary to put companies which are in the same ownership group together so that the marginal incentive rate is the same

2 This is derived from multiplying the PB Power view of capex by the sliding scale percentage in the second column

3 This is in addition to the assumed cost of capital of 6.6% pre-tax real

4 This is the percentage of each £1 saving of capex that is retained by companies. The incentive under the existing arrangements is 40%. Other percentage incentive rates can be achieved by varying the extent or duration for which the return and depreciation elements of underspend are retained.

6.99. It is possible to show the estimated rates of return that would be achieved by companies under this approach where they:

- spend what they forecast; and
- underspend their forecast by 10 per cent;
- spend their (sliding scale) allowance; and
- spend in line with PB Power's view.

6.100. This is shown in Table 6.11.

Table 6.11: Implied pre-tax real rates of return under the sliding scale mechanism

DNO	Actual spend = company forecast	Actual spend = company forecast less 10%	Actual spend = sliding scale allowance	Actual spend = PB Power view
CN – Midlands	6.7%	7.0%	6.8%	7.0%
CN – East Midlands	6.7%	7.0%	6.8%	7.0%
United Utilities	6.9%	7.3%	6.8%	7.0%
CE – NEDL	7.0%	7.3%	6.8%	7.0%
CE – YEDL	6.7%	7.0%	6.8%	6.9%
WPD – South West	6.9%	7.2%	6.8%	6.9%
WPD – South Wales	6.8%	7.0%	6.8%	6.9%
EDF – LPN	6.2%	6.4%	6.6%	6.9%
EDF – SPN	6.5%	6.9%	6.6%	7.0%
EDF – EPN	5.9%	6.3%	6.6%	6.9%
SP Distribution	6.6%	6.7%	6.7%	6.8%
SP Manweb	6.2%	6.5%	6.7%	7.0%
SSE – Hydro	6.7%	6.9%	6.8%	6.9%
SSE – Southern	6.9%	7.2%	6.8%	6.9%
Total	6.5%	6.8%	6.7%	6.9%

6.101. Using the sliding scale approach would therefore:

- imply a higher rate of return than the base cost of capital; and
- mean that Ofgem is setting the return companies receive for a given level of capex spend, rather than setting the actual level of capex spend.

6.102. There are some potential disadvantages of the sliding scale approach namely that:

- it is more complex than setting allowances equal to PB Power's view and not providing graduated incentives. This could give rise to unforeseen consequences; and
- there is some risk in giving strong incentives to low forecast companies (e.g. that they do not spend enough) and in weaker incentives on high forecast companies (e.g. if they are spending more money, it is all the more important that they spend it efficiently).

6.103. These initial proposals are based on the capex levels implied by the sliding scale approach. **Ofgem welcomes views on the sliding scale mechanism.**

6.104. Table 6.12 shows the capex allowances that are used in the price control calculations (Chapter 8).

Table 6.12: Capex allowances for initial proposals

DNO	Sliding scale allowance (£m)	Plus quality of supply capex (£m)	Less normal pensions (£m)[1]	Total allowed net capex (£m)	Annual allowed net capex (£m)
CN – Midlands	475	22	-15	482	96
CN – East Midlands	450	17	-13	454	91
United Utilities	461	0	-18	442	88
CE – NEDL	266	0	-11	255	51
CE – YEDL	329	4	-15	319	64
WPD – South West	264	0	-18	246	49
WPD – South Wales	171	6	-9	168	34
EDF – LPN	439	0	-15	425	85
EDF – SPN	470	13	-11	471	84
EDF – EPN	675	13	-29	659	132
SP Distribution	370	0	-21	349	70
SP Manweb	393	0	-18	375	75
SSE – Hydro	194	0	-9	185	37
SSE – Southern	523	25	-19	529	106
Total	5479	100	-221	5358	1072

Notes:

1 These costs have been excluded as they have been considered separately (Chapter 7). The PB Power view of capex in for DPCR4 in Table 6.7 already excluded pension deficit costs.

6.105. In addition, allowances for capitalised fault costs and non-operational capex are included in the price control (see Chapter 8).

6.106. For the purposes of price control modelling for initial proposals, Ofgem has spread the sliding scale and quality capex allowances equally across the five years 2005 to 2010. The appropriate profile to assume for capex within this period will be considered prior to final proposals.

Views invited

6.107. Views are particularly invited on:

- ♦ approach to assessing operating costs;
- ♦ roll-forward of the RAV; and

- assessment of capital expenditure and the proposed sliding scale mechanism.

7. Financial issues

Introduction

7.1. This Chapter sets out Ofgem's current position on a number of issues:

- the cost of capital;
- depreciation and asset lives;
- treatment of pension costs; and
- financial indicators.

7.2. As indicated in March, Ofgem intends to introduce a restriction on distributions for licensees that come close to losing investment grade credit ratings. The work on developing this mechanism will now be taken forward as part of the licence modification process for implementing the revised price controls.

Cost of capital

7.3. The cost of capital is the weighted average of the *expected* cost of debt and *expected* cost of equity. The March document explained that the allowed cost of capital under the existing price control (on a pre-tax basis) is 6.5 per cent. The range proposed by Ofgem for the next price control period is equivalent to 6 to 7.2 per cent pre-tax real. The proposed range reflects the strong investment focus of this review.

7.4. The cost of capital should be considered in a risk-return framework. If, as a result of changes to the regulatory regime, companies are exposed to more or less risk this would be reflected in a higher or lower cost of capital, as long as that risk would be considered to be non-diversifiable.

7.5. Ofgem's initial view on the issues raised by respondents to the March document is set out in the separate response to consultation Appendix.

Cost of capital for initial proposals

7.6. It is necessary to specify a figure for the cost of capital in order to carry out the price control calculations. This 'modelling assumption' does not represent a decision on the appropriate cost of capital. Ofgem expects to come to a decision about the cost of capital in final proposals in November.

7.7. The price control calculations are based on a modelling assumption of a pre-tax cost of debt of 4.1% and a post-tax cost of equity of 7.25%. Based on an assumed gearing level of 60% this translates in a pre-tax cost of capital of 6.6%, i.e. the mid-point of the cost of capital range proposed in the March document (6% to 7.2%). On a post-tax basis this translates to 4.6% and on a 'vanilla' WACC basis (i.e. without any tax adjustment to the cost of equity or cost of debt) this translates to 5.4%.

7.8. As explained in Chapter 6, the proposed sliding scale approach to capex allowances and incentives implies expected returns on capital higher than this base rate, of the order of 6.8 to 7.0 per cent pre-tax real for most of the companies depending on actual investment.

Tax and gearing

7.9. Ofgem has historically provided for tax liabilities through an allowance in its estimate of the pre-tax cost of capital. However, as discussed in previous documents, this review is using a post-tax approach to the cost of capital for this price control so the tax allowance has been calculated separately.

7.10. The tax allowance is based on the present corporation tax rate of 30% using Ofgem's forecast of profits chargeable to corporation tax. The tax allowances reflect the higher expected tax liabilities resulting from the ending of the non-load agreement which allowed most of the DNOs to claim 100 per cent allowances on a proportion of their capital expenditure. From 1 April 2005, it is likely that DNOs will only be able to claim an amount which is based on the accounting life of the assets, e.g. 2.5 per cent (assuming an average 40 year accounting life). The tax allowance included in these proposals fully reflects this change.

7.11. The other assumptions used to calculate the tax allowance are based on the companies' 2002/03 corporation tax computations. These, and the companies forecast tax charges for 2003/04 to 2009/10, were reviewed by Ernst & Young. Capitalised faults and non-operational capex are assumed to be opex for tax purposes as Ofgem has applied a general percentage to the amount of opex and total faults included in the RAV for 2005/06 to 2009/10 and the degree of capitalisation varies across companies. The other main assumption is that the amounts of expenditure that are assumed to be eligible for capital allowances are split between the various different capital allowance pools in accordance with each DNOs own tax computations for 2002/03. These assumptions will be reviewed for the September document as it is important that Ofgem's tax allowance represents a realistic view of the expected efficient tax liabilities for the next price control period.

7.12. The incentive payments[39] that companies will receive in DPCR4 have not been grossed up for tax because they are additional revenue in excess of the underlying costs of running the business. DPCR3 costs are also not allowed for tax in DPCR4 as companies will have already received the tax benefits of these costs in DPCR3.

7.13. Ofgem intends to base the estimated tax allowance on a company's actual gearing, or on the assumed gearing level for the cost of capital (i.e. 60%) if the latter is higher. For example, if a company has 40% gearing, its balance sheet will be adjusted to reflect a 60% gearing level and its estimated tax allowance will be based on the notional 60% gearing. However, if a company has 70% gearing, Ofgem intends to base its tax allowance on its actual gearing level (70%).

7.14. However, for the purposes of this paper only Ofgem has not reduced tax allowances for higher gearing. This adjustment will be incorporated as the tax projections are reviewed in the coming months.

[39] The tax treatment of payments that companies may receive under the distributed generation incentive mechanism is discussed in the supporting Appendix on distributed generation, IFI and RPZs, published alongside this document. This indicates that the appropriate tax allowance under the distributed generation incentive scheme is being considered.

Regulatory asset value and depreciation

7.15. The approach to depreciation that has been used for these initial proposals is consistent with the approach underlying the existing price controls. At the last price control review, some companies would have seen a large reduction in their depreciation allowance as Vesting assets[40] became fully depreciated (the so called depreciation "cliff-face"). An adjustment was made to smooth the depreciation allowance and a similar approach is proposed for this review.

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

7.17. Table 7.1 shows the assumed lives for Vesting assets.

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

Table 7.1: Vesting asset lives

DNO	Assumed Vesting asset life	Depreciation smoothing applied
CN – Midlands	15	from 2005/06
CN – East Midlands	15	from 2005/06
United Utilities	11	from 2001/02
CE – NEDL	14	from 2004/05
CE – YEDL	15	from 2005/06
WPD – South West	15	from 2005/06
WPD – South Wales	11	from 2001/02
EDF – LPN	15	from 2005/06
EDF – SPN	13	from 2003/04
EDF – EPN	14	from 2004/05
SP Distribution	20	n/a this price control period
SP Manweb	15	from 2005/06
SSE – Hydro	20	n/a this price control period
SSE – Southern	15	from 2005/06

Pensions

General

7.18. In previous documents, Ofgem has discussed its approach to pension costs. This approach involves applying the principles originally set out in the June 2003 paper on developing network price controls. The December 2003 document outlined the key practical issues involved in applying these principles in a methodology statement and this was updated in March 2004.

7.19. In these initial proposals, Ofgem has applied the approach set out in the March 2004 document. However, there are a number of issues still under consideration. The three main points are discussed below. In addition, this paper uses very preliminary estimates of the size of the deficit – further information will become available over the coming months. Ofgem will provide an update on the pension allowances in the September update paper.

Allocation between price-controlled and non-price-controlled activities

7.20. As explained in previous papers, Ofgem considers that price controls should only provide for the recovery of pension costs relating to the business that will be subject to the price control.

Under or over provision

7.21. The March 2004 document explained that, in principle, there should be an adjustment for over/under funding for both Early Retirement Deficiency Costs (ERDCs) and normal contributions. However as it is difficult to quantify what was allowed in previous price controls, Ofgem explained that it was not minded to make adjustments for over or under funding of normal contributions in relation to past price controls where the pension allowance was not separately identified.

ERDCs

7.22. The treatment of ERDCs is the main issue that is being raised by the companies. Essentially they argue that the way that ERDCs were to be treated at future price controls was not clear, and that they should be able to recover the associated pension costs in full from consumers. The companies also point out that consumers have benefited from the reduction in overall employment costs that have been achieved by those severances.

7.23. Some of the companies have suggested that, whilst they are opposed to the principle of Ofgem making any deduction for ERDCs, an alternative approach would be to consider the share of benefits between consumers and shareholders of the cost reductions associated with the severances. They suggest that, as consumers typically receive about 70% of the present value of benefit from a one off opex saving, then consumers should pay for 70% of the cost of the ERDCs - i.e. Ofgem should only disallow 30% of the ERDC element of the deficit.

7.24. Ofgem acknowledges that the treatment of these costs was not clear in previous price controls and that it was efficient for companies not to make contributions to the scheme that were not needed at the time, thereby effectively deferring the payment. The argument made by some of the companies to only disallow 30% of the deficit may have some merit. However, so does the argument set out in the March 2004 document for disallowing this element of the deficit.

7.25. As noted above, these initial proposals are based on the approach to pension costs outlined in the March document. Ofgem recognises that the treatment of costs associated with ERDCs has not been finalised and intends to reach a firm view on this for the September document.

Calculation of pensions allowances

7.26. The initial proposals for pension costs are set out in Table 7.2 and the detailed calculations are included in Table A10 in Appendix 1.

7.27. For these initial proposals, Ofgem has used the latest estimates provided by the companies of the pension deficits. Discussions with the companies suggest that the initial results of the March 2004 actuarial valuations will be available in time for the September document. It is hoped that near-final results from the valuations will be available for the final proposals paper in November, although this is dependent on the timetable of the Electricity Supply Pension Scheme (ESPS). The actuarial valuations of the two Scottish DNOs were completed as at March 2003 and show those schemes not to be in deficit.

7.28. For these initial proposals, based on the evidence to date, it is reasonable to use a figure of 80% for determining the distribution share of the overall deficit. For EDF - LPN and UU a lower figure has been used based on information received from the companies. For both EDF - EPN and YEDL it is assumed that the deficit is all distribution as it appears that only the distribution liabilities of EDF - EPN and YEDL were transferred when these companies were acquired by their present owners.

7.29. From this distribution deficit an amount is then deducted representing the extent to which ERDCs have contributed to the present deficits. This means that for the purpose of these initial proposals, the entire deficit related to ERDCs has been deducted. The remaining allowed pension deficit has then been spread over 13 years (the generally accepted estimate of average remaining service lives) to provide the annual amount of funding for those deficits.

7.30. It should be noted that no adjustment has been made to the estimates of ERDCs provided by the companies to reflect the investment returns that would have been earned had ERDCs been funded at the relevant retirement dates. Strict application of Ofgem's principles would require such adjustments to be made. It will be necessary to take this effect into account in determining the allowances for pension costs in Ofgem's final proposals.

7.31. The range of deficit funding requirements shown in Table 7.2 is wide. Ofgem has not reviewed the reasons for variations in the deficits (and has not yet considered stewardship issues as discussed in previous documents). Further consideration will be given to these issues and to incorporation of pension-related costs in the operating cost benchmarking.

Table 7.2: Allowed pension costs

DNO	Normal cost 2005/06	Normal cost 2006/07	Normal cost 2007/08	Normal cost 2008/09	Normal cost 2009/10	Deficit Recovery Per annum 2005/06 -	Total Allowance 2005/06	Total Allowance 2006/07	Total Allowance 2007/08	Total Allowance 2008/09	Total Allowance 2009/10
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
CN - Midlands	5.8	5.8	5.8	5.7	5.7	0.4	6.2	6.2	6.2	6.2	6.1
CN - East Midlands	4.4	4.4	4.5	4.4	4.4	4.9	9.3	9.3	9.3	9.3	9.3
United Utilities	6.5	6.5	6.4	6.4	6.3	1.0	7.5	7.5	7.4	7.3	7.3
CE - NEDL	3.9	3.9	3.9	3.9	3.9	1.3	5.2	5.2	5.2	5.2	5.1
CE - YEDL	4.8	4.8	4.8	4.8	4.8	1.4	6.3	6.2	6.2	6.2	6.2
WPD - South West	5.4	5.4	5.5	5.5	5.5	3.1	8.5	8.5	8.6	8.6	8.6
WPD - South Wales	2.7	2.7	2.8	2.7	2.7	2.8	5.4	5.4	5.5	5.5	5.5
EDF - LPN	5.5	5.6	5.6	5.6	5.7	9.7	15.2	15.3	15.3	15.3	15.4
EDF - SPN	3.9	3.9	3.9	4.0	4.0	3.4	7.3	7.4	7.4	7.4	7.4
EDF - EPN	7.1	7.1	7.2	7.4	7.5	2.5	9.5	9.6	9.7	9.8	10.0
SP Distribution	4.7	4.7	4.7	4.7	4.6	-	4.7	4.7	4.7	4.7	4.6
SP Manweb	3.8	3.9	3.8	3.8	3.8	8.1	11.9	12.0	11.9	11.9	11.9
SSE - Hydro	3.5	3.5	3.4	3.4	3.4	-	3.5	3.5	3.4	3.4	3.4
SSE - Southern	5.2	5.2	5.1	5.0	5.0	13.3	18.5	18.5	18.4	18.3	18.3
Total	**67.2**	**67.4**	**67.4**	**67.3**	**67.3**	51.9	**119.0**	**119.3**	**119.2**	**119.1**	**119.1**

Financial indicators

7.32. In setting the price control, Ofgem needs to ensure that companies can finance their activities. In addition to setting an appropriate cost of capital and other assumptions, Ofgem considers "financeability" by calculating and assessing certain financial ratios that are used by credit rating agencies and others in the financial community to assess the financial health of a company.

7.33. Ofgem has previously indicated that it intends to propose price controls that are consistent with companies maintaining credit ratings that are comfortably within investment grade.

7.34. Ofgem has considered a range of financial indicators. This assessment has been based on a model with initial gearing set in line with that used in the cost of capital assessment (i.e. 60%). For three indicators, test values have been used in assessing these initial proposals as follows:

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

7.35. Discussions with rating agencies indicate that these test values are conservative – some agencies have suggested less restrictive ratios on some measures. More fundamentally, all the agencies have noted that their ratings are based on broader assessments of a company and not just on a limited set of quantitative indicators.

7.36. Ofgem recognises that the three indicators described above do not fully capture the effects of capital expenditure requirements on free cash flow. Ofgem will discuss with the credit rating agencies and others in the financial markets how the changing capital expenditure profiles reflected in these initial proposals may be expected to affect perceptions of credit quality. Ofgem will take these discussions into account in determining its approach to the financeability checks in setting final proposals.

7.37. Nonetheless, it is reassuring that, based on the initial proposals, most of the companies exceed the test levels in all years from 2005 to 2010. In particular, those companies that are currently rated BBB+ appear to have substantially better ratios, implying that, on a standalone basis, these licensed entities have strong financial profiles.

7.38. For modelling purposes, Ofgem has used a dividend yield of 5 per cent, consistent with the cost of equity of 7.25 per cent and dividend growth in line with trend GDP growth.

7.39. Some of the companies come close to or across the test ratios in some years. However, with one exception, Ofgem's modelling to date does not appear to show a major financing issue.

7.40. The exception is EDF-SPN. This company combines a low starting RAV with relatively higher projections of capital expenditure. The financial modelling uses the "sliding scale" capex allowances – financial ratios would clearly be worse if EDF's own forecast of capital expenditure was used.

7.41. This leads to a question whether any adjustments to the price control proposals are warranted. At this stage, Ofgem has not made any such adjustments, not least because there is still a significant difference of view between Ofgem and the company on the size of the future capital expenditure programme.

7.42. However, Ofgem does not preclude making such adjustments in final proposals. In considering whether or not such adjustments are required, it is important to be aware of the potential means of improving financial ratios:

- increase revenues – set the price controls so that customers pay higher prices in the coming period (either via an additional cash allowance or a higher cost of capital for that company – both affecting only the company or companies with weak ratios);

- advance revenues – for example, by increasing depreciation (e.g. using shorter asset lives), customers will pay more in the coming five years, but correspondingly less in the longer term unless the problem recurs;

- increase equity – shareholders inject additional equity in the company (or forego dividends) to reduce debt and improve the financial position.

7.43. In considering whether to advance revenues, it is important to note that adjustments to depreciation have already been made or proposed for all the English and Welsh companies to mitigate the impact of pre-vesting depreciation ending as Vesting assets reach the end of their assumed lives. Asset lives used in the price control model are already much shorter than technical lives. Advancing revenues is necessarily a short-term solution.

7.44. Ofgem's initial view is that, particularly if only a small number of companies are affected and there is not a general financial constraint across the sector, it is reasonable to assume that, rather than allow credit quality to deteriorate, shareholders would provide additional equity in order to finance a proportion of the increased capital expenditures that are causing the strain, provided they have a reasonable prospect of receiving an appropriate return on this investment over time.

7.45. For some companies, Ofgem's modelling shows strong financial ratios – perhaps to the point where it would be possible to reduce prices in the period 2005-2010 by reducing depreciation allowances. The Scottish companies, in particular, have relatively high depreciation allowances as they are still receiving depreciation on pre-vesting assets through to the end of the review period. In principle, it would be possible to re-sculpt this pre-vesting depreciation. However, further assessment is required of the possible cashflow impact on these companies of investments to accommodate distributed generation before making any proposals in this area.

Views invited

7.46. Views are particularly invited on:

- the allowed pension costs and incorporation of pensions into the operating cost benchmarking; and

- the use of financial indicators including whether any adjustment should be made for companies with ratios below test levels and, if so, the form it should take.

8. Setting price controls

Introduction

8.1. This Chapter explains the way that the price controls have been set, including the key assumptions that have been adopted in order to derive an initial range for the level of allowed revenue for the next price control period.

The building blocks of the price control

8.2. Price controls provide a company with a level of revenue that is sufficient to finance an efficient business. This is based on an estimate of the various allowances that cover companies' costs and comprises:

- **operating expenditure** – this covers the day to day costs of running the network such as repairs and maintenance and generally most staff and overhead costs. In setting the price control an allowance is made to cover the level of operating expenditure which an efficient company would be expected to incur over the period of the price control (see Chapter 6);

- **capital expenditure** – including spending on assets, such as overhead line, underground cables and other plant, such as transformers. In setting the price control a projection is made of the level of capital expenditure that an efficient company would incur over the period of the price control. The benefits of capital expenditure are expected to last over several years so companies recover these costs over the assumed life of the asset, through an allowance for regulatory depreciation (see Chapter 6);

- **financing costs** – covers the costs an efficient company may be expected to incur in providing a reasonable return to the investors who provide the capital it requires – both debt and equity. The price control makes allowance for these costs by estimating a return on the value of the capital employed in the business (the regulatory asset value – RAV) equal to the return required by providers of finance - the cost of capital (see Chapter 7) ; and

- **taxation (corporation tax)**– the price control must provide sufficient cashflow to cover the tax liabilities that an efficient company may be expected to incur, taking into account the prevailing rate of corporation tax and the level of gearing used in estimating the cost of capital (see Chapter 7).

8.3. Setting the price control involves taking the total net present value (NPV) of the allowed costs and profiling total revenue to give the same total NPV.

The balance between 'P0' and 'X'

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

- the financial profile of companies – Ofgem has a duty to ensure that DNOs can finance their licensed activities. This is assessed by looking at the financial profile of the companies (see Chapter 7). This can be affected by how total price control revenue is profiled; and

- that the path of prices reflects cost trends and is sustainable – a given total of price control revenue can be achieved by different combinations of P0 and X – but the impact on the path of prices will be different. For instance, a large P0 cut followed by a low X would produce a higher final price than a modest P0 cut and a higher X.

8.5. Having considered these issues, Ofgem has used an X factor of 1 (i.e. RPI-1) for these initial proposals.

Price control calculations

8.6. The following tables set out how the price controls have been calculated for each DNO based on the approach outlined in each of the relevant Chapters of this document.

Key assumptions

8.7. Key assumptions that have been used to derive the price control assumptions are as follows:

- **value of X** – for the purposes of this paper this is assumed to take a value of 1, i.e. price control revenue will be allowed to increase by RPI-1 in each year from 2006/07 to 2009/10;
- **cost of equity** – the modelling assumption is 7.25 per cent post-tax real;
- **cost of debt** – the modelling assumption is 4.1 per cent pre-tax real;
- **metering** – costs associated with metering have been stripped out of other DNO costs consistent with the policy of setting separate price controls;
- **regulatory asset values (RAVs) and depreciation** – the opening RAV is consistent with the policy outlined in Chapter 6. The depreciation profiles are consistent with the assumptions and approach outlined in Chapter 7;
- **costs associated with excluded services** – most of the costs associated with the provision of excluded services are not included within allowed costs (e.g. non- trading rechargeables) so these costs relate only to other excluded service costs;
- **EHV costs** – consistent with the policy of including EHV consumers who are connected at 31 March 2005 within the price control, costs associated with those EHV consumers are included within allowed costs;

- **Hydro-Benefit** –the price control calculations for Scottish Hydro-Electric include no adjustment for the proposed replacement for Hydro-Benefit (Chapter 3); and

- **incentive scheme revenue** – it is assumed that, for the next price control, the incentive payments under the various incentive schemes, i.e:

  - losses;
  - quality of service; and
  - distributed generation, IFI and RPZ

  are equal to zero, i.e. no forecast is made of how companies will perform.

Capital expenditure

8.8. Line 1 shows the allowed level of load related capex and line 2 the allowed level of non-load related capex. Line 3 is gross base case capex and is the sum of lines 1 and 2.

8.9. Capital contributions (line 4) need to be deducted from gross base case capex to derive net base case capex in line 5 as they are outside the scope of the price controls.

8.10. Capitalised faults and non operational capex (line 6), the additional allowance for the sliding scale adjustment (line 7) and the quality of service allowance (line 8) are added to net base case capex in line 5 to give total net capex in line 9.

8.11. Capitalised fault costs and non operational capex equal 26% of opex excluding rates and pension costs. The 26% was calculated as the average amount of capitalised faults and non operational capex as a proportion of total "opex" (excluding rates and pensions costs) including all fault costs and non-operational capex as per the normalisation across the DNOs.

Calculating the RAV

8.12. The calculation of the RAV is shown in lines 10 to 13. In each year total net capex (line 11) is added to the opening RAV and the allowed level of depreciation (line 12) is subtracted from it to give a closing asset value (line 13). The closing value in any year then becomes the next year's opening value.

Calculating allowed costs

8.13. The allowed level of costs is shown in lines 14 to 22. Line 14 shows the allowed level of opex (excluding transmission exit charges). Table A5 in Appendix 1 provides an analysis of average opex over the price control period.

8.14. The allowed depreciation (line 15) is the same as in line 12.

8.15. The return on equity and debt (line 16) is calculated by multiplying the vanilla WACC (of 5.4 per cent) by the average of the opening and closing RAV (lines 10 and 13 respectively) in any year. The tax allowance is shown in line 17.

8.16. The capex incentive scheme (rolling retention of capex efficiencies in 2000-05) is given by line 18, the sliding scale additional income is shown in line 19, the quality of service additional revenue is in line 20 and costs incurred in the period 2000 to 2005 (DPCR3) which Ofgem has agreed to remunerate through the next price control are included in line 21.

8.17. The total level of allowed costs is given by line 22. The present value of these costs in each year is given by line 23. This is done by discounting the total allowed costs figure by the vanilla WACC of 5.4%. The total of these present values over 5 years is shown in line 24.

Calculating allowed revenue

8.18. In order to profile revenue, a revenue index is calculated based on companies' projections of growth in consumer numbers and units distributed, as shown in line 25. This is then discounted as for the total cost line, as shown in line 26.

8.19. Base price controlled revenue in line 27 is then derived by taking the total present value of allowed costs in line 24, deducting the present value of excluded services revenue for the period 2005/06 to 2009/10, dividing the result by the sum of the discounted revenue index in line 26 and then multiplying by the revenue index in line 25. The relevant items of excluded services revenue (those for which costs remain in the operating cost allowance in line 14) are included in line 28.

8.20. Total revenue is the sum of base price controlled revenue (line 27) and excluded services revenue (line 28) and is shown in line 29. The present value of line 29 is shown in line 30 and the total present value over 5 years is shown in line 31.

Calculating P0

8.21. Total price control revenue is allocated between P0 (line 32) and an X of one (line 33).

Breakdown of P0

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

8.23. Line 34 shows the effect on P0 of including charges to consumers connected to the network at the EHV level within the price control (see Chapter 3). Line 35 shows the effect on P0 of moving metering services and assets into a separate price control (see Chapter 3).

8.24. Line 36 shows the impact on P0 of changes in the opex allowance including efficiency savings already achieved by DNOs during this price control period, future efficiency targets and other opex assumptions (see Chapter 6 and Appendix 1).

8.25. Line 37 shows the impact of changes in depreciation resulting from the interaction of assumptions about asset lives (see Chapter 7). Line 38 shows the impact of increasing the cost of capital from 6.5 per cent pre-tax real to 6.6 per cent pre-tax real (see Chapter 7) and changes in the size of the RAV over time.

8.26. Line 39 shows the impact of changes to business rates resulting from the revised rateable valuations established by the VOA and the SAA (see Chapter 6). Line

40 shows the impact of changes to the expected level of efficient tax liabilities (see Chapter 7).

8.27. Line 41 shows the effect on P0 of other factors – these include the effect of spreading the base price control revenue evenly over the 5 years of the price control and that in 2004/05 companies have included expected payments under the losses incentive mechanism in their forecast revenue.

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
	CAPITAL EXPENDITURE						
1	Load related		48.0	48.0	48.0	48.0	48.0
2	Non load related		65.7	65.7	65.7	65.7	65.7
3	Gross base case capex		113.7	113.7	113.7	113.7	113.7
4	Capital contributions		(28.4)	(28.4)	(28.4)	(28.4)	(28.4)
5	Net base case capex		85.3	85.3	85.3	85.3	85.3
6	Capitalised faults and non op capex		15.1	14.9	14.6	14.4	14.1
7	Additional allowance		6.6	6.6	6.6	6.6	6.6
8	Quality of Service Allowance		4.5	4.5	4.5	4.5	4.5
9	**Total capex**		**111.5**	**111.3**	**111.0**	**110.8**	**110.5**
	RAV						
10	Opening asset value		930.4	970.2	1,007.6	1,039.2	1,064.9
11	Total capex		111.5	111.3	111.0	110.8	110.5
12	Depreciation		(71.7)	(73.9)	(79.5)	(85.0)	(90.6)
13	Closing asset value		970.2	1,007.6	1,039.2	1,064.9	1,084.9
	ALLOWED ITEMS						
14	Operating costs		71.6	69.7	68.3	67.5	66.7
15	Depreciation		71.7	73.9	79.5	85.0	90.6
16	Return		50.9	53.0	54.9	56.4	57.6
17	Tax allowance		23.2	23.2	22.8	22.3	21.8
18	Capex incentive scheme		2.7	2.5	2.9	2.6	1.2
19	Sliding scale additional income		1.4	1.5	1.5	1.6	1.6
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		0.8	-	-	-	-
22	**Total allowed costs**		**222.3**	**223.9**	**229.9**	**235.3**	**239.5**
23	Present value of allowed costs		216.6	207.0	201.8	196.0	189.3
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,010.8**
	REVENUE						
25	Revenue index		1.000	0.997	0.995	0.992	0.989
26	Discounted revenue index		0.974	0.922	0.873	0.826	0.782
27	**Price control revenue**	**243.9**	**228.0**	**227.4**	**226.8**	**226.1**	**225.4**
28	Excluded services revenue		2.9	2.9	2.9	2.9	2.9
29	Total revenue		230.9	230.3	229.7	229.0	228.3
30	Present value of total revenue		224.9	213.0	201.6	190.8	180.5
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,010.8**
32	PO		(6%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	1%					
35	Exclude metering	(1%)					
36	Change in Opex	(12%)					
37	Depreciation	(2%)					
38	Return	2%					
39	Rates	(1%)					
40	Tax	4%					
41	Other	2%					
42	**Total**	**(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.

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
	CAPITAL EXPENDITURE						
1	Load related		74.2	74.2	74.2	74.2	74.2
2	Non load related		49.2	49.2	49.2	49.2	49.2
3	Gross base case capex		123.4	123.4	123.4	123.4	123.4
4	Capital contributions		(42.4)	(42.4)	(42.4)	(42.4)	(42.4)
5	Net base case capex		81.0	81.0	81.0	81.0	81.0
6	Capitalised faults and non op capex		16.3	16.1	15.8	15.5	15.1
7	Additional allowance		6.3	6.3	6.3	6.3	6.3
8	Quality of Service Allowance		3.3	3.3	3.3	3.3	3.3
9	**Total capex**		**106.9**	**106.7**	**106.4**	**106.1**	**105.7**
	RAV						
10	Opening asset value		939.3	969.7	1,000.9	1,026.5	1,046.5
11	Total capex		106.9	106.7	106.4	106.1	105.7
12	Depreciation		(76.5)	(75.5)	(80.8)	(86.1)	(91.4)
13	Closing asset value		969.7	1,000.9	1,026.5	1,046.5	1,060.8
	ALLOWED ITEMS						
14	Operating costs		77.7	80.7	81.7	80.8	79.9
15	Depreciation		76.5	75.5	80.8	86.1	91.4
16	Return		51.2	52.8	54.3	55.6	56.5
17	Tax allowance		19.2	17.1	16.2	15.7	15.1
18	Capex incentive scheme		(0.3)	0.8	(0.5)	(0.7)	(0.2)
19	Sliding scale additional income		1.4	1.5	1.5	1.6	1.6
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		1.2	-	-	-	-
22	**Total allowed costs**		**226.9**	**228.4**	**234.0**	**239.0**	**244.3**
23	Present value of allowed costs		221.0	211.2	205.4	199.1	193.2
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,029.8**
	REVENUE						
25	Revenue index		1.000	0.999	1.000	1.002	1.003
26	Discounted revenue index		0.974	0.924	0.877	0.835	0.793
27	**Price control revenue**	**256.0**	**228.5**	**228.3**	**228.5**	**229.0**	**229.1**
28	Excluded services revenue		5.4	5.4	5.4	5.4	5.4
29	Total revenue		233.9	233.7	233.9	234.4	234.5
30	Present value of total revenue		227.9	216.1	205.2	195.2	185.4
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,029.8**
32	PO		(11%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	1%					
35	Exclude metering	(2%)					
36	Change in Opex	(5%)					
37	Depreciation	(3%)					
38	Return	2%					
39	Rates	1%					
40	Tax	2%					
41	Other	(7%)					
42	**Total**	**(11%)**					

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.

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
	CAPITAL EXPENDITURE						
1	Load related		42.7	42.7	42.7	42.7	42.7
2	Non load related		56.9	56.9	56.9	56.9	56.9
3	Gross base case capex		99.6	99.6	99.6	99.6	99.6
4	Capital contributions		(15.6)	(15.6)	(15.6)	(15.6)	(15.6)
5	Net base case capex		84.0	84.0	84.0	84.0	84.0
6	Capitalised faults and non op capex		14.4	14.1	13.9	13.6	13.4
7	Additional allowance		4.4	4.4	4.4	4.4	4.4
8	Quality of Service Allowance		-	-	-	-	-
9	**Total capex**		**102.8**	**102.5**	**102.3**	**102.0**	**101.8**
	RAV						
10	Opening asset value		859.8	897.6	929.9	956.9	978.5
11	Total capex		102.8	102.5	102.3	102.0	101.8
12	Depreciation		(65.0)	(70.2)	(75.3)	(80.4)	(85.5)
13	Closing asset value		897.6	929.9	956.9	978.5	994.8
	ALLOWED ITEMS						
14	Operating costs		66.8	65.1	64.2	63.4	62.7
15	Depreciation		65.0	70.2	75.3	80.4	85.5
16	Return		47.1	49.0	50.6	51.9	52.9
17	Tax allowance		13.2	16.2	16.6	16.7	16.4
18	Capex incentive scheme		6.6	5.4	3.2	2.0	1.0
19	Sliding scale additional income		1.8	1.8	1.9	1.9	2.0
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		1.3	-	-	-	-
22	**Total allowed costs**		**201.7**	**207.6**	**211.8**	**216.3**	**220.5**
23	Present value of allowed costs		196.5	192.0	185.8	180.2	174.3
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**928.8**
	REVENUE						
25	Revenue index		1.000	1.001	0.993	0.992	0.984
26	Discounted revenue index		0.974	0.925	0.871	0.826	0.778
27	**Price control revenue**	**205.7**	**201.9**	**202.1**	**200.5**	**200.3**	**198.6**
28	Excluded services revenue		10.3	10.3	10.3	10.3	10.3
29	Total revenue		212.2	212.4	210.8	210.6	208.9
30	Present value of total revenue		206.8	196.4	185.0	175.4	165.2
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**928.8**
32	PO		(2%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	2%					
35	Exclude metering	(1%)					
36	Change in Opex	(12%)					
37	Depreciation	6%					
38	Return	1%					
39	Rates	1%					
40	Tax	2%					
41	Other	0%					
42	**Total**	**(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.

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
	CAPITAL EXPENDITURE						
1	Load related		37.4	37.4	37.4	37.4	37.4
2	Non load related		37.6	37.6	37.6	37.6	37.6
3	Gross base case capex		75.0	75.0	75.0	75.0	75.0
4	Capital contributions		(26.5)	(26.5)	(26.5)	(26.5)	(26.5)
5	Net base case capex		48.5	48.5	48.5	48.5	48.5
6	Capitalised faults and non op capex		10.9	10.8	10.5	10.4	10.2
7	Additional allowance		2.5	2.5	2.5	2.5	2.5
8	Quality of Service Allowance		-	-	-	-	-
9	**Total capex**		**61.9**	**61.8**	**61.5**	**61.4**	**61.2**
	RAV						
10	Opening asset value		558.2	577.9	594.4	607.4	617.4
11	Total capex		61.9	61.8	61.5	61.4	61.2
12	Depreciation		(42.2)	(45.3)	(48.4)	(51.5)	(54.6)
13	Closing asset value		577.9	594.4	607.4	617.4	624.0
	ALLOWED ITEMS						
14	Operating costs		48.2	49.5	49.0	48.4	47.9
15	Depreciation		42.2	45.3	48.4	51.5	54.6
16	Return		30.4	31.4	32.2	32.8	33.3
17	Tax allowance		11.3	11.0	11.0	11.3	11.7
18	Capex incentive scheme		5.0	4.2	3.8	2.9	1.3
19	Sliding scale additional income		-	-	-	-	-
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		1.7	-	-	-	-
22	**Total allowed costs**		**138.9**	**141.4**	**144.5**	**146.9**	**148.7**
23	Present value of allowed costs		135.3	130.8	126.8	122.3	117.5
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**632.7**
	REVENUE						
25	Revenue index		1.000	1.004	1.007	1.011	1.014
26	Discounted revenue index		0.974	0.928	0.884	0.842	0.802
27	**Price control revenue**	**157.5**	**139.3**	**139.9**	**140.4**	**140.9**	**141.3**
28	Excluded services revenue		3.5	3.5	3.5	3.5	3.5
29	Total revenue		142.8	143.4	143.9	144.4	144.8
30	Present value of total revenue		139.2	132.6	126.3	120.2	114.5
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**632.7**
32	PO		(12%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	6%					
35	Exclude metering	(1%)					
36	Change in Opex	(16%)					
37	Depreciation	3%					
38	Return	0%					
39	Rates	1%					
40	Tax	2%					
41	Other	(7%)					
42	**Total**	**(12%)**					

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.

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
	CAPITAL EXPENDITURE						
1	Load related		53.4	53.4	53.4	53.4	53.4
2	Non load related		46.5	46.5	46.5	46.5	46.5
3	Gross base case capex		99.9	99.9	99.9	99.9	99.9
4	Capital contributions		(40.1)	(40.1)	(40.1)	(40.1)	(40.1)
5	Net base case capex		59.8	59.8	59.8	59.8	59.8
6	Capitalised faults and non op capex		13.2	12.9	12.7	12.5	12.2
7	Additional allowance		3.1	3.1	3.1	3.1	3.1
8	Quality of Service Allowance		0.8	0.8	0.8	0.8	0.8
9	**Total capex**		**76.9**	**76.6**	**76.4**	**76.2**	**75.9**
	RAV						
10	Opening asset value		804.0	813.5	828.7	839.9	847.2
11	Total capex		76.9	76.6	76.4	76.2	75.9
12	Depreciation		(67.4)	(61.4)	(65.2)	(68.9)	(72.7)
13	Closing asset value		813.5	828.7	839.9	847.2	850.4
	ALLOWED ITEMS						
14	Operating costs		64.3	62.5	61.0	60.0	59.3
15	Depreciation		67.4	61.4	65.2	68.9	72.7
16	Return		43.4	44.0	44.6	45.1	45.3
17	Tax allowance		15.6	17.0	17.7	18.0	18.2
18	Capex incentive scheme		1.3	(0.1)	(2.2)	(2.3)	(1.3)
19	Sliding scale additional income		1.6	1.6	1.7	1.7	1.7
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		0.9	-	-	-	-
22	**Total allowed costs**		**194.5**	**186.4**	**188.0**	**191.4**	**195.9**
23	Present value of allowed costs		189.5	172.4	165.0	159.4	154.9
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**841.2**
	REVENUE						
25	Revenue index		1.000	1.000	1.000	1.000	1.000
26	Discounted revenue index		0.974	0.925	0.877	0.833	0.790
27	**Price control revenue**	**218.9**	**186.5**	**186.5**	**186.5**	**186.5**	**186.4**
28	Excluded services revenue		4.7	4.7	4.7	4.7	4.7
29	Total revenue		191.2	191.2	191.2	191.2	191.1
30	Present value of total revenue		186.3	176.8	167.8	159.2	151.1
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**841.2**
32	PO		(15%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	2%					
35	Exclude metering	(2%)					
36	Change in Opex	(8%)					
37	Depreciation	(7%)					
38	Return	0%					
39	Rates	(1%)					
40	Tax	3%					
41	Other	(3%)					
42	**Total**	**(15%)**					

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.

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
	CAPITAL EXPENDITURE						
1	Load related		29.2	29.2	29.2	29.2	29.2
2	Non load related		33.4	33.4	33.4	33.4	33.4
3	Gross base case capex		62.6	62.6	62.6	62.6	62.6
4	Capital contributions		(15.9)	(15.9)	(15.9)	(15.9)	(15.9)
5	Net base case capex		46.7	46.7	46.7	46.7	46.7
6	Capitalised faults and non op capex		12.4	12.2	12.0	11.8	11.6
7	Additional allowance		2.5	2.5	2.5	2.5	2.5
8	Quality of Service Allowance		-	-	-	-	-
9	**Total capex**		**61.6**	**61.4**	**61.2**	**61.0**	**60.8**
	RAV						
10	Opening asset value		717.6	727.9	733.0	734.8	733.3
11	Total capex		61.6	61.4	61.2	61.0	60.8
12	Depreciation		(51.3)	(56.3)	(59.4)	(62.5)	(65.5)
13	Closing asset value		727.9	733.0	734.8	733.3	728.6
	ALLOWED ITEMS						
14	Operating costs		58.3	60.2	61.0	60.4	59.8
15	Depreciation		51.3	56.3	59.4	62.5	65.5
16	Return		38.7	39.2	39.3	39.3	39.2
17	Tax allowance		14.1	13.7	13.7	14.1	14.5
18	Capex incentive scheme		2.9	3.0	2.2	1.3	0.5
19	Sliding scale additional income		1.4	1.5	1.5	1.5	1.5
20	Quality incentive		1.7	1.7	1.7	1.7	1.7
21	DPCR3 costs		1.5	-	-	-	-
22	**Total allowed costs**		**169.9**	**175.5**	**178.8**	**180.8**	**182.7**
23	Present value of allowed costs		165.6	162.3	157.0	150.6	144.4
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**779.8**
	REVENUE						
25	Revenue index		1.000	1.003	1.006	1.007	1.010
26	Discounted revenue index		0.974	0.927	0.883	0.839	0.798
27	**Price control revenue**	**169.9**	**169.5**	**169.9**	**170.5**	**170.7**	**171.2**
28	Excluded services revenue		6.9	6.9	6.9	6.9	6.9
29	Total revenue		176.4	176.8	177.4	177.6	178.1
30	Present value of total revenue		171.8	163.5	155.7	148.0	140.8
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**779.8**
32	PO		(0%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	2%					
35	Exclude metering	(2%)					
36	Change in Opex	(7%)					
37	Depreciation	(1%)					
38	Return	0%					
39	Rates	1%					
40	Tax	3%					
41	Other	5%					
42	**Total**	**(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.

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
	CAPITAL EXPENDITURE						
1	Load related		19.8	19.8	19.8	19.8	19.8
2	Non load related		21.2	21.2	21.2	21.2	21.2
3	Gross base case capex		41.0	41.0	41.0	41.0	41.0
4	Capital contributions		(10.2)	(10.2)	(10.2)	(10.2)	(10.2)
5	Net base case capex		30.8	30.8	30.8	30.8	30.8
6	Capitalised faults and non op capex		10.2	10.1	9.8	9.7	9.6
7	Additional allowance		1.6	1.6	1.6	1.6	1.6
8	Quality of Service Allowance		1.2	1.2	1.2	1.2	1.2
9	**Total capex**		**43.8**	**43.7**	**43.4**	**43.3**	**43.2**
	RAV						
10	Opening asset value		573.9	572.1	568.0	561.4	552.5
11	Total capex		43.8	43.7	43.4	43.3	43.2
12	Depreciation		(45.7)	(47.9)	(50.0)	(52.2)	(54.4)
13	Closing asset value		572.1	568.0	561.4	552.5	541.4
	ALLOWED ITEMS						
14	Operating costs		45.4	46.8	47.5	47.0	46.5
15	Depreciation		45.7	47.9	50.0	52.2	54.4
16	Return		30.7	30.5	30.3	29.8	29.3
17	Tax allowance		11.1	11.3	12.2	12.7	13.1
18	Capex incentive scheme		(2.0)	(1.0)	(0.3)	0.1	0.1
19	Sliding scale additional income		1.1	1.1	1.1	1.1	1.1
20	Quality incentive		1.3	1.3	1.3	1.3	1.3
21	DPCR3 costs		0.8	-	-	-	-
22	**Total allowed costs**		**134.1**	**138.0**	**142.1**	**144.2**	**145.8**
23	Present value of allowed costs		130.6	127.6	124.7	120.1	115.3
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**618.4**
	REVENUE						
25	Revenue index		1.000	1.002	1.006	1.006	1.009
26	Discounted revenue index		0.974	0.927	0.883	0.838	0.797
27	**Price control revenue**	**133.5**	**135.7**	**136.1**	**136.5**	**136.6**	**136.9**
28	Excluded services revenue		4.2	4.2	4.2	4.2	4.2
29	Total revenue		139.9	140.3	140.7	140.8	141.1
30	Present value of total revenue		136.3	129.7	123.5	117.3	111.5
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**618.4**
32	PO		2%				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	7%					
35	Exclude metering	(2%)					
36	Change in Opex	(8%)					
37	Depreciation	6%					
38	Return	1%					
39	Rates	1%					
40	Tax	4%					
41	Other	(6%)					
42	**Total**	**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.

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
	CAPITAL EXPENDITURE						
1	Load related		53.0	53.0	53.0	53.0	53.0
2	Non load related		57.4	57.4	57.4	57.4	57.4
3	Gross base case capex		110.4	110.4	110.4	110.4	110.4
4	Capital contributions		(35.9)	(35.9)	(35.9)	(35.9)	(35.9)
5	Net base case capex		74.5	74.5	74.5	74.5	74.5
6	Capitalised faults and non op capex		13.0	12.8	12.5	12.3	12.1
7	Additional allowance		10.5	10.5	10.5	10.5	10.5
8	Quality of Service Allowance		-	-	-	-	-
9	**Total capex**		**98.0**	**97.8**	**97.5**	**97.3**	**97.1**
	RAV						
10	Opening asset value		922.2	951.4	976.7	996.8	1,011.9
11	Total capex		98.0	97.8	97.5	97.3	97.1
12	Depreciation		(68.8)	(72.5)	(77.4)	(82.3)	(87.1)
13	Closing asset value		951.4	976.7	996.8	1,011.9	1,021.9
	ALLOWED ITEMS						
14	Operating costs		70.4	72.9	74.3	73.7	73.0
15	Depreciation		68.8	72.5	77.4	82.3	87.1
16	Return		50.2	51.7	52.9	53.8	54.5
17	Tax allowance		22.7	21.7	21.7	21.8	22.1
18	Capex incentive scheme		6.2	6.0	3.4	2.2	0.8
19	Sliding scale additional income		0.3	0.3	0.3	0.3	0.3
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		3.7	-	-	-	-
22	**Total allowed costs**		**222.3**	**225.1**	**229.9**	**234.1**	**237.8**
23	Present value of allowed costs		216.6	208.1	201.8	195.0	188.0
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,009.5**
	REVENUE						
25	Revenue index		1.000	1.005	1.010	1.016	1.021
26	Discounted revenue index		0.974	0.930	0.887	0.846	0.807
27	**Price control revenue**	**227.1**	**221.5**	**222.7**	**223.8**	**225.0**	**226.2**
28	Excluded services revenue		5.7	5.7	5.7	5.7	5.7
29	Total revenue		227.2	228.4	229.5	230.7	231.9
30	Present value of total revenue		221.4	211.2	201.4	192.1	183.3
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,009.5**
32	PO		(2%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	2%					
35	Exclude metering	0%					
36	Change in Opex	(6%)					
37	Depreciation	(2%)					
38	Return	0%					
39	Rates	1%					
40	Tax	4%					
41	Other	(1%)					
42	**Total**	**(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.

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
	CAPITAL EXPENDITURE						
1	Load related		40.1	40.1	40.1	40.1	40.1
2	Non load related		62.1	62.1	62.1	62.1	62.1
3	Gross base case capex		102.2	102.2	102.2	102.2	102.2
4	Capital contributions		(21.7)	(21.7)	(21.7)	(21.7)	(21.7)
5	Net base case capex		80.5	80.5	80.5	80.5	80.5
6	Capitalised faults and non op capex		13.0	12.7	12.5	12.2	12.0
7	Additional allowance		11.2	11.2	11.2	11.2	11.2
8	Quality of Service Allowance		2.6	2.6	2.6	2.6	2.6
9	**Total capex**		**107.3**	**107.0**	**106.8**	**106.5**	**106.3**
	RAV						
10	Opening asset value		651.0	711.1	765.4	814.3	857.5
11	Total capex		107.3	107.0	106.8	106.5	106.3
12	Depreciation		(47.2)	(52.6)	(58.0)	(63.3)	(68.7)
13	Closing asset value		711.1	765.4	814.3	857.5	895.1
	ALLOWED ITEMS						
14	Operating costs		58.4	57.0	55.7	53.1	48.6
15	Depreciation		47.2	52.6	58.0	63.3	68.7
16	Return		36.5	39.6	42.4	44.8	47.0
17	Tax allowance		10.1	8.9	7.7	6.7	6.2
18	Capex incentive scheme		(5.3)	(5.7)	(4.9)	(4.4)	(2.7)
19	Sliding scale additional income		0.2	0.2	0.2	0.3	0.3
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		1.0	-	-	-	-
22	**Total allowed costs**		**148.1**	**152.6**	**159.0**	**163.8**	**168.1**
23	Present value of allowed costs		144.3	141.1	139.6	136.4	132.9
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**694.3**
	REVENUE						
25	Revenue index		1.000	0.999	0.998	0.997	0.996
26	Discounted revenue index		0.974	0.924	0.876	0.830	0.787
27	**Price control revenue**	**156.0**	**150.4**	**150.2**	**150.1**	**149.9**	**149.8**
28	Excluded services revenue		7.7	7.7	7.7	7.7	7.7
29	Total revenue		158.1	157.9	157.8	157.6	157.5
30	Present value of total revenue		154.0	146.0	138.5	131.3	124.5
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**694.3**
32	PO		(4%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	5%					
35	Exclude metering	(4%)					
36	Change in Opex	(14%)					
37	Depreciation	11%					
38	Return	7%					
39	Rates	(1%)					
40	Tax	(0%)					
41	Other	(7%)					
42	**Total**	**(4%)**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs 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.

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
	CAPITAL EXPENDITURE						
1	Load related		85.2	85.2	85.2	85.2	85.2
2	Non load related		78.8	78.8	78.8	78.8	78.8
3	Gross base case capex		164.0	164.0	164.0	164.0	164.0
4	Capital contributions		(50.8)	(50.8)	(50.8)	(50.8)	(50.8)
5	Net base case capex		113.2	113.2	113.2	113.2	113.2
6	Capitalised faults and non op capex		20.9	20.5	20.1	19.8	19.5
7	Additional allowance		16.1	16.1	16.1	16.1	16.1
8	Quality of Service Allowance		2.7	2.7	2.7	2.7	2.7
9	**Total capex**		**152.9**	**152.5**	**152.1**	**151.8**	**151.5**
	RAV						
10	Opening asset value		1,151.3	1,222.4	1,285.5	1,340.6	1,387.8
11	Total capex		152.9	152.5	152.1	151.8	151.5
12	Depreciation		(81.7)	(89.4)	(97.0)	(104.6)	(112.2)
13	Closing asset value		1,222.4	1,285.5	1,340.6	1,387.8	1,427.1
	ALLOWED ITEMS						
14	Operating costs		93.5	93.9	92.9	92.0	91.2
15	Depreciation		81.7	89.4	97.0	104.6	112.2
16	Return		63.6	67.2	70.4	73.1	75.4
17	Tax allowance		16.3	17.3	18.1	18.7	18.3
18	Capex incentive scheme		9.9	7.4	4.2	0.8	(0.2)
19	Sliding scale additional income		0.4	0.4	0.4	0.4	0.4
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		1.6	-	-	-	-
22	**Total allowed costs**		**267.1**	**275.6**	**283.0**	**289.7**	**297.4**
23	Present value of allowed costs		260.2	254.9	248.3	241.3	235.1
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,239.8**
	REVENUE						
25	Revenue index		1.000	1.001	1.001	1.001	1.001
26	Discounted revenue index		0.974	0.925	0.878	0.834	0.791
27	**Price control revenue**	**291.6**	**278.3**	**278.5**	**278.5**	**278.5**	**278.5**
28	Excluded services revenue		3.3	3.3	3.3	3.3	3.3
29	Total revenue		281.6	281.8	281.8	281.8	281.8
30	Present value of total revenue		274.4	260.6	247.3	234.7	222.8
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,239.8**
32	PO		(5%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	2%					
35	Exclude metering	(3%)					
36	Change in Opex	(1%)					
37	Depreciation	(1%)					
38	Return	1%					
39	Rates	1%					
40	Tax	0%					
41	Other	(4%)					
42	**Total**	**(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.

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
	CAPITAL EXPENDITURE						
1	Load related		48.6	48.6	48.6	48.6	48.6
2	Non load related		41.6	41.6	41.6	41.6	41.6
3	Gross base case capex		90.2	90.2	90.2	90.2	90.2
4	Capital contributions		(27.9)	(27.9)	(27.9)	(27.9)	(27.9)
5	Net base case capex		62.3	62.3	62.3	62.3	62.3
6	Capitalised faults and non op capex		14.2	13.9	13.7	13.4	13.2
7	Additional allowance		7.6	7.6	7.6	7.6	7.6
8	Quality of Service Allowance		-	-	-	-	-
9	**Total capex**		**84.1**	**83.8**	**83.6**	**83.3**	**83.1**
	RAV						
10	Opening asset value		1,288.8	1,262.5	1,233.6	1,202.3	1,168.6
11	Total capex		84.1	83.8	83.6	83.3	83.1
12	Depreciation		(110.4)	(112.7)	(114.9)	(117.1)	(119.3)
13	Closing asset value		1,262.5	1,233.6	1,202.3	1,168.6	1,132.4
	ALLOWED ITEMS						
14	Operating costs		73.6	77.8	77.1	76.3	75.6
15	Depreciation		110.4	112.7	114.9	117.1	119.3
16	Return		68.4	66.9	65.3	63.5	61.7
17	Tax allowance		28.9	28.9	30.1	31.1	31.9
18	Capex incentive scheme		(6.9)	(5.9)	(3.8)	(1.1)	0.5
19	Sliding scale additional income		0.9	0.9	0.9	0.8	0.8
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		1.3	-	-	-	-
22	**Total allowed costs**		**276.6**	**281.2**	**284.4**	**287.8**	**289.7**
23	Present value of allowed costs		269.5	260.1	249.6	239.8	229.1
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,248.0**
	REVENUE						
25	Revenue index		1.000	0.998	0.995	0.993	0.991
26	Discounted revenue index		0.974	0.922	0.873	0.827	0.783
27	**Price control revenue**	**263.0**	**284.9**	**284.2**	**283.5**	**282.9**	**282.2**
28	Excluded services revenue		-	-	-	-	-
29	Total revenue		284.9	284.2	283.5	282.9	282.2
30	Present value of total revenue		277.6	262.8	248.8	235.6	223.1
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,248.0**
32	PO		8%				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	0%					
35	Exclude metering	(2%)					
36	Change in Opex	(2%)					
37	Depreciation	3%					
38	Return	(0%)					
39	Rates	4%					
40	Tax	5%					
41	Other	0%					
42	**Total**	**8%**					

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.

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
	CAPITAL EXPENDITURE						
1	Load related		41.2	41.2	41.2	41.2	41.2
2	Non load related		43.0	43.0	43.0	43.0	43.0
3	Gross base case capex		84.2	84.2	84.2	84.2	84.2
4	Capital contributions		(17.4)	(17.4)	(17.4)	(17.4)	(17.4)
5	Net base case capex		66.8	66.8	66.8	66.8	66.8
6	Capitalised faults and non op capex		11.7	11.5	11.3	11.1	10.9
7	Additional allowance		8.1	8.1	8.1	8.1	8.1
8	Quality of Service Allowance		-	-	-	-	-
9	**Total capex**		**86.6**	**86.4**	**86.2**	**86.0**	**85.8**
	RAV						
10	Opening asset value		747.4	781.6	809.8	833.5	852.7
11	Total capex		86.6	86.4	86.2	86.0	85.8
12	Depreciation		(52.4)	(58.2)	(62.5)	(66.8)	(71.1)
13	Closing asset value		781.6	809.8	833.5	852.7	867.4
	ALLOWED ITEMS						
14	Operating costs		59.5	58.3	56.9	55.1	54.6
15	Depreciation		52.4	58.2	62.5	66.8	71.1
16	Return		41.0	42.6	44.0	45.2	46.1
17	Tax allowance		13.5	12.8	12.2	11.8	11.0
18	Capex incentive scheme		(2.7)	(4.7)	(4.5)	(3.1)	(2.1)
19	Sliding scale additional income		0.5	0.6	0.6	0.6	0.6
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		0.8	-	-	-	-
22	**Total allowed costs**		**165.0**	**167.8**	**171.7**	**176.3**	**181.3**
23	Present value of allowed costs		160.7	155.1	150.7	146.9	143.3
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**756.8**
	REVENUE						
25	Revenue index		1.000	0.998	0.997	0.995	0.994
26	Discounted revenue index		0.974	0.923	0.875	0.829	0.786
27	**Price control revenue**	**163.0**	**169.5**	**169.2**	**168.9**	**168.7**	**168.5**
28	Excluded services revenue		3.0	3.0	3.0	3.0	3.0
29	Total revenue		172.5	172.2	171.9	171.7	171.5
30	Present value of total revenue		168.1	159.2	150.9	143.0	135.6
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**756.8**
32	PO		4%				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	5%					
35	Exclude metering	(1%)					
36	Change in Opex	(2%)					
37	Depreciation	2%					
38	Return	4%					
39	Rates	(1%)					
40	Tax	2%					
41	Other	(4%)					
42	**Total**	**4%**					

Notes:
1. Price control revenue excludes metering as this is included in the metering price control but includes EHV on pre March 2005 assets.
2. Operating costs 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.

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
	CAPITAL EXPENDITURE						
1	Load related		21.8	21.8	21.8	21.8	21.8
2	Non load related		24.9	24.9	24.9	24.9	24.9
3	Gross base case capex		46.7	46.7	46.7	46.7	46.7
4	Capital contributions		(11.6)	(11.6)	(11.6)	(11.6)	(11.6)
5	Net base case capex		35.1	35.1	35.1	35.1	35.1
6	Capitalised faults and non op capex		9.7	9.5	9.4	9.2	9.0
7	Additional allowance		1.8	1.8	1.8	1.8	1.8
8	Quality of Service Allowance		-	-	-	-	-
9	**Total capex**		**46.6**	**46.4**	**46.3**	**46.1**	**45.9**
	RAV						
10	Opening asset value		727.1	723.1	717.7	711.0	702.8
11	Total capex		46.6	46.4	46.3	46.1	45.9
12	Depreciation		(50.6)	(51.8)	(53.0)	(54.3)	(55.5)
13	Closing asset value		723.1	717.7	711.0	702.8	693.3
	ALLOWED ITEMS						
14	Operating costs		40.8	41.9	43.3	44.3	43.8
15	Depreciation		50.6	51.8	53.0	54.3	55.5
16	Return		38.9	38.6	38.3	37.9	37.4
17	Tax allowance		17.3	17.5	17.7	18.2	19.1
18	Capex incentive scheme		6.5	5.8	4.5	2.7	1.0
19	Sliding scale additional income		1.5	1.4	1.4	1.4	1.4
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		0.8	-	-	-	-
22	**Total allowed costs**		**156.2**	**157.1**	**158.3**	**158.7**	**158.1**
23	Present value of allowed costs		152.2	145.2	138.9	132.2	125.0
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**693.5**
	REVENUE						
25	Revenue index		1.000	1.000	1.000	1.000	0.999
26	Discounted revenue index		0.974	0.925	0.877	0.833	0.790
27	**Price control revenue**	**157.3**	**157.3**	**157.2**	**157.2**	**157.2**	**157.2**
28	Excluded services revenue		0.4	0.4	0.4	0.4	0.4
29	Total revenue		157.7	157.6	157.6	157.6	157.6
30	Present value of total revenue		153.6	145.8	138.3	131.3	124.6
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**693.5**
32	PO		(0%)				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	1%					
35	Exclude metering	(2%)					
36	Change in Opex	(9%)					
37	Depreciation	1%					
38	Return	(2%)					
39	Rates	1%					
40	Tax	5%					
41	Other	5%					
42	**Total**	**(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.

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
	CAPITAL EXPENDITURE						
1	Load related		67.9	67.9	67.9	67.9	67.9
2	Non load related		58.2	58.2	58.2	58.2	58.2
3	Gross base case capex		126.1	126.1	126.1	126.1	126.1
4	Capital contributions		(30.3)	(30.3)	(30.3)	(30.3)	(30.3)
5	Net base case capex		95.8	95.8	95.8	95.8	95.8
6	Capitalised faults and non op capex		17.5	17.2	16.9	16.6	16.2
7	Additional allowance		5.0	5.0	5.0	5.0	5.0
8	Quality of Service Allowance		5.0	5.0	5.0	5.0	5.0
9	**Total capex**		**123.3**	**123.0**	**122.7**	**122.4**	**122.0**
	RAV						
10	Opening asset value		1,335.5	1,360.0	1,376.2	1,386.0	1,389.3
11	Total capex		123.3	123.0	122.7	122.4	122.0
12	Depreciation		(98.8)	(106.8)	(113.0)	(119.1)	(125.2)
13	Closing asset value		1,360.0	1,376.2	1,386.0	1,389.3	1,386.1
	ALLOWED ITEMS						
14	Operating costs		98.5	102.8	104.4	103.4	102.5
15	Depreciation		98.8	106.8	113.0	119.1	125.2
16	Return		72.2	73.3	74.0	74.4	74.4
17	Tax allowance		39.6	37.6	36.9	37.9	38.7
18	Capex incentive scheme		9.4	9.0	6.5	3.1	0.7
19	Sliding scale additional income		2.7	2.7	2.8	2.8	2.8
20	Quality incentive		-	-	-	-	-
21	DPCR3 costs		1.7	-	-	-	-
22	**Total allowed costs**		**322.9**	**332.3**	**337.6**	**340.7**	**344.3**
23	Present value of allowed costs		314.6	307.2	296.3	283.8	272.2
24	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,474.1**
	REVENUE						
25	Revenue index		1.000	1.002	1.003	1.005	1.006
26	Discounted revenue index		0.974	0.926	0.880	0.837	0.796
27	**Price control revenue**	**308.2**	**326.9**	**327.4**	**327.9**	**328.5**	**329.0**
28	Excluded services revenue		7.1	7.1	7.1	7.1	7.1
29	Total revenue		334.0	334.5	335.0	335.6	336.1
30	Present value of total revenue		325.4	309.3	294.0	279.5	265.7
31	**TOTAL PRESENT VALUE OVER 5 YEARS**						**1,474.1**
32	PO		6%				
33	X		(1%)				
	Analysis of PO (%):						
34	Include EHV	3%					
35	Exclude metering	(1%)					
36	Change in Opex	(0%)					
37	Depreciation	(2%)					
38	Return	(1%)					
39	Rates	1%					
40	Tax	6%					
41	Other	1%					
42	**Total**	**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.

Appendix 1 Further details on cost assessment

Introduction

This Appendix provides further details on the cost assessment work including:

- normalisation;
- tree cutting costs;
- RAV roll forward; and
- pensions.

Table A1: Detailed 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 (note 2)	Insurance Costs	Average Forecast Non-op Spend (note 3)	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 (note 4)	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
CN - Midlands	54.3	0.0	(13.2)	1.6	42.7	(0.7)	0.0	0.0	(5.1)	0.0	(1.8)	2.3	0.0	0.0	0.1	0.0	0.0	(0.3)	37.2	27.1	3.9	68.2
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)	0.6	0.0	0.0	2.2	0.9	0.0	(0.3)	28.8	34.2	0.0	63.0
United Utilities	31.0	0.0	(15.0)	19.9	35.9	(2.0)	0.0	7.2	(4.7)	0.0	(0.6)	2.5	0.0	0.0	1.5	0.8	(0.4)	(0.3)	39.9	33.0	(3.6)	69.3
CE - NEDL	36.3	0.0	(4.2)	(0.9)	31.2	(0.4)	(0.8)	3.1	(2.8)	(0.2)	(1.0)	1.5	0.0	0.0	2.1	2.3	(0.4)	(0.2)	34.4	14.0	(7.6)	40.9
CE - YEDL	47.5	0.0	(6.4)	(0.5)	40.6	(0.0)	(1.4)	0.0	(6.0)	0.0	(0.9)	1.5	0.0	0.0	2.3	3.5	(0.4)	(0.4)	38.8	22.1	(9.2)	51.7
WPD - South West	29.8	0.0	(8.2)	9.1	30.7	(1.3)	0.0	7.4	(5.4)	0.0	(1.0)	1.0	0.0	0.0	0.1	0.2	0.0	(0.1)	31.6	22.0	(0.2)	53.4
WPD - South Wales	34.7	0.0	(3.6)	(3.5)	27.6	(0.4)	0.0	5.5	(4.0)	0.0	(1.4)	1.4	0.0	0.0	0.3	0.2	0.0	(0.1)	29.2	8.9	(0.1)	38.0
EDF - LPN	56.5	0.0	(15.8)	(3.8)	36.9	(5.1)	0.0	7.0	(3.6)	(1.3)	(1.5)	2.0	(4.4)	0.0	0.0	0.0	0.0	(0.0)	30.0	26.9	5.6	62.5
EDF - SPN	61.2	0.0	(9.6)	1.3	52.9	0.0	(1.7)	6.7	(8.1)	0.0	(4.5)	2.6	0.0	0.0	0.0	0.0	(0.4)	(0.0)	47.4	21.9	0.0	69.3
EDF - EPN	78.9	0.0	(22.0)	(5.6)	51.3	(1.5)	(2.6)	9.8	(8.9)	0.0	(2.2)	2.6	0.0	0.0	0.0	0.0	0.0	(0.0)	48.5	34.1	6.1	88.6
SP Distribution	38.4	1.5	(7.2)	(4.3)	28.4	(2.1)	0.0	0.0	(3.3)	0.0	(1.7)	1.9	0.0	3.2	0.0	0.0	0.0	(0.1)	26.2	29.6	7.9	63.8
SP Manweb	40.4	0.0	(8.6)	(2.2)	29.6	(2.3)	0.0	0.0	(5.2)	0.0	(1.6)	1.7	0.0	0.0	0.0	0.0	0.0	(0.1)	22.1	30.6	1.0	53.7
SSE - Hydro	36.4	0.0	(3.9)	(0.4)	32.1	(1.0)	(1.3)	0.3	(2.7)	0.0	(1.7)	1.4	(1.4)	1.6	1.0	0.0	0.0	(0.1)	28.2	6.8	0.0	35.0
SSE - Southern	60.2	0.0	(15.2)	(0.4)	44.6	(1.5)	(1.5)	0.7	(6.3)	0.0	(3.1)	2.2	0.0	0.0	1.0	0.0	0.0	(0.1)	36.0	21.1	2.8	59.9
Total	**677.2**	**3.0**	**(167.8)**	**4.7**	**517.1**	**(18.3)**	**(10.8)**	**49.2**	**(72.9)**	**(1.5)**	**(23.4)**	**25.1**	**(5.8)**	**4.8**	**10.6**	**7.9**	**(1.6)**	**(2.1)**	**478.3**	**332.3**	**6.6**	**817.2**

Note

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 Intercompany margins have been excluded from DPCR4 Normalised Controllable Costs in full.

3 Average forecast non-operational capex spend incurred in the DNO has been added back. Any depreciation charge incurred by a related party service provider or external service provider has been left in DPCR4 Controllable Operating Costs.

4 Opex and capex faults have been subject to the same normalisation adjustments as DPRC4 Controllable Operating Costs. The normalised faults number has been added back to DPCR4 Controllable Costs for the purposes of benchmarking.

Table A2: Overhead Allocation Adjustment (£ m, 2002/03 prices)

Mar-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
	£'m	£'m	£'m	£'m	£'m	£'m	£'m	£'m	£'m	£'m	£'m	£'m	£'m	£'m
% Indirect Costs (exc margin) Expensed (Opex + total faults)	52%	61%	73%	84%	83%	67%	67%	50%	62%	51%	47%	55%	63%	53%
% Indirect Costs (exc margin) Capitalised (Non fault)	48%	39%	27%	16%	17%	33%	33%	50%	38%	49%	53%	45%	37%	47%
% Difference from Upper/Lower level of Band														
Indirect Costs Expensed (Opex + total faults)	5%	0%	-6%	-17%	-16%	0%	0%	7%	0%	6%	10%	2%	0%	4%
Indirect Costs Capitalised (Non fault)	-5%	0%	6%	17%	16%	0%	0%	-7%	0%	-6%	-10%	-2%	0%	-4%
Adjustment Arising (£'m) (Included on Normalisation spreadsheet)	**3.9**	**-**	**(3.6)**	**(7.6)**	**(9.2)**	**(0.2)**	**(0.1)**	**5.6**	**-**	**6.1**	**7.9**	**1.0**	**-**	**2.8**

Note:
Positive adjustment is an increase to DPCR4 Normalised Controllable Costs, negative adjustment is a decrease to DPCR4 Normalised Controllable Costs.

Average indirect costs allocated to Capital (non-fault) : 38%

Table A3: Calculation of DPCR4 Adjusted Normalised Controllable Costs + Total Faults (£ m, 2002/03 prices)

		Non-allowable elements of Normalised Controllable Costs+Faults						
DNO	DPCR4 Normalised Controllable Costs + Faults	Reverse Regional Adjustments Opex	Reverse Regional Adjustments Faults	Reverse 132kV adj - Scotland Opex	Reverse 132kV adj - Scotland Faults	Remove Ofgem Pension Cost Opex	Remove Ofgem Pension Cost Faults	DPCR4 Adjusted Normalised Controllable Costs + Faults
	£m	£m	£m	£m	£m	£m	£m	£m
CN - Midlands	68.2	-	-	-	-	(2.3)	(2.0)	63.9
CN - East Midlands	63.0	-	-	-	-	(0.6)	(1.7)	60.7
United Utilities	69.3	-	-	-	-	(2.5)	(1.8)	65.1
CE - NEDL	40.9	-	-	-	-	(1.5)	(1.2)	38.2
CE - YEDL	51.7	-	-	-	-	(1.5)	(1.7)	48.5
WPD - South West	53.4	-	-	-	-	(1.0)	(1.4)	51.1
WPD - South Wales	38.0	-	-	-	-	(1.4)	(0.7)	35.9
EDF - LPN	62.5	4.4	1.7	-	-	(2.0)	(1.0)	65.5
EDF - SPN	69.3	-	-	-	-	(2.6)	(0.6)	66.1
EDF - EPN	88.6	-	-	-	-	(2.6)	(1.6)	84.4
SP Distribution	63.8	-	-	(3.2)	(0.5)	(1.9)	(0.6)	57.5
SP Manweb	53.7	-	-	-	-	(1.7)	(0.7)	51.4
SSE - Hydro	35.0	1.4	0.2	(1.6)	-	(1.4)	(0.3)	33.3
SSE - Southern	59.9	-	-	-	-	(2.2)	(1.2)	56.5
Total	**817.2**	**5.8**	**1.87**	**(4.8)**	**(0.5)**	**(25.1)**	**(16.4)**	**778.1**

Table A4: Calculation of DPCR4 Base Operating Costs + Total Faults Allowance (£ m, 2002/03 prices)

		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**	**Adjusted 2002/03 Efficient Costs (Upper Quartile)**	**Average DPCR4 Opex + Total Faults Allowance (2% 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 (= C + I)	K
	£m		£m		£m		£m	£m	£m	£m	£m
CN - Midlands	63.9	84%	53.6	87%	55.9	85%	54.5	54.7	1.1	54.7	51.5
CN - East Midlands	60.7	98%	59.2	99%	60.4	102%	61.7	60.4	1.2	60.4	56.9
United Utilities	65.1	81%	52.4	85%	55.0	81%	52.9	53.4	1.0	53.4	50.3
CE - NEDL	38.2	102%	39.0	100%	38.4	97%	36.9	38.1	-	39.0	36.8
CE - YEDL	48.5	100%	48.6	106%	51.4	97%	46.9	49.0	0.3	49.0	46.1
WPD - South West	51.1	81%	41.6	90%	45.8	76%	39.0	42.1	0.5	42.1	39.7
WPD - South Wales	35.9	93%	33.5	97%	35.0	76%	27.4	32.0	-	33.5	31.6
EDF - LPN	65.5	70%	46.0	72%	46.9	85%	55.7	49.5	3.6	49.5	46.6
EDF - SPN	66.1	72%	47.6	77%	51.1	70%	46.2	48.3	0.7	48.3	45.5
EDF - EPN	84.4	87%	73.7	91%	77.0	85%	71.7	74.2	0.4	74.2	69.8
SP Distribution	57.5	87%	50.1	97%	56.0	82%	47.2	51.1	1.0	51.1	48.1
SP Manweb	51.4	81%	41.4	79%	40.7	82%	42.1	41.4	0.1	41.4	39.0
SSE - Hydro	33.3	100%	33.1	100%	33.1	108%	35.9	34.0	0.9	34.0	32.1
SSE - Southern	56.5	111%	62.9	102%	57.6	108%	60.9	60.5	-	62.9	59.2
Total	**778.1**		682.7		704.3		679.2	688.8	10.9	693.7	653.1

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.

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

Table A5: DPCR4 Operating Costs + Total Faults Allowance - Average (£ m, 2002/03 prices)

DNO	Average DPCR4 Opex + Total Faults Allowance (2% Frontier Shift)	Opex Allowance Buildup: Storm Insurance and Atypicals	Opex Allowance Buildup: Activity Level Adjustment - Tree Cutting	Opex Allowance Buildup: QoS Average Opex Allowance	DPCR4 5 Year Average Opex Allowance	Ofgem Licence Fee Average	Network Rates Average	Pension Allowance	Capitalisation faults and non operational capex (note 1)	DPCR4 5 Year Average Total Opex Allowance
	£m	£m	£m	£m	£m		£m	£m	£m	£m
CN - Midlands	51.5	1.5	1.0	1.2	55.1	1.1	21.0	6.2	-14.6	68.8
CN - East Midlands	56.9	1.3	0.1	1.3	59.6	1.1	25.9	9.3	-15.8	80.2
United Utilities	50.3	0.9	0.0	1.2	52.4	1.1	17.5	7.4	-13.9	64.5
CE - NEDL	36.8	1.9	0.5	0.8	39.9	0.7	13.4	5.2	-10.6	48.6
CE - YEDL	46.1	0.5	0.0	1.2	47.8	1.0	19.1	6.2	-12.7	61.4
WPD - South West	39.7	1.2	2.1	2.6	45.5	0.7	17.2	8.6	-12.0	59.9
WPD - South Wales	31.6	2.3	2.5	1.0	37.4	0.5	13.1	5.5	-9.9	46.6
EDF - LPN	46.6	0.0	0.0	0.5	47.2	1.0	21.9	15.3	-12.5	72.9
EDF - SPN	45.5	0.7	0.0	0.9	47.0	1.0	11.6	7.4	-12.5	54.6
EDF - EPN	69.8	1.9	2.6	1.6	76.0	1.6	25.6	9.7	-20.2	92.7
SP Distribution	48.1	1.6	1.0	1.0	51.8	0.9	32.4	4.7	-13.7	76.1
SP Manweb	39.0	1.2	1.7	0.9	42.8	0.7	12.8	11.9	-11.3	56.9
SSE - Hydro	32.1	1.6	1.3	0.8	35.8	0.3	12.7	3.4	-9.4	42.8
SSE - Southern	59.2	1.6	1.1	1.6	63.6	1.3	35.9	18.4	-16.9	102.3
Total	653.1	18.2	13.9	16.7	701.9	13.0	280.0	119.2	-185.9	928.2

Note

1 The capitalised faults and non operational capex has been calculated as 26% of DPCR4 5 year average allowance plus Ofgem Licence fee.

Table A6: Movement of March paper DNO base case opex forecasts to 'Adjusted DPCR4 Average Forecast (£ m, 2002/03 prices)

DNO	CN - Midlands	CN - East Midlands	United Utilities	CE - NEDL	CE - YEDL	WPD - South West	WPD - South Wales	EDF-LPN	EDF-SPN	EDF-EPN	SP Distribution	SP Manweb	SSE - Hydro	SSE - Southern	Total
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
Total Opex and Cost of Sales per March 2004 Paper	856	817	750	480	609	648	478	836	807	998	807	540	453	969	
Difference between March 2004 Paper and FBPQ	6	-	36	8	12	(2)	(1)	16	0	19	-	(1)	10	18	
Total Opex and Cost of Sales per FBPQ	**862**	**817**	**786**	**487**	**621**	**646**	**477**	**852**	**807**	**1,017**	**807**	**540**	**463**	**987**	
Less Non-Controllable Costs per FBPQ															
- exit charges	(89)	(71)	(81)	(72)	(69)	(25)	(20)	(110)	(89)	(123)	(255)	(72)	(53)	(103)	
- NTR costs	(66)	(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	**(519)**	**(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	**350**	**300**	**364**	**212**	**263**	**277**	**180**	**357**	**338**	**498**	**277**	**210**	**192**	**330**	
Adjusted DPCR4 Average Forecast	**70**	**60**	**73**	**42**	**53**	**55**	**36**	**71**	**68**	**100**	**55**	**42**	**38**	**66**	**830**

Table A7: Increase in Tree Cutting Allowance (£ m, 2002/03 prices)

DNO Name	CSV	Upper Quartile Cost per CSV £k	Annual Cost implied using Upper Quartile Cost x CSV (i.e. costs allowed in regressed costs) Note 1 £m	Average Annual Model Costs Note 2 £m	Increased Allowance (Higher of regressed or modelled costs) £m	Increase in allowance for change in activity level £m
CN - Midlands	21.9	167	3.7	4.6	4.6	1.0
CN - East Midlands	24.1	167	4.0	4.1	4.1	0.1
United Utilities	21.2	167	3.6	2.6	3.6	-
CE - NEDL	14.2	167	2.4	2.8	2.8	0.5
CE - YEDL	19.2	167	3.2	2.5	3.2	-
WPD - South West	15.1	167	2.5	4.6	4.6	2.1
WPD - South Wales	11.1	167	1.9	4.4	4.4	2.5
EDF - LPN	15.2	167	-	-	-	-
EDF - SPN	18.3	167	3.1	2.7	3.1	-
EDF - EPN	32.0	167	5.3	8.0	8.0	2.6
SP Distribution	21.0	167	3.5	4.5	4.5	1.0
SP Manweb	15.0	167	2.5	4.2	4.2	1.7
SSE - Hydro	10.8	167	1.8	3.1	3.1	1.3
SSE - Southern	26.6	167	4.5	5.6	5.6	1.1

Table A8: Detailed RAV roll forward (£ m, 2002/03 prices)

DNO	Including Meters																						Excluding Meters	Meters
	Balance at 1 April 1998	1998/99 Net Additions	1998/99 Dep'n	Balance at 31 March 1999	1999/00 Net Additions	1999/00 Dep'n	Balance at 31 March 2000	2000/01 Net Additions	2000/01 Dep'n	Balance at 31 March 2001	2001/02 Net Additions	2001/02 Dep'n	Balance at 31 March 2002	2002/03 Net Additions	2002/03 Dep'n	Balance at 31 March 2003	2003/04 Net Additions	2003/04 Dep'n	Balance at 31 March 2004	2004/05 Net Additions	2004/05 Dep'n	Balance at 31 March 2005	Balance at 31 March 2005	Balance at 31 March 2005
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
CN – Midlands	929.9	74.8	(70.0)	934.7	69.7	(72.2)	932.2	70.5	(74.3)	928.4	89.8	(76.5)	941.7	90.7	(79.2)	953.2	82.3	(81.9)	953.6	82.1	(84.4)	951.3	930.4	20.9
CN – East Midlands	996.1	83.3	(76.8)	1002.5	82.3	(79.4)	1005.5	94.4	(81.9)	1018.0	59.6	(84.7)	992.9	71.1	(86.5)	977.5	82.0	(88.7)	970.8	78.2	(91.2)	957.9	939.3	18.6
United Utilities	773.5	100.0	(86.1)	787.3	89.0	(89.2)	787.2	83.9	(91.9)	779.2	75.1	(74.3)	780.0	88.7	(51.5)	817.2	94.2	(56.0)	855.5	85.9	(60.7)	880.7	859.8	20.9
CE – NEDL	541.0	40.2	(42.3)	538.9	46.6	(43.5)	541.9	48.4	(45.0)	545.4	59.7	(46.4)	558.7	55.7	(48.3)	566.1	48.8	(50.0)	564.9	51.0	(42.4)	573.6	558.2	15.4
CE – YEDL	857.7	87.2	(68.4)	876.5	71.9	(71.1)	877.3	50.5	(73.3)	854.5	41.7	(74.8)	821.4	65.4	(76.1)	810.8	77.7	(78.1)	810.4	89.6	(80.4)	819.5	804.0	15.5
WPD – South West	667.8	64.7	(48.0)	684.6	62.2	(49.9)	696.9	64.6	(51.8)	709.6	65.4	(53.8)	721.3	61.5	(55.8)	727.0	60.8	(57.6)	730.2	62.2	(59.5)	733.0	717.6	15.4
WPD – South Wales	520.3	72.4	(43.0)	549.6	57.0	(45.2)	561.4	53.1	(46.9)	567.6	51.0	(40.0)	578.6	48.2	(39.1)	587.7	43.1	(41.5)	589.4	40.7	(43.6)	586.5	573.9	12.6
EDF – LPN	892.7	87.9	(66.0)	914.6	99.4	(68.6)	945.3	76.4	(71.6)	950.1	57.4	(74.0)	933.6	79.3	(75.7)	937.2	80.4	(78.1)	939.5	82.1	(80.5)	941.1	922.2	18.9
EDF – SPN	525.3	49.3	(47.5)	527.1	46.0	(49.0)	524.1	56.3	(50.4)	530.0	76.5	(52.1)	554.5	71.8	(54.4)	571.9	78.5	(45.8)	604.6	103.1	(42.1)	665.6	651.0	14.6
EDF – EPN	1068.2	183.7	(98.6)	1153.3	88.8	(104.2)	1137.9	107.9	(106.9)	1138.9	106.4	(110.2)	1135.0	102.8	(113.4)	1124.4	127.3	(116.5)	1135.2	140.0	(96.6)	1178.6	1151.3	27.3
SP Distribution	1474.8	67.9	(96.0)	1446.7	62.9	(97.8)	1411.7	67.3	(99.4)	1379.6	88.2	(101.2)	1366.7	98.6	(103.5)	1361.7	102.1	(106.1)	1357.7	61.6	(108.8)	1310.5	1288.8	21.7
SP Manweb	647.2	72.3	(47.8)	671.7	58.2	(50.0)	679.9	50.5	(51.8)	678.6	63.6	(53.3)	688.9	82.4	(55.2)	716.1	69.8	(57.7)	728.1	93.6	(59.8)	761.9	747.4	14.5
SSE – Hydro	746.4	66.6	(42.3)	770.7	47.0	(44.1)	773.6	51.9	(45.3)	780.2	45.8	(46.7)	779.3	34.7	(47.9)	766.1	33.2	(48.8)	750.5	34.9	(49.7)	735.8	727.1	8.7
SSE – Southern	1408.4	129.6	(97.8)	1440.2	108.7	(101.7)	1447.3	90.3	(105.0)	1432.5	96.2	(107.7)	1421.0	82.3	(110.6)	1392.7	85.8	(113.1)	1365.3	100.2	(115.7)	1349.8	1335.5	14.3
TOTAL	12,049.4	1,179.7	(930.7)	12,298.4	989.7	(965.9)	12,322.2	966.1	(995.5)	12,292.8	976.5	(995.6)	12,273.6	1,033.2	(997.2)	12,309.6	1,066.0	(1,020.0)	12,355.7	1,105.3	(1,015.5)	12,445.5	12,206.2	239.3

Table A9: Movement of DNO DPCR4 forecast Base case capex (Ofgem March 2004 paper) to adjusted DPCR4 forecast (£ m, 2002/03 prices)

DNO	**DNO March paper forecast** (Base case)	Adjustments	**DPCR4 FBPQ forecast** (Base Case)	ESQCR	Metering	Faults capitalised	Pension funding deficit cost	Fluid filled cables	Capitalised overhead adjustment	Inter-company Margin	Lane Rentals	**Adjusted DPCR4 FCST** (Base case)
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
Aquila	638	-	638	(19)	(41)	(66)	(10)	-	(13)	-	(3)	487
EME	692	(9)	683	(66)	(65)	(42)	(17)	-	-	-	(36)	457
UU	592	6	598	(11)	(19)	(106)	(16)	-	12	(4)	-	455
NEDL	303	-	303	-	(22)	(48)	-	-	21	-	-	254
YEDL	442	-	442	-	(35)	(94)	-	-	23	-	-	335
WPD - SWest	378	4	382	(29)	(18)	(79)	-	-	1	-	-	256
WPD - SWales	217	3	220	(1)	(11)	(37)	-	-	0	-	-	171
EDF - London	791	(11)	780	(1)	(56)	(62)	-	(113)	(20)	8	-	537
EDF - Seeboard	638	1	639	(6)	(60)	(59)	-	(29)	-	-	-	485
EDF - Eastern	1,043	15	1,058	(4)	(60)	(96)	-	(14)	(21)	(10)	-	852
SP Distribution	605	(4)	601	-	(47)	(102)	-	-	(26)	(30)	-	396
SP Manweb	598	(4)	594	-	(28)	(66)	-	-	(4)	(33)	-	464
SSE - Hydro	239	-	239	(6)	(11)	(16)	-	-	-	-	-	206
SSE - Southern	594	-	594	(9)	(26)	(40)	(11)	-	(10)	-	-	498

Table A10: DPCR4 Pension allowances calculation (£ m, 2002/03 prices)

DNO	Pension Deficit	Distribution Deficit	Disallowed ERDCs	Allowed Deficit	Deficit Funding per annum
Notes	**(1)**	**(2)**			**(3)**
	£m	£m	£m	£m	£m
CN - Midlands	90	72.0	66.5	5.5	0.4
CN - East Midlands	125	100.0	36.8	63.2	4.9
United Utilities	77	58.5	45.9	12.6	1.0
CE - NEDL	91	73.0	56.4	16.6	1.3
CE - YEDL	19	18.7	-	18.7	1.4
WPD - South West	120	96.0	55.4	40.6	3.1
WPD - South Wales	80	64.0	28.0	36.0	2.8
EDF - LPN	208	145.6	19.6	126.0	9.7
EDF - SPN	120	91.2	46.4	44.8	3.4
EDF - EPN	32	32.0	-	32.0	2.5
SP Distribution	-	-	-	-	-
SP Manweb	140	112.0	6.6	105.4	8.1
SSE - Hydro	-	-	-	-	-
SSE - Southern	250	200.0	27.2	172.8	13.3
Total	**1,352**	**1,063.0**	**388.8**	**674.2**	**51.9**

Notes:

(1) Total deficit as advised by companies

(2) 80% of total, except LPN (70%), UU (76%), EPN and YEDL (both 100%)

(3) Allowed deficit spread over 13 years