Electricity Distribution Price Control Review

Policy document

March 2004

Summary

Every price control review faces a combination of new challenges and familiar issues. For the current distribution price review, the major new challenges include how to develop an incentive mechanism for investment to accommodate distributed generation. In addition, new ways of addressing some of the traditional issues have been developed in recent years – particularly to ensure that cost efficiency does not inhibit necessary investment or performance improvements. This review will build on these initiatives.

This paper builds on extensive consultation over the past two years, and particularly on publications in July, October and December 2003. It sets out the broad policy framework within which Ofgem intends to develop price control proposals and summarises the forecast business plans submitted by the distribution companies. The paper lays the groundwork for the publication of Ofgem's Initial Proposals on the review in June 2004.

Overall approach to investment

Ofgem's priority for this review remains the protection of consumer interests. One aspect of this is ensuring that prices are not higher than they need to be. Another is ensuring that companies are able to finance the maintenance and investment required to sustain networks and to improve performance. This would not be consistent with forcing companies to cut costs to levels that will lead to failing networks. Indeed, such results have not flowed from Ofgem's actions to date - the record shows that network performance has improved substantially since privatisation. This month's report by the Trade and Industry Select Committee states that "performance of ... the distribution networks has been and remains very good, both absolutely and in comparison with networks abroad".[1] The present review will provide incentives for the companies to continue that improvement in performance.

Distribution companies have invested 65 per cent more in real terms in the 13 years since privatisation than in the 13 years before. Some commentators have suggested that Ofgem previously set limits on capital expenditure too tightly. In fact, most companies have spent less than allowed. In aggregate the price control "allowed" for around £5.5 billion of net investment over the period 2000 to 2005 and projected expenditure by the companies is around £5.3 billion – i.e. companies are forecasting to underspend the

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[1] "Resilience of the National Electricity Network", Third Report of Select Committee on Trade and Industry,

allowances made by Ofgem. The underspend to date, for the 3 years ending March 2003, is around £300m. Arguably therefore if higher investment is needed in the future (as the companies are indicating), this will not be achieved solely by Ofgem giving companies even higher allowances or revenues. It is a valid question as to whether the rewards that companies receive for reducing their investment costs are too great. Options for reducing these rewards are set out in this paper.

For the period 2005 to 2010, companies are projecting aggregate net capital expenditure of between £8 and £9 billion, depending on the extent of performance improvement (an increase of 48 to 66 per cent over actual and projected expenditure for the current period 2000 to 2005). However, the pattern is more complicated than this total figure would suggest. There is a wide range between companies' estimates. Table 1 sets out the change in operating costs, capital expenditures and price control revenue proposed by each of the companies to maintain current performance levels:

Table 1: Distribution company base case submissions[1]

	Percentage change 2005-10 over 2000-05		
Company	Operating costs[2]	Net capital expenditure	Price control revenue[3]
CE – NEDL	-1%	5%	-14%[4]
CE – YEDL	-9%	14%	-11%[4]
CN – East Mids	0%	71%	3%
CN – Midlands	1%	33%	5%
EDF – EPN	30%	71%	6%
EDF – LPN	20%	95%	16%
EDF – SPN	24%	47%	37%
SP Distribution	-4%	23%	4%
SP Manweb	-3%	41%	11%
SSE – Hydro	3%	21%	7%
SSE – Southern	9%	23%	7%
United Utilities	3%	23%	9%
WPD-SWales	3%	-5%	8%
WPD-SWest	22%	17%	10%

1 Figures are as submitted by the companies (no Ofgem adjustments) therefore direct comparison will be misleading as there are some differences in the basis upon which companies have produced their forecasts.
2 Includes NGC exit charges, cost of sales and depreciation.
3 Figures as calculated by the companies and not verified by Ofgem. The change in price control revenue will depend on various factors, particularly on the change in assumed allowed costs, the cost of capital and depreciation, rather than the change in actual to projected operating and capital expenditure as shown in the first two columns of this table.
4 Costs of pension deficits and other uncertain costs were not included by the company.

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10 March 2004, paragraph 49

Care should be exercised in making comparisons between companies at this stage. The data reproduced in table 1 has been provided by the companies and has not been adjusted by Ofgem for consistency. Differences between the companies may therefore result partly from differences of approach. For instance, the companies have taken different approaches to areas of costs that are particularly uncertain (such as pension costs), with some companies including estimates but others excluding them at this stage.

Most distribution companies are projecting increases in capital expenditure of up to 25 per cent. Some suggest larger increases. The different increases (or reductions) in operating costs between companies are predominantly due to differences in pension costs and/or depreciation. Overall, only two companies are projecting reductions in distribution charges (both before pension costs). Most show increases of up to 10 per cent (two of the EDF Energy Networks companies project significantly higher increases in charges).

Substantial work to review and cross-check the companies' projections is well advanced but not yet completed. It is already evident that, across the industry as a whole, an increase in capital expenditure above current levels is expected. However, some of the companies proposing more substantial increases have not yet provided adequate justification. Ofgem's work will focus on confirming, or developing alternatives to, the companies' cost projections before Initial Proposals are published in June.

One of the factors which will influence companies' views on investment is the allowed cost of capital. This paper sets out Ofgem's initial views on the range which may be appropriate for the cost of capital at this review. Ofgem intends to use a post-tax approach to the cost of capital, which complicates comparisons with previous reviews – but on the same basis as the 6.5 per cent allowed at the last review, the range proposed here is equivalent to between 6.0 and 7.2 per cent. Ofgem considers that longer-term factors (including the need to finance investment) justify the range proposed, even though some of the market-based parameters used to estimate the cost of capital have declined substantially since the last review and thus could suggest lower figures.

Investment to support distributed generation is not included in Table 1. In this paper, Ofgem confirms arrangements to incentivise distribution companies to take a more proactive and positive approach to generators wanting to connect. This is delivered mainly by a scheme that offers distribution companies real opportunities for higher returns if they connect generation in a cost-effective manner, combined with strong protection against any downside risks they face. The costs of associated investment will generally fall on the generators that benefit, rather than demand consumers. Recognising the importance of innovation, consumers' money will be available to distributors that invest in new solutions, on condition that the companies can justify their expenditure in a transparent and open way. This is expected to reduce prices in the longer term.

Overall approach to incentives and performance

The issues of investment and performance need to be seen in the context of a package of incentives that are established by the price control review. Ofgem's general "RPI-X" framework has been supplemented by developments over the past few years (including the Information and Incentives Project or IIP). Ofgem must of course, also, learn from experience, notably the October 2002 storms.

This review will deliver clearer, more predictable incentives and avoid, where possible, incentives where the reward depends on an ex post evaluation of whether the action was "efficient" or where Ofgem is required to agree management decisions.

Incentives for efficiency must be balanced with incentives to deliver quality of service and other outputs. Where aspects of "quality" (such as long term network health) cannot be quantified, this becomes difficult and, given the reduced capacity for further cost reductions, may justify reducing incentives to save costs (not least recognising the risk that costs could be saved by cutting corners).

The risk that incentives distort decisions also needs to be addressed, for example by avoiding major discontinuities in the incentive regime. Therefore, proposals to reduce the financial impact of discretionary decisions on categorisation of costs between operating and capital expenditure are put forward for consultation. Similarly, reductions in incentives on companies to avoid paying compensation following power outages are proposed, by exposing the company to similar penalties irrespective of whether compensation is claimed or not.

Maintaining a relatively simple package of incentives will inevitably leave various aspects of "desirable" behaviour unincentivised. Therefore, Ofgem will continue to monitor and, if appropriate, publicise companies' performance on other aspects of service. Suggestions are made to introduce a discrete reward, set a relatively modestly level, to support good performance in such areas.

Ofgem is also committed to reducing the scope of regulation where this is possible and consistent with its statutory objectives – this document sets out proposals for the removal of the Overall Standards of Performance.

Summary of key issues

Other than the work on cost assessment described above, Table 2 summarises the areas where Ofgem has decided the approach it will take in developing Initial Proposals and the outstanding policy areas that require further consultation.

A public workshop will be held in London on 20 April 2004 to discuss the issues raised (a registration form can be found in Appendix 6).

Formal responses to this paper are invited by 5 May 2004.

Initial Proposals on the review will be published for consultation in late June 2004.

Table 2

Scope and form of price control and incentives

Issue	Proposal	Further consideration
Duration	5 years	
Inflation measure		RPI or CPI
NGC Exit charges	Pass-through	
Rates		Treatment to be determined
EHV charges	Include in price control	
Revenue driver	Retain 50:50 split Use actual consumer numbers	Weighting on EHV
Losses	Simplify mechanism, remove all adjustments except modified generation adjustment 5 year rolling incentive	Calculation of targets
Uncertainty	Defined new costs to be recognised when they arise	Mechanism to be used
Cost categorisation		Treat fault costs in the same way as capex Treatment of other opex
Strength of incentives	5 year rolling retention mechanism	Reduce incentives to cut capex
Metering	Separate from distribution price control	Details of metering control

Quality of supply

Issue	Proposal	Further consideration
Main incentive	Number and duration of interruptions	Target levels, rates and exposure cap. Approach to audits
Severe weather	Exclude from main incentive Separate severe weather compensation (resilience incentive) Monitor resilience measures	Any need for pass-through, exposure cap or regional variation
Overall standards	Remove Continue to monitor some aspects	
Priority service consumers	Focus on accurate register, improved communication and sharing of best practice	
Business consumers	Same targets for all low voltage consumers	HV consumers depend on willingness to pay
Worst-served consumers	Monitor and publish performance	
Telephony	Retain survey Include speed of response in survey	Form of the incentive scheme
Environmental	Monitor and publish performance	Undergrounding for visual amenity based on willingness to pay and forecast costs
Miscellaneous		Annual reward

Distributed generation

Issue	Proposal	Further consideration
Pass-through of costs	80 per cent	
Incentive rate	£1.5/kW plus £1/kW for O&M	Higher rate for SSE-Hydro
Cap	Limit on return at 2 x cost of capital	
Collar	Floor on return at cost of debt	
Eligibility	As costs incurred for pass-through As DG connects for £/kW	
High cost projects	Separate treatment over £200/kW	
Innovation	Endorsed concepts of Registered Power Zones and Innovation Funding Incentive	Details to be finalised

Financial issues

Issue	Proposal	Further consideration
Cost of capital	Post-tax	Rate used – range of 5.0 per cent to 5.9 per cent post-tax[2]
Pensions	Allowance for pension deficit attributable to distribution, excluding unfunded severance No adjustment for under/over funding to 2005	Detailed calculations
Financial indicators		Specific indicators and values
Financial ringfence	As now, except for conditional cash lock up	

[2] Post tax equity, pre-tax debt. This is equivalent to 6.0 per cent to 7.2 per cent on a pre-tax basis, or 4.2 per cent to 5.0 per cent on the post-tax definition used by Ofwat.

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1. Introduction

1.1. The existing price controls on the Distribution Network Operators (DNOs) are due to be reset with effect from 1 April 2005. The work to review these price controls is now well underway and the scope and nature of the work was explained in the first consultation paper, published in July 2003. This document also set out the objectives for the price control 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 (present and future), wherever appropriate by promoting effective competition. The Electricity Act also sets out other important duties for Ofgem[3], 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 has also other environmental duties as set out in various other Acts[4]. Ofgem will have regard to all of its duties when carrying out its functions.

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

Project update

1.4. Since the publication of the December 2003 second consultation document there have been a number of developments in the project including:

- DNOs have submitted their forecast business plans;
- Ofgem and its consultants have undertaken a series of visits to the DNOs to discuss their historic and forecast business plans;
- Ofgem has held bilateral meetings with the senior management of each DNO;
- a workshop was held on 29 January to discuss issues associated with Registered Power Zones (RPZs) and the Innovation Funding Incentive (IFI). This was attended by a wide range of interested parties including DNOs, academics/researchers and equipment manufacturers; and
- the second phase of the consumer survey has commenced.

1.5. The Ofgem-DNO working groups have also met on a number of occasions to discuss key areas of the price control review and an additional working group, focusing on metering issues, was established in January 2004.

Purpose and structure of this document

1.6. This policy document sets out Ofgem's further thoughts on a number of key policy issues for the price control review, in the light of responses to the December second consultation. The intention is to set out, where possible, final positions for many of the policy issues covered by the review. This should help ensure that there is a better shared understanding of the price control and incentive framework – which should help ensure that the work on assessing DNOs' costs is carried out within a more certain framework. 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 and in the Summary.

1.7. The 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 sets out Ofgem's proposals on the scope and structure of the price control and the incentive framework;

- **quality of service and other outputs (Chapter 4)** – this Chapter sets out Ofgem's proposals on the framework for the regulation of outputs that companies may be required to deliver over the next price control period. This includes revisions to the role, scope and form of the Guaranteed and Overall Standards of Performance, incentives under the Information and Incentives Project and incentives on network resilience;

- **distributed generation (Chapter 5)** – this Chapter sets out Ofgem's proposals on the incentive framework for DNOs in relation to distributed generation. This includes a final view of the value of the incentive rate and the proportion of costs that will be treated as a pass-through. It also sets out Ofgem's further thoughts on the Innovation Funding Incentive (IFI) and Registered Power Zones (RPZs);

- **assessing costs (Chapter 6)** – this Chapter provides an update on the work that Ofgem is undertaking to assess DNOs' costs including a summary of the projections provided by the DNOs;

- **financial issues (Chapter 7)** – this Chapter sets out Ofgem's further thinking on pensions costs, the financial ringfence and sets out an initial range for the cost of capital;

- **calculating the capital and operating expenditure incentive payments (Appendix 1)** – this Appendix sets out how the incentive payment for the rolling adjustment for both capex and opex will be calculated for efficiency savings made in this price control period;

- **losses (Appendix 2)** – this Appendix sets out more detailed information on the operation of the losses incentive;

- **developing a Regulatory Impact Assessment (RIA) for metering (Appendix 3)** – this Appendix sets out the questions and issues that need to be considered in developing a RIA for metering – where Ofgem would particularly welcome quantified responses;

- **developing a RIA for quality of service (Appendix 4)** – this Appendix sets out the questions and issues that need to be considered in developing a RIA for quality of service – where Ofgem would particularly welcome quantified responses;

- **summary of DNOs' forecasts (Appendix 5)** – this Appendix sets out a summary of the forecast information that DNOs submitted in their business plans. A more detailed summary has also been published (see below); and

- **registration of interest for the April workshop (Appendix 6)**.

1.8. Ofgem has also published on its website (www.ofgem.gov.uk):

- a separate Appendix which sets out more detailed information on the DNOs' forecasts;[5]

- RIAs for:

  - distributed generation and the structure of electricity distribution charges; and

  - Registered Power Zones (RPZs) and the Innovation Funding Incentive (IFI);[6]

- a separate Appendix which contains background information and analysis on the cost of capital. Ofgem has also published a report, produced by Smithers & Co, on estimating one of the key parameters of the cost of capital;[7] and

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[5] "Summary of DNO forecasts appendix", Ofgem, March 2004
[6] "Regulatory Impact Assessment for Registered Power Zones and the Innovation Funding Incentive", Ofgem, March 2004
[7] "Beta Estimates...provided to Ofgem", Smithers & Co. Ltd., 15 March 2004

- a report, produced by its consultants Mott MacDonald & British Power International (MM-BPI), on the costs associated with distributed generation.[8]

Responding to this document

1.9. 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.

1.10. Responses are particularly invited on those issues where the treatment for Initial Proposals is still under consideration – these are set out at the end of each Chapter and in the Summary. Respondents are welcome to comment on other issues but Ofgem does not intend to revisit the issues where proposals are set out in this document – unless it changes its position.

1.11. Responses to this document and any of the separate Appendices and reports that Ofgem has published should be received by 5 May 2004. They should be sent to:

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1.12. Unless marked as confidential all responses will be published by placing them in Ofgem's library or on the website. It would be helpful if responses could be submitted both electronically and in writing. Any questions on this document

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

should, in the first instance, be directed to Paul O'Donovan, who can be contacted on 020 79017414 or by email at Paul.ODonovan@ofgem.gov.uk

2. Timetable 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 October update.

2.2. Of the output milestones set out in the December document for the period January to end March, 5 were clear milestones for Ofgem and these were achieved on time.

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

Table 2.1: Updated timetable for the price control review

Date	Output Milestone
March 2004	**Policy Paper published**
April 2004	Public workshop on March policy document (20th) Visits to DNOs to discuss cost projections (April and May) Publish revised version of financial model Structure of Charges update paper
May 2004	Responses received to March policy document (5th May) Finalise cost projections for initial proposals (internal milestone) Publish results from second phase consumer research
June 2004	**Initial Proposals Paper published (including revenue allowances – P0/Xs) (target 28 June)**
July 2004	Public workshop on initial proposals (1 July) 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 the price controls

Introduction

3.1. This Chapter sets out Ofgem's further thinking on the form, structure and scope of the price controls that should apply to the DNOs including the appropriate incentive framework. Where possible, Ofgem has set out its proposals for policy areas – these are highlighted.

3.2. The broad framework of price regulation (i.e. RPI-X) that applies to DNOs has worked well since privatisation. Costs have fallen and quality of service has improved. A number of important developments have been introduced including the increased focus on output regulation under the quality of service incentive scheme. RPI-X regulation will continue to be used as the main 'regulatory tool' for protecting the interests of consumers and providing appropriate incentives to companies. Where possible, these incentives should be clear and mechanistic – generally avoiding incentives where the reward (or penalty) depends on ex post evaluation of whether a company's action or behaviour was efficient or appropriate.

3.3. It is also important that the incentives towards efficiency are balanced with those to deliver quality of service and other outputs – it would not be appropriate to create a framework which pushed companies towards short-term cost cutting irrespective of the impact on the 'quality' (including the long term condition of the network) that they deliver to consumers – particularly where the relationship between costs and outputs is hard to define.

3.4. Ofgem is also keen to ensure that the incentives provided to companies do not distort decisions. Whilst it is not possible to anticipate with certainty how companies will react to the incentives provided to them it is important that where problems are identified they are rectified.

Form and structure of the price controls

3.5. As explained above, the RPI-X form of price regulation has resulted in companies reducing costs and improving quality of service. Ofgem will retain the broad RPI-X framework but there are a number of areas where changes are proposed.

Revenue drivers

3.6. The existing price control is designed so that the total amount of revenue that a company is allowed to recover varies with relation to volume as well as being indexed to RPI. This provides financial incentives to companies to respond to the demands of their consumers and protects them against increases in costs driven by higher levels of demand.

3.7. Under the existing price controls the revenue driver is 50 per cent weighted to the number of units distributed – where this is weighted between units distributed under three Low Voltage (LV) categories and High Voltage (HV) and the remaining 50 per cent is fixed as it is weighted to a pre-determined projection of the number of consumers.

3.8. The December document consulted on whether any changes should be made to the revenue driver and in particular whether a capacity based driver should be introduced.

Views of respondents

3.9. Almost all respondents suggested that it would not be appropriate to introduce a capacity revenue driver to the price control. It was argued that, at least for the majority of consumers, units distributed provide a suitable proxy for capacity and that defining and measuring incremental capacity provided, particularly at lower voltage levels, would be very difficult and costly.

3.10. Most of the respondents also argued that Ofgem should retain existing weight of the revenue driver, i.e. 50:50 between units distributed and consumer numbers. One DNO argued that it may be necessary to make an adjustment to the revenue driver to compensate for the effect of distributed generation and in particular domestic CHP (i.e. if units distributed fell significantly), but that this was unlikely to be needed until after 2010. One DNO argued that the revenue driver should only be linked to actual consumer numbers.

Ofgem's proposal

3.11. **Ofgem proposes to retain the broad form of the existing revenue driver so that it is weighted equally (50:50) between units distributed and the number of consumers – i.e. no capacity based driver will be introduced.**

3.12. **Ofgem also proposes to:**

- **use the actual number of consumers reported each year by the DNOs as defined in the IIP Regulatory Instructions and Guidance (RIGs)**; and
- **review the weightings applying to the various voltage categories within the units distributed revenue driver.** Revised weightings will be published in the June initial proposals document.

Price index

3.13. At present the revenue that DNOs are allowed to recover through the price control is uprated each year by the Retail Price Index (RPI) minus (or plus) a specified percentage (i.e. 'X') – so called RPI-X. The Treasury has changed the inflation target that should be used by the Monetary Policy Committee of the Bank of England from RPI to the Harmonised Index of Consumer Prices (HICP) – which is known in the UK as the Consumer Prices Index (CPI).[9]

3.14. This change raises the question of whether CPI should replace RPI for price control purposes. If the CPI broadly captures changes in the underlying costs faced by DNOs (i.e. protects them and consumers against changes in inflation), it may be appropriate to adopt CPI from 1 April 2005. **Views are welcomed on this issue.**

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[9] The announcement was made by the Chancellor of the Exchequer in his pre-Budget report in June 2003. The use of CPI as the basis for the operational target for inflation for took effect from December 2003.

The scope of the price controls

3.15. This section sets out Ofgem's proposals on the scope of the revised DNO price controls in the light of responses to the December document.

Transmission exit charges

3.16. Under the existing price controls, transmission exit charges are outside the scope of price control revenue. This enables the DNOs to pass through the full cost of exit charges to consumers.

Views of respondents

3.17. Many of the DNOs argued that transmission exit charges should remain as a full pass through item. Several DNOs commented that they have little influence on the development of new transmission connections, and that much of the costs incurred relate to asset replacement. Several DNOs also noted that the transmission companies are incentivised to manage costs in relation to the development of transmission connections and that providing further incentives to DNOs may have perverse effects.

3.18. Many DNOs commented that the costs of existing transmission connections are largely sunk and that charges are levied to ensure the costs of past investments can be recovered by the transmission company. It was argued that incentivising DNOs to manage transmission exit charges will have little impact and would expose them to risks of not fully recovering costs

3.19. Three respondents expressed support for some limited form of incentive on transmission exit charges. It was commented that the timing of expenditure in relation to new or replacement assets is partly within the control of the DNO. It was suggested that an incentive on new or replacement assets may therefore ensure that expenditure is incurred efficiently and may also encourage DNOs to connect distributed generation where this avoids or defers investment in transmission connection assets.

Ofgem's proposal

3.20. Ofgem recognises that there may be scope for DNOs, at least in the longer term, to influence the level of transmission exit charges – particularly in relation to its decisions about new or replacement assets and that this may increase in future. However, given that the transmission companies are already provided with incentives towards efficiency, and that recent changes to the charging methodology used by NGT should significantly reduce the level of transmission charges, **Ofgem does not propose to change the treatment of transmission exit charges at this review.**

Treatment of wheeled units

3.21. Wheeled units are those which flow from one distribution network directly to another – for which a charge is paid by the company receiving the energy. At present, the revenue received by the DNO distributing the energy to a neighbouring network is excluded from the price control, whereas the costs incurred by the DNO receiving the energy are not.

Views of respondents

3.22. Six DNOs argued that wheeling charges should be treated as a full cost pass-through in line with transmission exit charges. They argued that this would give a better balance of incentives between developing transmission and distribution connection points. One DNO suggested that charges for wheeled units should be capitalised rather than expensed in lieu of the investment avoided in transmission assets.

3.23. One respondent suggested that wheeling costs should be included within the scope of the price control to incentivise DNOs to control the costs of bringing energy on to their networks.

Ofgem's proposal

3.24. The existing arrangements for the treatment of the costs paid by DNOs receiving wheeled units could create distorted incentives relative to transmission charges which are excluded from the price control. **Ofgem proposes to allow the pass-through of the costs associated with wheeling charges.**

3.25. If the revenue recovered by the DNO wheeling the units is not included within the price control, it would have an incentive to increase charges and the DNO receiving the units would have no incentive to minimise the charges it paid as its costs would be passed-through at the expense of consumers. This would not be appropriate so **Ofgem proposes to include the revenue associated with wheeled units within the price control.**

EHV charges

3.26. Revenue collected from charges made to EHV consumers is currently outside of the scope of the price controls. However, DNOs have a licence requirement to set charges to follow a path consistent with the profile underlying regulated revenue. Disputes in relation to EHV charges can also be referred to Ofgem for determination.

Views of respondents

3.27. Three DNOs reiterated their view that EHV should remain outside the scope of the price controls – some DNOs recognised that if an appropriate revenue driver could be developed then EHV charges could be included in the price control. DNOs suggested that EHV charges are site specific and inclusion within the price controls may reduce flexibility in the level and form of the charges made. One DNO argued that the inclusion of EHV charges within the price controls would provide protection against the risk of stranded costs associated with falling numbers of EHV consumers. Energywatch and two other respondents argued that EHV charges should be included within the price control.

3.28. Two DNOs expressed concern that inclusion with the price control may increase the risk of stranded costs associated with new EHV connections where the consumer requirement differed significantly from the existing EHV consumer base.

3.29. Respondents to the December document expressed general support for the publication of additional information relating to the EHV charging methodology but not for Ofgem to provide guidance in this respect.

Ofgem's proposal

3.30. The arguments presented by DNOs against adopting alternative arrangements for EHV charges are not convincing. The options outlined in the December document do not preclude a DNO from setting cost reflective, locational or site-specific charges for existing EHV consumers. In addition, whilst the existing arrangements do provide some protection to EHV consumers, it is not as clear or transparent a form of regulation as inclusion within the price control. One option would be to formalise the existing requirement as an explicit, separate price control, but this does not appear to have significant benefits and would be onerous to develop. In the light of this, **Ofgem proposes to include EHV charges within the scope of the price control.**

3.31. Ofgem recognises that DNOs may be exposed to some risks associated with new connections and as such it **is proposed that charges for any new EHV connections made during the next price control period are treated as excluded service revenue until the next review in 2010, when Ofgem would expect to include them within the price control.**

3.32. Work will be taken forward to develop an appropriate revenue driver for EHV within the units distributed revenue driver.

Non-contestable connection charges

3.33. DNOs classify the various aspects of connections work as contestable and non-contestable. Although the extent of the contestable market differs across DNOs, only procurement of materials for new connection assets and installation of those assets are universally contestable at this stage. All DNOs reserve the right to treat certain activities as non-contestable (e.g. determining the point of connection) which are essential to the effective provision of connections. The December document consulted on whether consumers of non-contestable services need to be provided with some form of additional protection in terms of charges that they pay and the quality of service they receive.

Views of respondents

3.34. There was general support amongst respondents for the extension of competition in the connections area, but some DNOs highlighted that there were issues to be resolved with regards to their liability for independent contractors undertaking work on the distribution networks. DNO respondents did not see any need for connections work to be included within the price control, but two other respondents considered that connections work should be included. One of these suggested that both contestable and non-contestable work should be brought within the price control, until it is proven that a sufficient level of competition has been established in contestable work.

3.35. There was general support for the use of service standards within the connections market, so long as there was a limited number and they were both appropriate and proportionate to the service being provided. Two DNOs noted that there was no substantiating evidence of DNOs cross-subsidising their operations within the connections market, but one further respondent noted that if any such evidence was forthcoming, Ofgem should ensure adequate safeguards are put in place to prevent recurrence and it should ensure that any excess returns are returned to consumers.

Ofgem's proposal

3.36. Non-contestable connection charges effectively cover two main cost areas:

- network reinforcement; and
- services provided to parties seeking new connections (such as identifying the point of connection to the existing network).

3.37. Ofgem considers that effective competition, where appropriate, will provide the best protection to consumers. Network reinforcement associated with the provision of new connections is an activity that could be increasingly opened to competition. Ofgem, DNOs, and other independent connection providers (ICPs) have worked hard to reduce the scope of activities that remain a monopoly service. It is important that this work continues and that companies do not abuse their position in the market to distort the development of competition.

Ofgem does not propose to change the price control treatment of connection charges in respect of reinforcement for demand consumers for this price control.

3.38. Regarding non-contestable services directly relating to the existing monopoly network, it is important that consumers and ICPs have clarity about the charges that they are paying. At present, there does not appear to be an appropriate level of consistency either in the charging methods or levels, both across DNOs, and over time. On this basis, **Ofgem proposes to require DNOs to establish and publish a clear schedule of charges.** If it appears that DNOs are charging an excessive amount for the services that they are providing, Ofgem will take necessary steps to ensure that consumers are protected. Ofgem intends to set up a working group with DNOs and ICPs to discuss the issue further.

3.39. It is also important that consumers are provided with protection in terms of the quality of service that they receive from DNOs. **At present, voluntary standards of performance exist in relation to the provision of connection services – but only for new housing estates. Ofgem considers that these should be extended to cover all new connections** to help ensure that consumers are provided with appropriate protection in terms of the quality of service that they receive and that DNOs do not abuse their position in the competitive market.

3.40. **Ofgem does not intend to attach financial penalties to these standards at this point** but performance will be monitored and consideration given at the time of the next price control review to how best DNOs should be incentivised in these areas. If there is evidence of DNOs providing a poor quality of service to consumers or abusing their market position, Ofgem will take appropriate steps.

Other excluded services

3.41. There are also a number of other excluded revenue items under the existing arrangements – the proposed treatment for these is set out below:

- **top-up and standby charges** – relate to charges for maintaining network availability where the distribution system is not used for the bulk of the energy needs of the consumer. **No change to price control treatment is proposed;**

- **non-trading rechargeables** – relate to specific requests made by third parties for DNOs to carry out work on their distribution systems. These include requests to relocate plant and equipment to accommodate the needs of public authorities or developers. **No change to price control treatment is proposed;**

- **metering excluded charges** – relate to the additional costs incurred by the DNO in providing prepayment meters or more sophisticated metering solutions to large consumers. The treatment of metering excluded activities is being considered as part of the work on developing separate metering price controls and further thoughts will be published in the June 2004 initial proposals document; and

- **other minor activities and charges** – these relate to other services provided to third parties where they fall outside the scope of the normal distribution function remunerated through use of system and connection charges. **No change to price control treatment is proposed.**

3.42. Some DNOs have identified additional items of revenue that they consider should be excluded from the price controls. The most significant of these is the treatment of energy exported to embedded networks. To avoid the creation of perverse incentives and to protect consumers, **Ofgem proposes that the treatment of units distributed to embedded networks should be consistent with that for wheeled units, i.e. included within the scope of the price control.**

3.43. Ofgem also needs to consider the treatment of costs and revenues associated with networks that DNOs operate outside of their authorised area (i.e. 'out of area networks'). **Views are welcome on this issue.**

Business rates

3.44. The December 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 is analogous to taxable income) for all DNOs. Initial estimates are due to be produced by the end of May 2004. Following this decision the Office of the Deputy Prime Minister (ODPM) will set the poundage (or tax rate). DNOs have the right to appeal the RV and therefore have substantial influence over the outcome of these deliberations, although much less influence once RVs are finalised (following any appeals). Until it becomes clear whether DNOs have acted efficiently and appropriately in the current valuation process, Ofgem will not provide any reassurance on cost pass-through. Subject to further information being available, Ofgem would expect to make a decision on the treatment of rates in the June Initial Proposals.

Hydro-benefit

3.45. The December document explained that the Authority has taken steps to remove Hydro-Benefit from the price control for Hydro-Electric (HE). Hydro-Benefit was a cross-subsidy from HE's hydro-generation business, which had the effect of reducing distribution charges for HE's consumers in the North of Scotland. The Secretary of State has proposed legislation[10] 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.

Dealing with uncertainty, new obligations and costs

3.46. The December document explained that Ofgem's preferred way of dealing with uncertainty is to provide a suitable degree of flexibility in the price control arrangements – for example through the use of revenue drivers. Where revenue drivers cannot be used and companies have been exposed to substantial new costs, Ofgem has reviewed these on a case by case basis. In certain cases, it has written to companies and/or made statements in final proposals documents about how costs will be treated if efficiently incurred.

Views of respondents

3.47. There was strong support from DNOs for a formal mechanism (like that used by Ofwat) to accommodate cost uncertainty; comfort letters were generally not

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[10] "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).

considered as an adequate replacement. Reasons given in support of this stance focused on minimising uncertainty, avoiding the need for full price control re-openers and avoiding the possibility of ex post regulation of costs. One respondent noted that if DNOs were to be given protection against cost uncertainty, this protection should be even-handed, such that consumers benefit from any unanticipated gains in these areas.

Ofgem's further thoughts

3.48. The December document explained why it is not appropriate to introduce a formalised mechanism (like that used by Ofwat) to deal with new obligations and costs between price control reviews. It is also not appropriate to make an explicit allowance for 'uncertain costs' in setting the price controls as this exposes both DNOs and consumers to the risk that the allowance is wrong. Ofgem recognises that DNOs may need some protection that some allowance will be made for certain costs that arise between price control reviews – although this should be limited to a very limited number of specific cost items. Ofgem will need to consider the most appropriate way of providing this protection to DNOs – previously comfort letters and statements in final proposals have been used. If this continues to be the case then it will be important that the process and approach for making any allowances is transparent.

Duration of the price control

3.49. The December document indicated that the revised price control would be set for a duration of 5 years from 1 April 2005. All the respondents that commented supported this approach.

3.50. **Ofgem confirms that the duration of the revised price controls for the DNOs will be from 1 April 2005 to 31 March 2010.**

Incentive framework

3.51. It was outlined above that the existing price controls are based on a RPI-X formula which provides incentives to companies to operate and invest in the network. This section sets out Ofgem's further thoughts on the incentives provided under RPI-X and in particular on:

- the strength of incentives to achieve efficiency savings including the rolling adjustments for capex and opex;
- mitigating the incentives that companies have to reclassify costs between opex and capex; and
- the balance of incentives between opex, capex and output delivery.

Views of respondents

3.52. Five respondents made comments supporting increases in the strength of incentives. Two respondents focused on the argument that all the easy gains have been made, so that distributors need stronger incentives to motivate them to put in the necessary extra effort to make further savings. One of these respondents noted that incentivising distributors to make these savings was beneficial to consumers in the long run. One respondent considered that incentives to invest should be strengthened and that incentives to reduce costs should not be strengthened.

3.53. There was a clear division between the DNOs and non-DNO respondents on the issue of an eligibility test for the capex rolling adjustment. The non-DNO respondents all considered that there should be some form of eligibility test for DNO overspends to ensure that they have been efficiently incurred and have provided defined outputs. These respondents also voiced their concerns regarding the ability of DNOs to underspend their capex allowances at the potential expense of outputs.

3.54. DNOs had differing views on the possibility of linking the incentive payment for capex underspends to the actual level of allowed capex. Some DNOs considered that this would ensure that distributors were incentivised to submit realistic capex forecasts, but others considered that this introduced unnecessary complexities and ignored the inherent and inherited features of each network. One DNO also highlighted the need for a clear and unambiguous set of rules on how underspends will be evaluated in the forthcoming review.

3.55. DNOs were generally supportive of a rolling opex incentive scheme along the lines of that being used by Ofwat, where exceptional and atypical items are excluded, but they were split on the issue as to whether a multiplier should be used if benchmarking is to be based on frontier performance.

Retention period for efficiency savings

3.56. It is important that companies are provided with appropriate incentives to achieve efficiency savings. These incentives need to be balanced against incentives for output delivery and there is no evidence that the existing incentives need to be strengthened. Table 3.1 summarises what Ofgem has previously indicated for the treatment of efficiency savings.

3.57. Ofgem needs to consider the treatment of the benefits received by DNOs from asset disposals between 1 April 2000 and 31 March 2003. Ofgem believes that DNOs made significant asset disposals during this period – although this is not clear from the business plans submitted by the companies. If there have been significant disposals it would not appear appropriate that consumers should continue to fund these assets if they remain in the Regulatory Asset Value (RAV). Ofgem intends to investigate this issue further before taking any decisions.

3.58. The way in which the capex and opex rolling adjustments will work is set out in Appendix 1.

Table 3.1: Treatment of efficiency savings

Efficiency savings	Existing price control period	Next price control period
Opex	Companies will be able to retain the **benefits of incremental opex efficiency savings achieved during this price control from 1 April 2003 to 31 March 2005 for a fixed period of 5 years** (including the year in which the saving was originally made). **For opex savings made between 1 April 2000 and 31 March 2003 companies will be allowed to retain the benefits for the period of this price control only, i.e. up to 31 March 2005**. The way in which the opex rolling adjustment will work for this price control period is described in more detail in Appendix 1	**Companies will be able to retain the benefits of all opex efficiency savings for a fixed period of 5 years** (including the year in which the saving was originally made). Consideration needs to be given as to whether some form of eligibility test would be appropriate. Ofgem is also considering changing the definition of opex from 1 April 2005 (see below)
Operational capex	Companies will be allowed to retain **both the depreciation and cost of capital benefits** for all efficiency savings (other than in respect of meters) made during the whole of this price control period,	**Companies will be able to retain the benefits of all capex efficiency savings for a fixed period of 5 years** (including the year in which the saving was originally

	(i.e. from April 2000 to 31 March 2005) **for a fixed period of 5 years** (including the year in which the saving was originally made). This commitment is conditional on companies meeting their security and quality of supply obligations – upon which Ofgem will take a general view of companies' compliance. The way in which the capex rolling adjustment will work for this price control period is described in more detail below and an example calculation is shown in Appendix 1.	made). Ofgem is considering both reducing the incentives to defer investment and changing the definition of capex from 1 April 2005 (see below).
Asset disposals	Companies will be able to retain **the benefits of any asset disposals of operational capex for a fixed period of 5 years** (including the year in which the saving was originally made). [11]	As above for operational capex.
Non-operational capex	**All non-operational capex savings will be retained for the period of this price control only, i.e. up to 31 March 2005**.	As indicated in the June 2003 document non-operational capex will be treated as operational capex from 1 April 2005 and included in the RAV and as such the same considerations apply.

Definition of costs and incentives

3.59. Categorisation of costs as capex or opex varies substantially across DNOs and in some DNOs has changed over time – all, according to DNOs, within the requirements of UK accounting standards. Between reviews, once cost allowances have been set, DNOs have a strong incentive to re-categorise costs from opex to capex. This is because the incentives to reduce opex and capex are different. A one-off saving in opex is retained 100 per cent by the company. A one-off saving in capex currently leads to the company retaining the cost of capital and depreciation benefits for 5 years before they are passed back to consumers (under a rolling adjustment mechanism), so that in present value terms, the company 'bears' about 40 per cent of the change. This means that reallocating £1 million of costs out of opex into capex will increase profits by £1 million, at the expense of bearing the cost of capital and depreciation on the resulting capex for 5 years (about £0.1 million a year) – leading to a present value benefit to companies of around £0.6 million. Given this incentive, it is clear that companies will be pushed towards capitalising costs.

3.60. Experience has shown that is very difficult to set out prescriptive definitions of capex and opex that will be consistently adopted by all companies and over time. A significant amount of resources (Ofgem's and companies') have been employed in making adjustments for capitalisation policy during this price control review. To mitigate the impact of this problem Ofgem is considering changing the existing treatment of costs so that:

- where types of costs are substitutes (e.g. refurbishment after a fault or at other times), incentives should be equalized as far as possible; and
- where definitional boundaries are difficult to set or enforce, incentives should also be equalized as far as possible.

3.61. The main impact on existing arrangements implied by these changes would be to treat all costs associated with faults (and perhaps also repairs and maintenance) in the same way as replacement capex, i.e. so it is all capitalised and included in the RAV. This would leave overhead costs to be treated as opex. As explained previously, Ofgem intends to capitalise non-operational capex from 1 April 2005 (e.g. IT spend) and depreciate it over a five year period. Ofgem considers that if costs are classified in this way it would be easier to monitor and the incentives that companies have to reclassify costs will be weakened.

3.62. Ofgem will continue to look at the dividing line between these categories of costs to ensure that a robust boundary can be drawn, monitored and enforced. If necessary Ofgem would consider equalizing the incentives further if it became clear that this could not be achieved.

3.63. One impact of these changes would be, all other things equal, to increase the amount of costs being capitalised and included in the RAV. In order to mitigate the cash flow impact of this change it would need to be offset by increased and accelerated depreciation allowances. **Ofgem welcomes views on this suggestion.**

Incentives for investment deferral

3.64. One of the most common ways of reducing capex is to defer investment and this may be an efficient approach where it can be achieved with no impact on

[11] Companies can only dispose of relevant assets in accordance with SLC 29, "Disposal of Relevant Assets"

outputs delivered However, it is difficult to distinguish between deferral that is efficient and that which is:

- derived from the regulatory process by companies submitting inflated capex forecasts. There will always exist an information asymmetry between a company and the regulator, to which some companies may respond by building a margin into their cost forecasts; or

- potentially at the expense of output delivery (including the longer term condition of the network). There is an imperfect understanding of the link between capex and outputs (in part because of the time lag between expenditure and effect). This means that concerns regarding the strength of incentives to defer investment cannot be solely addressed through output regulation – although it could help to some extent; or

- achieved by companies at the 'expense' of future expenditure. There are concerns that consumers could end up paying twice for investment projects as companies resubmit deferred (or similar) projects at the next price control review.

3.65. One option therefore would be to reduce the incentives that companies have to defer investment from April 2005 onwards. This could be achieved in a number of ways – perhaps the simplest of which would be to allow DNOs to retain only the cost of capital benefit in calculating the capex underspend incentive payment. This would reduce the present value of a £1 capex saving retained by the companies from around 40 pence to 25 pence.[12] **Ofgem welcomes views on this issue.**

3.66. The issue of investment deferral may be more acute where companies have submitted high capex forecasts. Several DNOs have expressed a willingness to have closer monitoring of their capex programmes, but none have suggested appropriate outputs that could be used to incentivise the investment**. Ofgem continues to invite practical suggestions as to how better to link capex incentives with outputs and take account of differences in capex forecasts across companies.**

Treatment of capex overspends

3.67. It is important to consider how to treat any capex overspends that DNOs incur over the next price control period. Ofgem published an open letter earlier this month on the gas distribution price controls[13] which included its thoughts on the treatment of capex overspends – similar considerations apply to the DNOs:

- if there is clear evidence of wasteful and unnecessary spending then this will not be included in a licensee's RAV;
- if costs are higher than allowed at the last price control review, but are nevertheless consistent with efficient spending, in general there will be a symmetrical treatment of under and over spend. Therefore a company could expect to have to meet at least the return element of financing costs of any overspend for a full five year period – after the elapse of this period the amount of the overspend would be added to the RAV; and
- where costs are higher, consistent with efficient spending, and this can be clearly shown to provide significant benefits to consumers (e.g. in being essential for security of supply), Ofgem would consider allowing the company to recover the regulatory depreciation and return from the year the expenditure is incurred.

Losses

3.68. Approximately 6 to 7 percent of electricity is lost as it is transported across distribution networks. The existing distribution price controls include an incentive on DNOs to manage losses, with an incentive payment/penalty of approximately 3p/kWh applied to the difference between the level of recorded losses and an allowed level based on a historic benchmark. In October 2003[14], Ofgem set out further thoughts on revised incentive arrangements from 1 April 2005. This included:

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[12] Based on a 6.5 per cent cost of capital.
[13] "Gas Distribution Price Controls", Ofgem, 16 March 2004
[14] p16-19, Electricity Distribution Price Control Review, Update October 2003 (124/03).

- moving to a fixed percentage losses target that would apply for the five year period of the price control, based upon the latest 10 year average; and

- adopting a rolling mechanism to make the receipt of benefits or penalties independent of timing of a change in losses.

Views of respondents

3.69. Respondents discussed a range of issues related to the development of the losses incentive. There were mixed views on whether the embedded generation saved losses adjustment should be retained, removed or modified. Other issues raised included the importance of the interaction between the losses and capex incentives, the treatment of non-technical losses and settlement errors and adoption of a fixed target.

Ofgem's proposals

Incentive mechanism

3.70. The target level of losses will be based on a proportion of units distributed and will be fixed for five years[15]. The fixed proportion will reflect the historic performance of the DNO, as measured by the aggregate volume of units lost as a proportion of aggregate volume of units distributed between 1994/95 and 2003/04.

3.71. DNOs have expressed concern that measurement errors following the introduction of competition in electricity supply to domestic consumer may unduly distort the level of the benchmark. However, Ofgem considers that this issue is primarily one of timing of the recording of units over the initial period since 1998 rather than affecting the aggregate volumes. As discussed in previous documents, Ofgem expects settlements data volatility to reduce in future years.

3.72. During the period for which the target is fixed, the DNO will be exposed to the aggregate effect of the previous changes in recorded losses. The rolling retention

[15] This would provide a retention rate broadly consistent with that for capex. If there are significant changes to the capex incentive, the length of the fixed period may need to be adjusted.

mechanism will make adjustments in the years after the target has been revised to ensure that the DNO is exposed to the impact of each incremental change in losses for five years independent of the timing of the change in losses.

3.73. Where expenditure to reduce losses is efficient, it will be allowed in the RAV after five years.

3.74. Further information is set out in Appendix 2.

Derivation of reported losses

3.75. Over the past few months, Ofgem has discussed the calculation of reported losses with each of the DNOs. This has revealed a number of differences between companies (even in the same corporate group) in the calculation of adjustments, including some that do not appear to be appropriate. Ofgem therefore considers that the current arrangements need to be revised to remove or redefine the adjustments. With one exception (below), there does not appear to be a strong rationale for retaining the adjustments.

3.76. **Ofgem therefore proposes that reported losses should simply reflect the difference between the estimated volume of electricity entering and exiting the distribution system.** This is consistent with the proposed scope of the price control and will result in the removal of the adjustments for EHV consumption, wheeled units and embedded generation saved losses. In addition, the adjustment for units consumed on own premises will be removed.

3.77. Several DNOs have expressed concern about the potential impact of large and/or multiple generation schemes locating or clustering in remote locations. It has been suggested that there are significant risks that the adverse impact on losses may more than offset the benefit of the distributed generation incentive scheme set out in Chapter 5. **Ofgem considers that some form of limited protection is appropriate.**

3.78. Ofgem intends to make an adjustment to the level of reported losses to reflect the impact of distributed generation with a loss adjustment factor (LAF) below a minimum level. Ofgem proposes that the minimum level should be set to

0.99.[16] At this level, the benefit from the DG incentive scheme would be matched by the cost imposed by the negative impact on the losses incentive. Ofgem will consider any alternative arrangements proposed by respondents in developing the initial price control proposals in June 2004.

3.79. It is envisaged that the adjustment would be the aggregate product of the difference between the site-specific LAF and the proposed minimum LAF, multiplied by the export volume of the generator. Ofgem intends to gather information on the current level of this adjustment in order to identify future incremental changes in losses.

Transitional arrangements

3.80. Several DNOs have noted that it will be necessary to consider transitional arrangements in view of the changes proposed to the form and structure of the incentive. Moving to the revised arrangements may provide windfall benefits or impose unanticipated penalties for some DNOs for performance under the existing arrangements.

3.81. Ofgem intends to write to DNOs in April to discuss issues surrounding the transition between the two incentive regimes. In light of these discussions, Ofgem intends to set out proposals on transitional measures in the June 2004 initial proposals document.

[16] This is based on the following assumptions – distributed generation incentive rate of £1.50/kW/annum; a generator generating for 3000 hours a year and a value of the losses incentive between 3p/kWh and 5p/kWh.

Price control for metering services

3.82. The December document Ofgem set out its further thinking on the metering aspects of the price control and confirmed that a decision had been taken to separate metering and distribution price controls.

3.83. Ofgem has been working with the distribution network companies to explore possibilities for the implementation of the various options and proposals identified in the December document.

Views of respondents

Stranding

3.84. A number of DNOs indicated that DNOs should be protected from the stranding of meter assets. Two respondents requested that a termination fee should be included in the price control.

3.85. Several DNOs urged Ofgem to ensure that all DNO costs associated with meeting their licence obligations in regard to metering were recovered. A DNO suggested that the fixed costs of metering should be recovered through the distribution charges. However, one supplier argued that DNOs should not be shielded from competitive market pressures by having their costs protected.

Form of Price control

3.86. Several respondents supported the proposal for a price cap on Meter Asset Provider (MAP) activities. Two respondents supported the proposal for an average revenue cap for Meter Operator (MOp) activities. However, several respondents gave support for the use of price caps in relation to MOp. Two of these respondents indicated that the price cap should only apply for some metering activities with the other activities not being price controlled. One DNO indicated that there was no need to have a price control for MOp as of 1 April 2005.

Competitive Market Review

3.87. One DNO indicated that the competitive market review (CMR) should focus on the capability of suppliers to switch rather than on suppliers' views of whether a price control remains necessary.

3.88. A DNO indicated that quantitative data may be of limited usefulness in relation to a CMR in metering. To this respondent it is more important that the CMR consider the extent to which suppliers and meter service providers respond to continued obligations on distribution companies rather than an absolute measure of market shares.

Other Metering

3.89. One respondent was concerned that the concept of a basic domestic meter remains undefined. The respondent is concerned that this will not be as easy a process as defining meter types in gas.

Ofgem's further thinking

3.90. In the July metering document, Ofgem dismissed the option of price controlling half hourly metering and the option of price controlling industrial and commercial (I&C) and non-half hourly (NHH) metering whilst not price controlling domestic metering.

3.91. The December document indicated that Ofgem was minded to introduce price caps for the provision of 'basic' domestic meters and non discrimination provisions in relation to other MAP activities. Responses to the December document were broadly supportive of this approach and Ofgem is intending to continue with it.

3.92. The December document suggested using an average revenue cap for MOp activities. Some respondents to the document supported this approach whilst others suggested using a price control for certain activities and a non-discrimination provision to cover the rest of these activities. Ofgem is continuing to actively explore both of these options.

Non-discrimination provisions

3.93. In its simplest form a non-discrimination provision is a licence requirement that the methods used by the DNOs in calculating their charges for price controlled and non-price controlled services should be non-discriminatory. Effectively this makes the price restrictions act as an 'anchor' for the prices of other services keeping the prices down without the need for more explicit regulation. A non-discrimination provision would allow the charges to vary to reflect differences in underlying costs.

3.94. A more explicit version of a non-discrimination provision is to require the DNOs to establish a charging methodology for metering services which must be approved (or at least not-vetoed) by Ofgem. The DNOs would then be obliged to charge in accordance with that methodology. Similarly to the non-discrimination provision this approach would provide an 'anchor' on metering charges through the price control but would give greater clarity on whether changes in charges are justifiable. It would however achieve this at the cost of a greater upfront level of work by DNOs and Ofgem in establishing the initial methodologies.

3.95. Some DNOs have suggested that a charging methodology would be sufficient to protect the interests of purchasers of metering services without the need for metering price controls. Ofgem has not ruled out this option.

Average revenue caps – revenue drivers

3.96. In order to have an average revenue cap it will be necessary to find a revenue driver (or a small set of revenue drivers) that explain a significant proportion of the variation in DNO charges. Initial discussions with DNOs have indicated that the number of visits, subdivided by domestic credit meter visits, domestic prepayment meter visits and I&C meter visits may be an adequate revenue driver. Ofgem will be conducting regression analysis to consider options for different revenue drivers.

Basic metering services

3.97. If the DNOs were to only be price controlled for basic metering services it would be necessary to place an obligation on them to provide these services as otherwise they could avoid price restrictions by making a small change to their service offering and thereby be without price regulation. Such an obligation could be in addition to, or as an alternative to, the general licence obligation to provide metering services. It is likely that such an obligation can be imposed under the current licence arrangements since Ofgem would be minded, when determining a dispute under Condition 36C of the distribution licence, to settle the terms of an agreement in such a way that the basic service has to be offered at, or below, the price controlled price.

3.98. In order to price control basic metering services it is necessary to have a clear definition of what constitutes basic metering. The policy intention underlying the proposal to only price control basic metering was that it would allow the DNOs to charge whatever price they could sustain in the metering market if they provided innovative services.

3.99. Given the policy intention set out above one method of defining a basic metering service would be to use a definition linked to historical practice. For instance if the basic meter were defined as "a meter of that type (for a given phase, voltage and number of registers) which the licensee provided at 1 April 2003".

3.100. An alternative would be to provide an explicit definition of what a basic meter is. One such definition could be derived from the technical standards needed for a meter to be accredited under the Electricity Act 1989. However this approach would potentially lead to a definition of a "basic" price controlled service that does not relate to anything the DNOs currently provide or intend to provide.

3.101. There is an additional complication in relation to prepayment metering. For historical reasons different technologies (key, card and token) are used in different distribution services areas, and have significantly different costs associated with them. An approach that uses a basic prepayment metering technology for price control purposes would probably need to be defined so that at least three different basic prepayment technologies were covered by the definition unless companies were required to change the prepayment technology they provided to the single agreed defined type.

Views invited

3.102. Views are particularly invited on the:

- weighting of EHV units in the revenue driver;
- treatment of DNOs' out of area networks;
- treatment of losses;
- definition of costs;
- incentives for investment underspend, including practical ways of linking capex incentives with outputs and taking account of differences in capex forecasts across companies; and
- the approach to metering.

4. Quality of service and other outputs

Introduction

4.1. The December document set out Ofgem's thoughts in a number of areas covering quality of service and other outputs that DNOs may be required to deliver over the next price control period and beyond. This Chapter sets out Ofgem's further thoughts on these issues. Where, possible this Chapter sets out firm positions on the structure of the incentive and monitoring regimes. However, some of the potential changes, including the level of some of the targets and incentives, will depend on the:

- willingness of consumers to pay for improvements. This is currently being assessed through a consumer survey, the results of which will be published in May 2004;
- efficiency of existing performance, which will be reviewed when 2003/04 actual performance data is available; and
- cost of making improvements. Ofgem is in the process of analysing the forecast cost information that has recently been submitted by DNOs which sets out the DNOs' expected costs of making improvements in quality of service.

4.2. These issues will be addressed in detail in the June initial proposals document.

Guaranteed and Overall Standards of Performance (GOSPs)

4.3. GOSPs cover a range of service areas including restoration of supply following unplanned faults, making and keeping appointments and the provision of new connections. Guaranteed Standards provide protection to individual consumers. If the DNOs fail to meet the required level of service they must pay compensation to the consumers affected, subject to certain exemptions. Overall Standards require DNOs' average level of performance for particular services to be above a minimum level. This price control review provides an opportunity to review the role, scope and form of the standards and the December document set out Ofgem's views on ways in which the GOSPs could be changed from 1 April 2005.

Views of respondents

Severe weather standard

4.4. Most respondents supported the interim arrangements and welcomed the intention to put longer-term arrangements in place but felt it would be premature to propose any changes for the next price control period.

4.5. A small number of respondents believed that severe events should be removed from both the Information and Incentives Project (IIP) incentive scheme and the guaranteed standards regimes to prevent the risk of double jeopardy. Opinions were divided on the proposal to introduce additional guaranteed standards in severe weather circumstances.

Increased compensation for business consumers

4.6. DNOs were generally against the principle of tightening the supply restoration standard for business consumers, particularly for those connected above a certain threshold. Many pointed out that business consumers choose their security of connection when they connect to the network, and that this can be reviewed with the DNO at any time. There was general support for increasing the notice period for planned supply interruptions.

Automatic payments

4.7. Two DNOs considered that the introduction of automatic payments for all consumers would be prohibitive in terms of costs but supported the idea of being more proactive in increasing consumer awareness of the standards, whilst placing the onus on consumers to make a claim. Another noted that there was no evidence of willingness to pay for automatic payments. One DNO thought that the provision of an automatic payment service would be an achievable goal in the forthcoming regulatory period, while another supported the introduction of "semi-automatic" payments.

Priority service consumers

4.8. Most respondents considered that introducing different service standards for priority consumers would be both undesirable and impracticable, primarily as most priority consumers are embedded in the LV network alongside non-priority consumers. energywatch considered that DNOs could offer better services to priority consumers through liaising with local authorities, such as health authorities.

Scope of exemptions

4.9. Most DNOs argued that the industrial action exemption should remain within the exemptions framework, many citing that its removal would increase risk within the regulated business. NGT, as well as some DNOs also argued that removing this exemption may significantly alter the balance of power in trade union negotiations, which may be detrimental to consumers. However, one DNO welcomed Ofgem's proposal to clarify the exemptions, suggesting that the industrial action exemption could be tightened by introducing a threshold of materiality if the action lasted longer than a given period, for example 5 days. energywatch supported Ofgem's review of the scope of exemptions.

Future of overall standards

4.10. There was broad support across DNOs and by energywatch for the removal of the overall standards and replacing them with some additional reporting requirements under the IIP Regulatory Instructions and Guidance (RIGs). However, one respondent did not feel overall standards needed to be subsequently incorporated within the IIP mechanism. Another respondent expressed continued support for overall standards as an appropriate mechanism for defining minimum consumer service levels and did not consider that the general meeting of the requirements meant that they should be changed.

Ofgem's further thoughts

Guaranteed standard on supply restoration

4.11. Ofgem considers that the supply restoration standard (GS2) could be separated to cover normal and severe weather conditions – which will build on the interim arrangements introduced in 2003 following the storms in October 2002.

4.12. Under normal conditions, if supply is not restored within 18 hours following a supply failure, consumers would be entitled to compensation of £50, with further payments of £25 for each successive period of 12 hours thereafter (i.e. consistent with the existing GS2 arrangements).

4.13. The arrangements under storm conditions are discussed in the section on network resilience.

Automatic payments

4.14. A change to current arrangements is proposed to ensure that DNOs do not have an incentive to discourage claims under the 18 hour restoration standard. It is proposed to address this by including an equivalent penalty under the quality incentives for any consumer off supply for more than 18 hours where payment is not made.

4.15. **Ofgem considers that DNOs should pay out automatically where possible and proactively contact consumers in general to make them aware of their right to compensation under the guaranteed standards framework where there has been a breach** (i.e. move to a 'semi automatic' payment mechanism). Subject to satisfactory introduction of these arrangements, Ofgem does not consider that full phase connectivity is necessary or that automatic payments are practical for the multiple interruption or planned interruption standards.

Compensation for business consumers

4.16. It is not clear that the current levels of compensation under the supply restoration standard provide sufficient remedy for the inconvenience for a loss of supply for the very largest business consumers – the results from the first stage of the consumer research would appear to support this.[17]

4.17. However, given that most business consumers are connected to the same network as domestic consumers, it would not be appropriate to differentiate between domestic and lower voltage connected business consumers. As such, the compensation payments and timeframes for restoration will remain the same for these two groups of consumers.

4.18. Ofgem does consider that there are differences between lower voltage connected consumers and those connected at HV and above, and arrangements for the latter group should be considered in the light of the willingness to pay survey.

Priority Service Consumers

4.19. DNOs have important licence obligations in respect of vulnerable consumers. Ofgem is working with the DNOs and suppliers to review and improve the arrangements to meet these obligations – and encourages DNOs to learn from best practice in this area. This work includes reviewing the effectiveness of the Priority Service Register.[18] Ofgem will need to consider the results of this review in deciding whether current licence obligations in respect of priority consumers remain appropriate. In the light of this work, and responses to the December document, **Ofgem does not consider that the most effective approach would be to introduce a new Standard of Performance focused on vulnerable consumers.** Other measures are being explored, including the potential for DNOs to introduce a dedicated helpline for such consumers – this will be informed by the consumer survey.

The role of the overall standards of performance

4.20. Ofgem considers that overall standards have served a very useful purpose in protecting consumers since their introduction at privatisation but have been

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[17] "Expectations of Electricity DNOs & WTP for Improvements in Service: Stage 1 Quantitative Research Findings", Accent Marketing and Research on behalf of Ofgem, September 2003.
[18] The Priority Service Register is a requirement of SLC 37 of the electricity supply licence . See the December 2003 report, "Priority Service Research Project: A report on services to priority consumers". Ofgem intends to issue guidance in due course on how priority service consumers are categorised.

superseded by the new quality of supply incentives under the IIP and the associated monitoring and reporting framework under the IIP Regulatory Instructions and Guidance (RIGs). Ofgem considers that it will be important to retain some of the Overall Standards (OS) reporting requirements within the overall framework and considers this is best achieved through adding these to the RIGs. This is further discussed in the section on outputs and incentives. If reported performance shows notable deterioration, Ofgem will investigate and retains the prerogative to re-introduce overall standards, or introduce new overall standards, if appropriate.

Other amendments to the Guaranteed Standards of Performance

4.21. **Ofgem considers that, in general, the existing suite of guaranteed standards provide sufficient incentives to DNOs to deliver good levels of consumer service and an appropriate level of compensation** where these levels are not met. However, Ofgem is considering the appropriate level of the multiple interruptions standard, which will be informed by the information from the willingness to pay study.

Reviewing IIP

4.22. The October 2003 update document and December 2003 consultation paper set out options for introducing new or revised output measures and for developing the quality of service incentive scheme. This section sets out Ofgem's initial proposals in these areas. Where possible, it sets out firm positions on the structure of the incentive and monitoring regimes. However, some of the potential changes depend on further work which is currently being undertaken.

Views of respondents

Scope of output measures

4.23. DNOs generally supported the aims of reporting disaggregated information within IIP. However, a number of DNOs suggested that there would be additional costs involved in collecting and reporting this information.

Worst served consumers

4.24. Of those that responded, one DNO argued that the existing multiple interruptions standard is an inappropriate measure, as in a single year, a proportion of consumers will experience a high number of faults from a combination of unrelated sporadic events. As such, they believed the standard should be measured over five years. Another DNO believes that the multiple interruptions standard goes a long way toward adequately protecting this group of consumers.

Form of incentive scheme

4.25. There was broad support among DNOs for moving to a scheme with rewards and penalties in each year, with the amount at risk to the scheme remaining at 2 per cent of price control revenue. One DNO argued that the marginal rewards should be higher than the marginal penalties because the balance of risk is becoming increasingly asymmetrical. The majority supported the introduction of deadbands over rolling average performance, although one DNO indicated that it was concerned that significant deadbands would overly complicate the incentive regime and result in a non-linear relationship between performance and rewards and penalties. energywatch commented that using deadbands could dampen incentives on DNOs to meet their targets and may complicate the scheme.

Planned interruptions

4.26. Most DNOs considered that planned interruptions should be excluded from the incentive scheme going forward. One DNO suggested that if separate targets for planned and unplanned interruptions can be achieved, then to give flexibility to the IIP, they could be rolled back together without explicitly targeting either. However, they commented that if this is not possible, then planned interruptions should be excluded.

4.27. A number of DNOs expressed concern at changing the IIP rules to allow companies to roll forward a number of customer interruptions (CIs) and customer minutes lost (CMLs) in the current scheme. Three respondents considered that adjusting the current IIP mechanism, which is presently symmetrical in its last year of operation, is neither appropriate nor practical and is inconsistent with the principle of 'no retrospection regulation'. energywatch explained it would welcome further detail on how Ofgem would calculate the interest rate to be applied to any CIs and CMLs rolled forward.

Ofgem's further thoughts

Provision of disaggregated interruption data

4.28. Ofgem proposes to modify the RIGs to include the following reporting requirements:

- disaggregated data on the number and duration of interruptions by HV circuit and other related circuit information which has been used for the work on comparing quality of supply performance; and
- disaggregated data on the number of consumers interrupted by the following duration bands: 3 minutes – 1 hour, 1-2 hours, 2-3 hours, 3-6 hours, 6-12 hours,12-18 hours, 18-24, 24-48 hours and over 48 hours.

4.29. **Ofgem does not propose to introduce performance targets in respect of these measures at this review.**

4.30. The additional costs of reporting this information should be relatively small as the HV circuit data is already reported on an informal basis and information on numbers of consumers interrupted by duration band involves extraction of existing data in a different format. Ofgem, therefore, does not propose to provide a specific allowance in this area. The draft changes to the IIP RIGs are set out in an accompanying document.

Worst-served consumers

4.31. Ofgem considers that it is important to introduce an output for worst-served consumer to monitor whether incentives to improve average performance are having a detrimental effect on such consumers. **Ofgem proposes to modify the RIGs to introduce a new requirement for reporting the number of consumers experiencing particular frequencies of interruption each year.** DNOs would be required to report the number of consumers experiencing zero higher voltage

(HV) interruptions, rising in single increments up to the number of consumers experiencing ten HV interruptions. DNOs should also identify the number of consumers experiencing more than ten HV interruptions.

4.32. This measure should not impose significant additional costs on DNOs as it would replace the existing overall standard on multiple interruptions. **Ofgem does not propose to introduce performance targets in respect of this measure for the next price control period.**

4.33. Consumers will also receive protection through the existing guaranteed standard on multiple interruptions.

Connections

4.34. Given the proposed removal of the overall standards of performance, Ofgem considers that it is appropriate to transfer the existing reporting requirements for the percentage of domestic (non-domestic) connections provided within 30 (40) working days to the outputs framework.

Form of the incentive scheme

4.35. **Ofgem proposes to retain the incentive scheme for the number and duration of interruptions but move to annual rewards and penalties**. The size of the incentive will be informed by the results for the consumer survey. This will be addressed in the June initial proposals document. Ofgem is not minded to introduce deadband or rolling averages. Subject to introduction of proposals set out below under network resilience, severe weather events will be excluded. The current arrangements will continue for other exceptional events (i.e. potential exclusion subject to the DNO taking appropriate mitigating actions).

4.36. Further consideration is being given to whether annual rewards and penalties should be logged up into a single adjustment at the end of the next price control period or whether they should be used to adjust allowed revenues on an annual basis.

Weighting of planned and unplanned interruptions

4.37. At present planned and unplanned interruptions are given equal weighting in the quality of service incentive scheme. This may be inappropriate as consumers are given advance warning and have greater opportunity to mitigate the impact of planned interruptions. **Ofgem proposes to establish weightings taking account of the results of the consumer survey.**

Audits and adjusting data for inaccuracy

4.38. Ofgem is considering 2 options for the audit framework for the next price control period:

- Ofgem carrying out a "streamlined version" of the existing audit process for each DNO on an annual basis to verify the accuracy of their interruption data. DNOs would face a pre-determined penalty if their reported data failed to meet the accuracy targets; or

- requiring the DNOs to carry out and report the results of annual audits of their interruption data based on Ofgem's methodology. In addition Ofgem would carry out random audits on a small number of DNOs each year to verify that the information is reported correctly. The DNOs would face an increased penalty and a further Ofgem audit the following year if their reported data failed to meet the accuracy targets.

4.39. **Ofgem welcomes views on this issue.**

4.40. At present DNOs' reported data for interruptions is only adjusted if the audit results show that it is less than 95% accurate overall or less than 90% accurate at LV. This means that some DNO's rewards and penalties may be based on inaccurate data. **Ofgem proposes that in the next price control period performance data should adjusted for any inaccuracies identified by the audits.**

Target setting

4.41. It was explained above that the targets under the incentive scheme will be addressed in the June initial proposals.

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

4.42. Ofgem considers that there is a significant risk that some DNOs may inefficiently defer planned work and the associated CI and CMLs in 2004/05 in order to improve their performance relative to their targets. This would result in reduced penalties or increased rewards for outperformance under the quality of service incentive scheme. **Ofgem proposes that DNOs should be allowed to roll forward up to 2 planned CIs and 3 planned CMLs from 2004/5 to 2005/6 to mitigate this incentive.** An 'interest rate' of 6.5 per cent will be applied for this roll forward to ensure that DNOs are not unduly advantaged. DNOs that wish to take advantage of this mechanism will be required to commit in writing by 30 April 2004, before decisions about targets for 2005/06 are announced.

Frontier performance

4.43. As set out in the October 2003 update document, those companies that are currently best performers on quality relative to the disaggregated benchmarks will be eligible to participate in the reward mechanism of the current IIP arrangements whether or not they meet both their targets for the number and duration of interruptions in 2004/05.

Network resilience

4.44. This section sets out Ofgem's further thoughts on network resilience in the light of respondents' views, the work that has been undertaken in the Ofgem-DNO quality of supply working group, discussions with other parties including the Met Office and work undertaken by our consultants.

Views of respondents

4.45. Five DNOs set out that there are no robust models for mechanically linking weather to restoration performance assessment and further that benchmarked performance during different types of weather events is not practical. A number or respondents expressed support for working toward understanding better the relationship between network performance and severe weather.

4.46. Two respondents believe improved storm resilience to be only quantifiable for the foreseeable future in terms of delivery of inputs, such as the replacement of certain assets. Three DNOs stated that the most realistic option to measure the ability of a company to respond to an exceptional event is to use ex-post performance assessment, while one respondent felt it was not possible to make a meaningful comparison.

4.47. The inclusion of exceptional event performance in IIP was considered, generally, to be inappropriate, as it would not promote improvements in the ability of a network to withstand severe weather events. One respondent considered that the existing incentives under IIP, in addition to the guaranteed and overall standards are inadequate to quantify and incentivise resilience.

Ofgem's further thoughts

4.48. Ofgem has considered a range of approaches to measuring the ability of a network to withstand storms, including quantifying the relationship between storms and faults (or the number of consumers interrupted) and the extent to which network performance differs between "normal" and "storm" days. The main difficulties in developing such measures are that storms occur relatively infrequently and vary significantly in nature; and that there is limited availability of data. Given these considerations and timing constraints, Ofgem does not consider that it is possible to develop a robust incentive mechanism for the initial impact of a storm as part of this price control review.

4.49. Ofgem is carrying out an ongoing programme of work beyond the current price control review with the DNOs and other interested parties to develop appropriate measures of the ability of the networks to withstand storms and companies' performance in restoring consumers.

4.50. It is important however that DNOs have appropriate incentives in this area. Ofgem proposes to strengthen DNOs' incentive to restore consumers' supplies promptly following a severe weather event by refining the interim arrangements introduced in October 2003. Different arrangements will apply for different weather conditions; the scale of the event being defined by the amount of faults that occur and the proportion of consumers that are affected. These definitions will be developed subsequently and discussed in the June initial proposals document:

- **no severe weather -** the existing standard on supply restoration would continue to apply in "normal" weather conditions, i.e. when there is not a severe weather event. Domestic consumers are entitled to a payment of £50 after 18 hours off supply, and a further £25 for each subsequent 12 hour period. These payments are funded by DNOs and there is no cost recovery;

- **"smaller" severe weather event -** Ofgem is considering whether the trigger period for smaller severe weather events should be 24 or 30 hours. Consumers would receive compensation of £25 after 24/30 hours off supply and a further £25 for each subsequent 12 hour period. A DNO would bear the cost of these payments, whether they are made to consumers or not:

    - for those eligible consumers that do claim, the consumer receives the payment; and

    - for those eligible consumers that do not claim, the DNO's allowed revenue is reduced by the amount of the payment.

    There may be an element of cost pass-through up to 48 hours. Beyond this point the DNO would bear all of the costs. DNOs could even be incentivised to be proactive in making payments to consumers.

- **"larger" severe weather event -** the incentive arrangements for "larger" severe weather events would be the same as those for "smaller" severe weather events, except that the relevant trigger period would be 48 hours and that there may be an element of cost pass-through up to 72 hours. Beyond this point the DNO would bear all the costs; and

- **"very large" severe weather event -** As in the interim arrangements, for "very large" events, a discretionary approach would be followed. Ofgem would agree with DNOs the arrangements for compensation in these very extreme circumstances.

4.51. Whilst the new severe weather arrangements may increase DNOs' exposure to costs of making payments to consumers, Ofgem is proposing to treat DNOs' expenditure on fault costs (e.g. repairing faults, replacement of damaged equipment) as capital expenditure. Ofgem has also proposed to exclude all CIs and CMLs relating to severe weather from the IIP incentive scheme. The financial exposure of companies could be limited further by considering some degree of cost pass-through although this would result in recycling money between consumers. Ofgem is also considering the extent of any annual caps that may be placed on DNOs' exposure under this scheme and whether there should be a cap on payments to individual consumers. **Views are welcome on this issue.**

4.52. Ofgem is currently reviewing information provided by the DNOs on the costs of improving network resilience, including the costs of an accelerated upgrade to EATS 43-40. Ofgem's consumer research currently is also assessing consumers' willingness to pay in this area.

Incentives for telephone response

4.53. Under the existing IIP incentive scheme DNOs are rewarded or penalised by up to 0.125 per cent of their annual revenue depending on the relative quality of telephone response they provide to consumers who contact the company about a fault or an emergency situation and speak to a telephone operator. Companies' performance is assessed through a monthly consumer survey that is undertaken by Ofgem. DNOs also report information on the speed of telephone response but this is not subject to financial incentives in the current price control period.

4.54. This section sets out Ofgem's further thoughts on developing incentives in this area.

Views of respondents

Inclusion of automated messaging

4.55. Most DNOs - and energywatch - supported the principle of including consumers who received an automated message in the scope of the consumer survey. However, one DNO commented that this was not appropriate because consumers who are dissatisfied with the message will hold to speak to an agent and therefore will be included in the scope of the survey anyway.

Form of incentive scheme

4.56. Most DNOs supported moving to an absolute basis for assessing performance under the consumer survey. Some of these respondents suggested that the using absolute targets would eliminate any potential of regional bias affecting a DNO's relative reward or penalty under the existing scheme. However, one respondent considered that the incentive mechanism should continue on a relative basis while another urged Ofgem to consider abandoning the routine telephone surveys given that companies' performance is already very good and suggested these are replaced by occasional 'mystery shopper' surveys.

Including speed of telephone response in survey

4.57. A number of respondents supported including an assessment of the satisfaction with the speed of telephone response in the consumer survey, although one noted that although such a measure may not be robust enough for incentivisation, it may be used as an appropriate cross check with the information reported under the RIGs.

Ofgem's further thoughts

The survey sample

4.58. Under the existing incentive mechanism, the consumer survey covers consumers that speak to an agent with regard to power loss or an emergency. Ofgem consulted in the December paper on the possibility of expanding the scope to include calls answered by an automated message. There was general consensus among respondents that this would be appropriate and more representative of consumer satisfaction with the quality of telephone response.

4.59. However, some respondents suggested that there may be restrictions under the Data Protection Act to expanding the survey in this way. Ofgem has sought guidance from the Information Commissioner on this issue which suggests that there should be no data protection restrictions to obtaining and using information on consumers who calls are answered by an automated message.

This information should be disclosed to Ofgem and or its consumer research consultants in accordance with the relevant legislation.

4.60. Ofgem is currently reviewing potential technical constraints to expanding the scope of the survey. Subject to this issue being resolved satisfactorily, **Ofgem proposes the survey will be expanded to include consumers who have their calls answered by an automated message in the next price control period.**

Survey questions

4.61. Ofgem considers that the existing assessed attributes should remain incentivised. However, there may be scope for combining or rationalising some of the questions, for example combining the politeness and willingness to help questions into an overall 'helpfulness' question. Ofgem intends to work with DNOs and other interested parties such as energywatch to consider the appropriate form of the survey questionnaire. **Ofgem welcomes views on this issue.**

Combining quality and speed of telephone response

4.62. Ofgem has now received 4 months' data on the revised speed of telephone response key measures. A review of the data shows that there is variation in the results, including between DNOs that have the same type of generic systems. In light of this, it is unlikely that it will be possible to define, on a robust basis, a quantitative measure of the speed of telephone response.

4.63. However, it is clear that the speed of telephone response is an important output that consumers are concerned about. As such, Ofgem proposes to assess consumers' satisfaction with the speed of telephone response on a trial basis by including an additional question in the consumer survey from April 2004. The results from this additional question will be shared with DNOs as part of the monthly report, and will help inform Ofgem as to targets for performance.

Form of the incentive scheme

4.64. At present, DNOs are incentivised under a relative scheme, with performance scores ranked according to consumers' satisfaction with performance in 4 key areas. This type of incentive scheme has been effective in improving DNOs' performance.

4.65. The improvements have led to a narrowing of performance across DNOs with the spread of cumulative overall performance scores between 4.61 and 4.20 in the 12 months to February 2004. This convergence means that although all DNOs are scoring in excess of 4 (i.e. consumers are generally satisfied), some are being rewarded and some penalised.

4.66. The form of the incentive scheme will depend on the resolution of the technical issues mentioned above. It will be considered further in the June paper.

Environmental outputs

4.67. Ofgem has a statutory duty to have regard to the effect of the generation, transmission, distribution and supply of electricity on the environment. This requires a good understanding of the environmental impacts of these activities and reporting is an important step in managing environmental impacts.

4.68. Ofgem highlighted the importance of reporting in its Environmental Action Plan[19] and made a commitment to "...develop a small number of Key Performance Indicators (KPIs) for the gas and electricity sector". The price control will already require reporting of some measures that have an environmental impact – distribution losses and distributed generation. It is important to consider whether any other measures should be reported.

Views of respondents

4.69. There was general acceptance of the broader environmental responsibilities of DNOs and acknowledgement that there may be additional costs associated with meeting these obligations. However, four DNOs identified that environmental considerations are already covered by other agencies and felt that there may be a duplication of effort and resources if new reporting requirements are introduced. Two respondents were against any imposition of additional reporting requirements.

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[19] "Environmental Action Plan", Ofgem, August 2001.

4.70. One respondent welcomed an increase in reporting requirements on DNOs to report on specific ways in which they have met their statutory responsibilities including public consultations undertaken, number of lines placed underground and measures implemented to reduce visual intrusion

Ofgem's further thoughts

4.71. The aim of environmental reporting is to assess the current environmental performance of DNOs, identify long-term trends and highlight areas where further incentives may be appropriate. Ofgem proposes to introduce reporting requirements covering:

- sulphur hexafluoride (SF_6) – SF_6 lost, either by weight or some appropriate proxy such as number of top-ups and number of units of equipment with SF_6 installed;
- oil pollution – volume of oil lost from cables and number of reportable incidents and prosecutions;
- amenity issues – details of Schedule 9 statement including date of last review; and
- environmental management systems – details of ISO or other environmental management certification.

4.72. **Ofgem does not propose to introduce financial incentives on any of these output measures over the period of the next price control.**

4.73. These will be developed further in consultation with DNOs and other agencies such as environmental regulators but will be based as far as possible on data previously collected by DNOs – this will help to minimise any additional reporting burden. Changes to the RIGs to incorporate these measures will be consulted on separately.

4.74. It is important that the reporting process is transparent and it is proposed to publish the indicators, with appropriate commentary, on an annual basis. The exact format and content of the report will be discussed with the DNOs.

General discretionary reward

4.75. In general, Ofgem is moving toward more mechanistic quality of supply, telephony and resilience incentives. Given these developments, Ofgem considers it may be appropriate to introduce a separately assessed discrete reward for service performance in other aspects of how DNOs address the needs of their consumers. For example, this could encompass best practice towards priority consumers, effective communication during severe weather events with consumers and other parties such as the media, energywatch and local authorities. The reward could be assessed annually (or every 2 years) and would be set at a level that provides a meaningful, but not excessive, reward (e.g. £1 million to be awarded to a single DNO or shared between 2 or 3 companies as a discrete addition to their price control revenue. **Ofgem would welcome views on this.** If this initiative was to be taken forward, Ofgem would look to work with energywatch on the mechanics of the reward.

Undergrounding

4.76. Ofgem is currently reviewing information provided by the DNOs on the costs of undergrounding. The consumer survey that is being undertaken is also assessing willingness to pay in this area. This will be discussed further in the June initial proposals.

Views invited

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

- movement to a semi-automatic payment mechanism under the supply restoration standard;
- other changes to the standards of performance;
- the approach to severe weather and network resilience;
- environmental issues; and
- the introduction of a discrete reward for good performers in other areas.

5. Distributed generation, innovation funding and registered power zones

Introduction

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

5.2. The December document set out the framework of an incentive mechanism for DNOs to in respect of the connection of distributed generation to their networks. This included initial values for the level of pass-through and incentive rate for the costs associated with distributed generation (DG). This Chapter sets out Ofgem's proposals on the design of the incentive mechanism and the value of the parameters.

5.3. The Chapter also sets out Ofgem's proposals on the use of Registered Power Zones (RPZs) and the Innovation Funding Incentive (IFI).

5.4. Separate RIAs for the DG incentive scheme and IFI & RPZs have also been published alongside this document.

5.5. Ofgem has also published a report, produced by Mott-MacDonald & British Power International (MM-BPI), on the information submitted by DNOs on distributed generation.[20]

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

Incentive framework for distributed generation

5.6. The December document proposed the introduction of a 'hybrid' incentive scheme for DNOs in relation to the connection of distributed generation, the broad characteristics of which were that:

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

5.7. The objectives of the incentive scheme are to:

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

5.8. This section sets out Ofgem's proposals on the detailed mechanics of the incentive scheme – and in particular responds to the questions that have been raised by respondents to the December document. It also sets out Ofgem's proposals on the value of the parameters for the incentive scheme.

Views of respondents

5.9. The majority of the respondents were broadly supportive of the principles, general structure and approach of the proposed hybrid mechanism. They agreed that the DNOs should receive appropriate incentives to facilitate DG and be protected from undue risk. Two DNOs felt that the risks placed on them by the proposed mechanism would lead to a sub-optimal, short-term approach to network reinforcement.

5.10. A number of respondents commented that the proposed ranges of values for pass-through were broadly appropriate. Whilst one respondent did not support a high pass-through rate, some of the DNOs believed that the pass-through rate should be higher to limit their risks.

5.11. A number of other issues were raised by respondents particularly seeking clarification about the detailed mechanics of the incentive scheme.

Ofgem's proposals

Level of pass-through

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

5.13. The December document explained that an appropriate range for the level of pass-through commensurate with meeting the objectives for the incentive scheme was between 70 and 80 per cent. Although some DNOs have argued for a higher level of pass-through, Ofgem considers that the range of pass-through rate proposed in the December document provides a reasonable level of protection from risks for the DNOs and balances well with the incentives for efficiency. It provides incentives for DNOs to invest in a timely and efficient way to meet the demands of generators seeking connection to the network although it is not designed to encourage potentially inefficient expenditure where the use of assets is subject to a reasonable amount of uncertainty.

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

Recovery of pass-through costs

5.15. DNOs will be entitled to revenue under the incentive scheme as costs are incurred. Ofgem recognises that this may lead to DNOs under-recovering the pass-through element initially (until the generator begins paying use of system charges). However, Ofgem has indicated that it intends to put in place a deadband for over-recovery around the allowed level of price control revenue of

2 per cent per annum. In addition, any over-recovery will be assessed against total revenue recoverable (i.e. revenue from all users of the network – not just demand consumers).

From whom should the DNOs recover the allowed DG revenue?

5.16. **The total revenue that a DNO can recover under the DG incentive scheme (the pass-through and the incentive rate) should normally be recovered from those generators connecting to the distribution system after 1 April 2005** (except under certain circumstances outlined below). Further work is underway through the electricity distribution structure of charges project to determine an appropriate charging structure for generators.

5.17. The pass-through element, less any relevant connection charge associated with reinforcement, would be recoverable over the assumed asset life of 15 years on an annuity basis at 10.635 per cent each year[21], starting in the year after the expenditure is incurred.

Pass-through costs – treatment of "stranded assets"

5.18. Concerns have been raised about the ability of a DNO to recover its costs when:

- some, or all, of the expected DG volume associated with a particular project does not materialise after the DNO has carried out the investment for the connection; or

- some, or all, of the DG that connects to the distribution system ceases to operate (i.e. permanent operational closure of the generating facility) before the relevant DG assets are fully depreciated (i.e. before all costs are recovered by the DNO).

5.19. Under these circumstances, the charging base for Generation Distribution Use of System (GDUoS) is reduced (or becomes non-existent). This could mean that the DNO may not be able to recover its pass-through costs from the remaining generators connected to its network through GDUoS. In order to ensure that DNOs are at least able to recover their pass-through costs any resulting shortfall

[21] Assuming a cost of capital of 6.5 per cent.

(not recoverable from generators) will need to be funded by demand consumers in the DNO's authorised area (or areas). In these circumstances the incentive rate payment associated with the generator that has ceased operation (i.e. the £/kW allowance) will not be recoverable by DNOs. If the available capacity is utilised by another generator (including reactivation of the original generating facility) then the DNO will be allowed to recover the incentive rate payment. This will provide an incentive to the DNO to encourage other generators to utilise the available capacity which will help ensure that assets are used efficiently. If the capacity is utilised for demand, the DNOs will be permitted to reallocate 100 per cent of the costs (less any depreciation already recovered) to demand related capital expenditure – and therefore included in the RAV underlying the price control.

5.20. It will be necessary to define the appropriate trigger (i.e. level of GDUoS) that would mean that demand consumers would be required to fund a proportion of the pass-through costs. The RIA for the DG incentive scheme estimates that under a worse case scenario[22] the potential costs that could be funded by consumers would be in the region of around 42 pence per consumer per year for domestic consumers (or of the order of 1 per cent of distribution charges). The work on defining the trigger point for GDUoS will be taken forward as part of the project on structure of charges.

The value of the incentive rate

5.21. The initial incentive rates proposed in the December document were set on the basis of the average unit cost across all the DNOs as reported by the companies in the Distributed Generation Business Plan Questionnaire (DG-BPQ). As explained above, Ofgem and its consultants have reviewed the cost information submitted by the DNOs. Some adjustments have been made to companies' data but the overall conclusion of the consultants was that, given the variability in expected costs and the lack of detailed data from some companies, it would be appropriate to take the average reported costs across the industry to set the parameters for the incentive scheme.

[22] This has been defined as where 50 % of DG does not materialise once DNOs have incurred expenditure to accommodate it, or where the DG closes early before the assets are fully depreciated – pushing up the average cost to £100/kW (where the generators contribution is capped at £50/kW).

5.22. In the December document this resulted in an incentive rate of **£1.5/kW/yr associated with the 80% pass-through** (based on an additional rate of return of 1 per cent above the current allowed cost of capital of 6.5 per cent – i.e. 7.5 per cent). Based on the views of its consultants, Ofgem's own work and the cost information reported by the DNOs, this figure appears appropriate for the majority of the DNOs. One DNO, Scottish Hydro-Electric, has been allowed a slightly higher incentive rate to reflect the higher than average costs identified by Ofgem's consultants for connecting distributed generation to its network. This is shown in Table 5.1.

Table 5.1: Incentive rates with 80 per cent pass-through (excluding O&M)

DNO	Unit costs – shared & strategic capex as reported by DNOs £/kW	Unit costs used for calculating incentive rate £/kW	Incentive rate (excluding O&M) £/kW/year
Aquila	44 – 89	50	1.5
EME	14 – 59	50	1.5
EPN	51	50	1.5
LPN	47	50	1.5
SPN	37	50	1.5
NEDL	8	50	1.5
YEDL	10	50	1.5
SEPD	28 – 36	50	1.5
SHEPD	70 – 83	70	2.0
SPD	14	50	1.5
SPM	44	50	1.5
UU	28 – 44	50	1.5
WPD Swales	23 – 75	50	1.5
WPD SWest	22 – 74	50	1.5

5.23. It should be noted that the above incentive rates are calculated using the cost information based on a shallow connection boundary, i.e. the unit costs shown include all assets whose use is shared by more than one user and only exclude those on a topological spur to a single connectee. Connection charges paid by the generator in respect of shared costs will be subtracted from the DNOs' allowed revenue under the hybrid mechanism.

O&M costs and the final incentive rate

5.24. The December document indicated that figures provided by the DNOs showed a range for O&M costs, generally in the order of 1-2 per cent of the capital costs per year. The total costs of distributed generation – both sole-use and shared costs – have been identified by the DNOs to amount to around £82/kW. Rounding up to £100/kW and providing a 1 per cent allowance for O&M means that each DNO will be allowed to recover £1/kW to cover these costs. This is broadly consistent with the views of MM-BPI and the determination made by Offer in 1999 in relation to the O&M charges made by London Electricity.[23]

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

Recovery of the incentive rate

5.26. The incentive rate shown in Table 5.1 will be recoverable by DNOs once generating capacity connects to the distribution network and is only applicable whilst the generator remains connected to the network (i.e. continues to operate). DNOs will still be able to recover the incentive rate in instances where the generator decides to cease generating power temporarily (for example, due to weather and other conditions).

Locking-in the incentive rate

5.27. Ofgem has assumed that the asset life for capex associated with distributed generation will be 15 years. To ensure that DNOs have certainty about the amount of revenue that they will be able to recover over the life of the asset, **the incentive (excluding the O&M charge)** applying at the time of connection will remain in place until the asset is fully depreciated. Ofgem will reconsider the level of the incentive rate at the time of the next price control review (or possibly sooner if the levels set cause problems) and a different incentive rate may be applied – **but this will only apply to new generating capacity connected after any decision to change the incentive rate is announced.**

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[23] Offer Determination DET/R/869, 23 July 1999

Menu option

5.28. There was little support from respondents for the use of a menu option outlined in the December document – with most DNOs preferring the higher pass-through rate. Ofgem does not propose to use a menu approach.

Floor and cap on DNO returns

5.29. The cost information submitted by DNOs in the DG-BPQ shows a wide variation in the expected costs associated with connecting generators to the distribution networks. Some DNOs have argued that there is the possibility that, depending on the costs incurred, the rate of return that they achieve could be significantly below the average level upon which the incentive scheme is based (7.5 per cent). Ofgem recognises that this is possible but does not consider that additional protection should be provided to DNOs by increasing the ex ante pass-through rate as this would weaken incentives towards efficiency. As an alternative, Ofgem will set a floor to the rate of return on the overall portfolio of distributed generation connected in the next price control period, equal to the allowed cost of debt as specified by Ofgem in calculating the cost of capital.

5.30. To balance this, Ofgem also intends to cap the maximum rate of return on the overall portfolio of distributed generation connected in the next price control, to a level equal to two times the allowed cost of capital.

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

Strategic investment

5.32. The December document consulted on whether it would be appropriate to provide a higher incentive rate for 'strategic investment', i.e. investment ahead of realised generation connection applications). DNOs have generally argued that either a significantly higher incentive rate will need to be provided (one DNO suggested 3 times the 'normal' incentive rate) or that the company would need to be protected against all output risk (i.e. expenditure would be included in the

RAV at the allowed cost of capital regardless of whether the additional capacity was utilised by generators and/or demand consumers). Other DNOs indicated that they would be cautious about undertaking investment where the use of those assets was subject to a reasonable level of uncertainty.

5.33. Ofgem does not consider that it is in the best interests of generators or consumers (given the higher probability that such assets would be stranded) to provide incentives that would encourage them to undertake speculative investment where the DNOs considers that the risk the assets will not be used is substantial. The incentive scheme has been designed to encourage DNOs to accept some output risk in exchange for the possibility of a higher rate of return – which will be higher the more efficiently they connect generators. On this basis, no additional allowance will be made for strategic investment.

'High cost' projects

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

Microgeneration

5.35. The DG incentive is designed to encourage DNOs to facilitate DG. DNOs do not have an active role in facilitating individual microgeneration connections (they may only be told after they have happened) but could have a more general role in facilitating microgenerators as a class. It is therefore appropriate to consider whether or not the £/kW driver in the DG incentive scheme should apply to microgeneration connections.

5.36. If the DG incentive scheme did not cover microgenerators, DNOs would not have a financial incentive to facilitate their connection. Charges would be based on a view of likely reinforcement costs (net of benefits).

5.37. If the DG incentive scheme did apply to microgenerators, DNOs would have a financial incentive to facilitate their connection. Some DNOs may argue that charges should be based on the incentive rate including O&M (i.e. £2.50/kW) plus a view of likely reinforcement costs. Ofgem has not accepted this argument – particularly if the level of microgeneration becomes significant, Ofgem would expect that charges to reflect the costs and benefits which it gives rise to on distribution networks. Charging design will be considered further in the structure of charges consultation update due to be published in April. In addition, there may be increased implementation costs associated with monitoring the DG incentive scheme if it did apply to microgeneration. If microgeneration was not included, this would need to be reconsidered at the next price review.

5.38. **Views are invited on whether or not the DG incentive should apply to microgenerators** (i.e. whether the capacity should attract the £/kW incentive payment).

Incentives for ongoing network access

5.39. It is important that DNOs are provided with incentives to provide ongoing network access (availability) to generators once they have been connected. The December document suggested that an incentive of £0.002/kW/hr would be appropriate. The payment to generators would only be made in the instances where the DNO has failed to provide access to the network, not where the generator has chosen not to generate power (or is forced to cease generating due to weather or other circumstances). DNOs generally argued that it was not appropriate to provide incentives in this area whereas one other respondent argued the incentive should be much higher. Ofgem considers that an incentive should be provided but that it should not cover compensation for economic loss – but should focus DNOs on providing ongoing network access. Ofgem would review the level of the incentive as part of the next price control review in 2010. This incentive would only apply in circumstances where the generator and DNO have agreed on a standard connection. Given that Ofgem has adopted a £50/kW incentive rate (rather than around £40/kW as could have been used based on DNOs' information) it does not intend to provide DNOs with additional revenue to cover costs that they may incur in this respect. DNOs and generators would be free to agree variations in these terms as part of the bilateral connection agreement. **Ofgem welcomes views on the practical application of this incentive.**

Modelling the incentive scheme

5.40. The figures that are set out in Table 5.1 have been calculated using an annuity approach. An alternative would be to base the incentive scheme on a more traditional RAV approach (where 100 per cent of the costs are included in the RAV but at a lower rate of return than the allowed cost of capital in order to achieve equivalence with the annuity approach). Regardless of the approach taken the amount of revenue recoverable is the same in present value terms (and the rate of return is almost the same) – although the RAV approach would provide a higher level of revenue recovery in the initial years of the assumed asset life and lower levels in later years. The annuity approach has the advantage of providing a more stable revenue stream which should allow GDUoS charges to have more stability over time and at this stage Ofgem's intention is to use this approach. However, this will be reviewed in the light of the results from the financial modelling of the overall price control.

Definitions and reporting

5.41. It is important that clear definitions are provided to DNOs for the purpose of reporting performance under the incentive scheme to ensure that Ofgem can monitor and enforce compliance with the mechanics of the scheme. Ofgem needs to consider the most appropriate reporting framework for distributed generation. To ensure that the scheme can be monitored and enforced, and that robust information is provided by DNOs, it may be necessary to put in place a specific reporting framework – similar to that which has been used for quality of service – including providing reporting definitions and guidance notes. Ofgem expects, as a starting point, to base any definitions on those used in the DG-BPQ. **Views are invited on reporting (including any audit) arrangements.**

Registered Power Zones and Innovation Funding

5.42. The October update document and the December document set out Ofgem's further thinking with regard to the IFI and RPZs and indicated that work was being undertaken to develop a Regulatory Impact Assessment (RIA) to better understand the costs and benefits of introducing these incentives. The RIA is available in a separate document.[24] **Ofgem considers that the RIA gives confidence to proceed with the introduction of these new incentive mechanisms** and the rest of this section sets out how they will work including issues that still need to be considered.

Views of respondents

Innovation Funding Incentive (IFI)

5.43. Most respondents that expressed a view about the IFI were supportive of it. The key parameters of the IFI proposal are the R&D Intensity and the level of pass through. Support was expressed for the proposed R&D Intensity (0.5% of Turnover) and no alternative levels were proposed. Regarding the pass-through rate, the majority of parties that commented on this argued that the pass-through rate should be higher than that proposed by Ofgem. However, a number of respondents supported the Ofgem proposal.

5.44. The simplifications to the incentive proposed in December were broadly supported.

Registered Power Zones (RPZ)

5.45. There continues to be wide support for the concept of the RPZ with a substantial majority of the comments received offering support. However, there is a wider range of views about their implementation. Views are quite evenly divided about both the simplified proposals and the use of an advisory panel that Ofgem proposed in December. There is also concern regarding the application of industry standards and the treatment of schemes that are not wholly successful.

5.46. Ofgem restates its views on these subjects here but recognises that further work and discussion with affected parties is required to ensure effective implementation of the RPZ incentive.

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[24] "Regulatory Impact Assessment for Registered Power Zones and the Innovation Funding Incentive", Ofgem, March 2004

Ofgem's proposals – Innovation Funding Incentive

5.47. As discussed above, there is support for the proposed upper limit of IFI funding at 0.5% of turnover (the R&D Intensity) and the analysis in the RIA indicates that the funding resulting from this proposal is proportionate to the benefits that are expected to be delivered. **Ofgem proposes that the R&D Intensity cap for IFI is 0.5% and that IFI funding will be on a use it or lose it basis.** A company will be allowed to carry forward from one year to the next year up to 50% of the maximum allowable IFI funding for a given year. However, cumulative carry forward will not be allowable and the pass-through rate will be determined by the year in which the expenditure occurs.

5.48. Ofgem is not convinced that a higher pass-through rate can be justified. It is important that DNOs should be exposed to some of the financial risk of R&D to encourage efficient expenditure. **Ofgem proposes to maintain the profile of pass-through set out in the December document (which averages 80% over the price control period).** Thus, on average over the next period, DNOs will contribute at least 20% funding to R&D activities with consumers meeting the balance. The tapered pass-through has the further advantage of providing a greater incentive for first-movers. The pass-through profile is shown in Table 5.2.

Table 5.2: Pass-through of the IFI

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

5.49. The December consultation raised the issue of internal DNO costs for IFI project activities. It is not the intention of the IFI to encourage DNOs to re-establish in-house R&D facilities. However, Ofgem recognises that to pursue IFI projects successfully the DNOs do need to invest a certain level of their own resources. **Ofgem proposes that the IFI funding can be used to fund internal company expenditure but should be capped at 15% of the total IFI funding in each year.**

5.50. It will be necessary to specify clear criteria that describe an eligible IFI project. These will be developed to be consistent with the following aim. **IFI projects will be focused on the technical development of distribution networks (up to 132kV) to deliver value (i.e. – financial, supply quality, environmental, safety) to end consumers.** IFI projects might be expected to embrace all aspects of distribution system asset management from design through to construction, commissioning, operation, maintenance and decommissioning.

5.51. **Ofgem also proposes that any company that wishes to pursue IFI funded projects will have to produce and comply with a good practice guide for managing R&D projects.** In the interests of efficiency and transparency, Ofgem would wish to see the DNOs co-operating to produce a common good practice guide. This approach is consistent with our view that R&D collaboration between two or more companies is likely to be of benefit to consumers. The Technical Steering Group[25] (TSG) has a commitment to prepare a similar document for introducing innovation on networks (RPZ) and Ofgem suggests that, with the agreement of the Distributed Generation Co-ordinating Group (DGCG), this work might usefully be combined. On behalf of consumers, Ofgem will endorse the good practice guide that each company adopts and we wish to see it as a published document that is under open governance.

5.52. **Ofgem proposes that there should be open reporting of IFI activities as set out in the December document.** We would expect that the good practice guide would contain a model form for the annual reporting of IFI activities which will provide details of project plans and achievements. In particular, we believe that the potential benefit to consumers should be quantified to justify an IFI project and that this benefit will be detailed in the model form annual report.

5.53. Ofgem wishes to encourage momentum to be maintained and **would welcome views on putting in place interim arrangements to enable IFI projects to commence ahead of the start of the next price control period** if a company wished to do so. Commencement from Autumn 2004 might be practical,

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[25] The TSG reports to the Distributed Generation Co-ordinating Group (DGCG) which is jointly chaired by Ofgem and the DTI

provided the good practice guidance document referenced above has been developed and adopted.

Ofgem's proposals – Registered Power Zones

5.54. Ofgem proposes that DG connection projects may be registered as RPZs at any time during the next price control period. Such projects will attract a 100% uplift of the £/kW element of the DG incentive scheme (Table 5.1) for a five year period commencing on the date of commissioning of the project. This will raise the average rate of return for RPZ projects, calculated on the same basis as for other DG connections, to about 10%.

5.55. It is further proposed that the additional revenue (i.e. – the revenue derived from the uplift of the £/kW element described above) that a DNO can claim for RPZ projects will be capped at £0.5 million per DNO per year. Consideration will need to be given to the appropriateness of providing a carry-forward mechanism for RPZ funding.

5.56. It is proposed that the cost of RPZ projects will be met by generators as a class within a DNO area in the same way as the DG incentive scheme. It would seem appropriate for the Structure of Charges Implementation Steering Group to consider how this should be done and make recommendations.

5.57. Ofgem's further proposals for RPZs are summarised in the panel below. Particular issues are dealt with in the text that follows.

	Registered Power Zones **Proposals**
a)	Targeted at new DG connection schemes where innovation is an integral part of the project and can be demonstrated to offer material consumer advantage compared with a conventional solution.
b)	Ofgem will develop and publish registration guidelines for DNOs. These will in particular define RPZ innovation and will be developed by Ofgem to provide clear guidance to DNOs and generators.
c)	The generator(s) directly involved in the innovation will have to support the RPZ proposal.
d)	Ofgem will register, though not approve, RPZ projects and, when appropriate, will seek advice from an independent panel, established by Ofgem, to confirm the innovation content and potential benefits of an RPZ proposal.
e)	The DNO would take full responsibility for the management of the risks of the scheme and would offer the connecting generator commercial terms reflecting these risks.
f)	Where the quality of supply of consumers might be affected by the innovation the DNO will put

in place contingency measures to manage this risk, and measurement equipment to confirm Quality of Supply performance. This would remain in place while any enhanced risk remained.

g) Open reporting of RPZ projects would be required annually; this is intended to stimulate good management and promote sharing of innovation good practice. A model form report will be established as part of the good practice guide.

h) Technical performance monitoring information will be made available on request to bona fide parties and referenced in the annual report.

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

j) A good practice guide for managing network innovation will be applicable and is a pre-condition for registration of RPZ projects. This might usefully be integrated with the guide required under IFI.

k) The RPZ incentive will be reviewed in 2007 together with the IFI.

Additional RPZ issues

5.58. A number of respondents have questioned the appropriateness of requiring all industry codes, standards and engineering recommendations to be complied with in an RPZ. Ofgem has a process for considering derogations and it is proposed that where an RPZ requires a derogation this should be dealt with as part of the registration process. Any derogation will not apply to any quality of supply targets or obligations.

5.59. There is a risk that follows as a consequence of the innovation content that an RPZ project will not meet its design objectives in full or in part. Ofgem is of the view that this risk should be covered by the potential for earning a higher rate of return.

Views invited

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

- the proposed higher incentive rate for SSE-Hydro based on higher costs;
- application of the DG incentive to microgeneration;
- reporting arrangements for the DG incentive scheme;
- **IFI –** the criteria that should define an IFI project;
- **IFI –** the practicality and benefit of putting in place interim arrangements for IFI before 1 April 2005;

- **RPZ –** the defining criteria for RPZs;
- **RPZ –** on the practicality of the proposals and the potential barriers that might constrain useful RPZ activity; and
- **RPZ & IFI –** the proposals for an industry-wide good practice guide.

6. Assessing costs

6.1. This Chapter provides an update on Ofgem's work assessing DNOs' costs and in particular:

- ♦ an outline of the information that DNOs have submitted in relation to their future costs in the forecast business plan questionnaire (FBPQ);
- ♦ the work that is been undertaken to adjust (or normalise) DNOs' costs for accounting and other differences.

6.2. Ofgem's approach to the assessment of the DNOs' efficiency i.e. top down analysis and bottom up modelling was discussed in the December document. Ofgem's approach in these areas remains largely unchanged and therefore there is little detail on these areas in this document. A number of key issues remain to be decided in these areas and they will be discussed together with initial analysis in the June Initial Proposals document.

Review of forecasts

6.3. The December document discussed the forecast business plan questionnaires (FBPQs) which were being completed by the DNOs. The DNOs have provided forecast numbers up to 2010 (with a summary of indicative numbers up to 2020). The key elements of the FBPQ are:

- ♦ **base case –** DNOs were asked for the minimum costs necessary to maintain current underlying performance and network resilience over the period to 2010 assuming that there is no change from present operating, technical and regulatory conditions;
- ♦ **quality of supply scenario –** Ofgem set out an improvement scenario for CIs and CMLs for each DNO based on comparative analysis across DNOs using disaggregated circuit performance data, as described in paragraphs 4.11 to 4.24 of the October 2003 price control update document. The scenario asked for the minimum costs needed to achieve 40 per cent of the projected 2020 benchmark by 2010; and

- **DNO’s own scenario** – based on the DNO’s own preferred assumptions over the next price control period.

6.4. The DNOs have provided high level summaries of these forecasts which are included in Appendix 5 and more detailed summaries which are set out in the separate Summary of DNO Forecasts Appendix published alongside this document.

Overview of the DNOs’ forecast operating costs

6.5. Generally, DNOs are forecasting base case controllable operating costs, excluding pension costs and lane rentals that remain broadly flat in real terms, some being slightly higher and some slightly lower than 2002/03 levels. Some DNOs have included in their forecasts some uncertain items like lane rentals (on the basis that current trials in other DNO areas will be applied to them) and Electricity Supply Quality and Continuity Regulations (ESQCR) related work. Other DNOs have not included these costs in their forecasts but say in their commentary that although these costs are uncertain they are likely to arise in the next price control period.

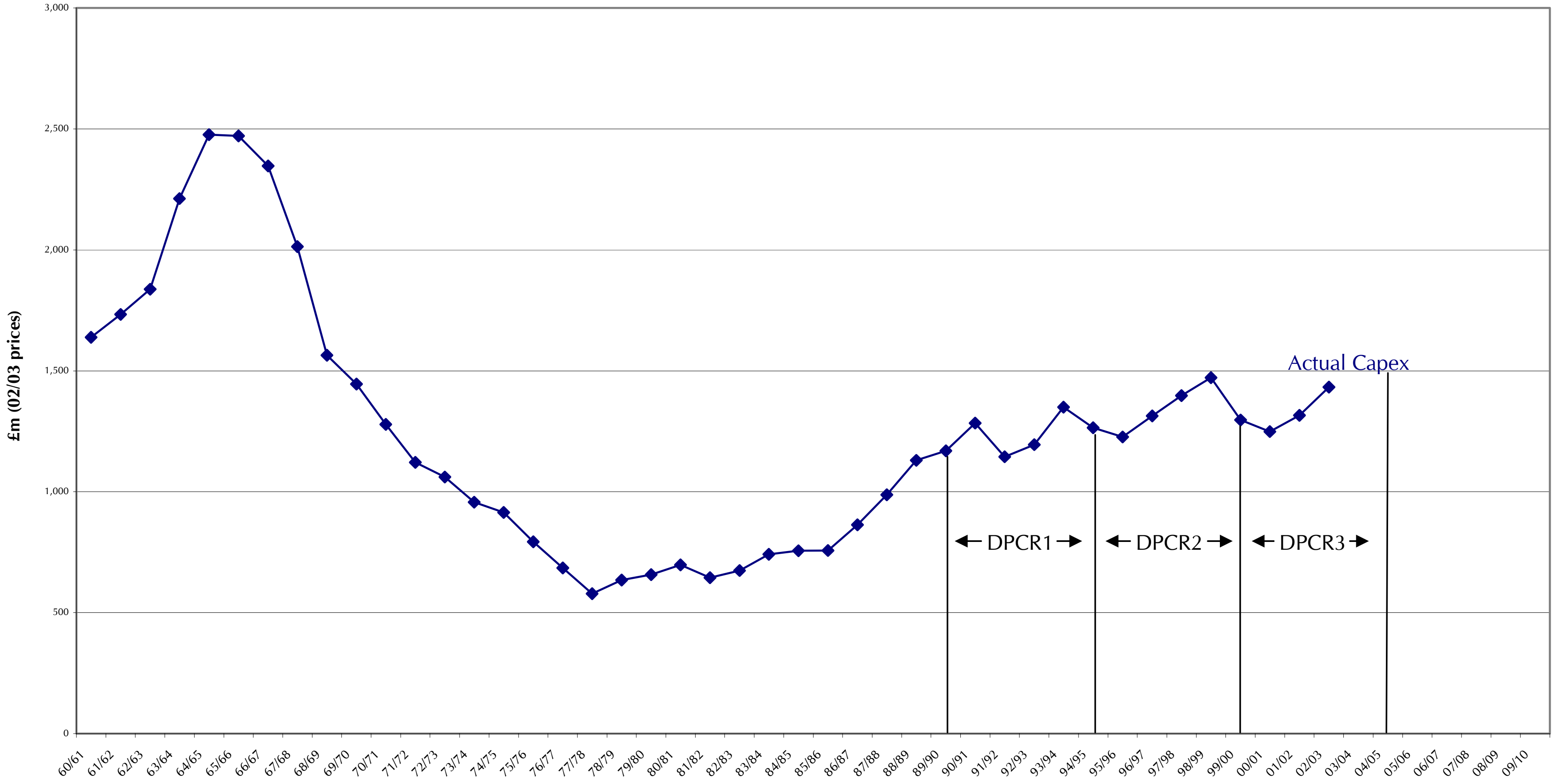
6.6. Some companies are suggesting that future efficiencies could range between 1 to 2 per cent per annum, whilst others are suggesting that no further efficiencies can be made from their present position. The companies also suggest that there are upward pressures on their costs, in particular relating to vegetation management and labour skills shortages, which will offset cost reductions due to efficiencies and in some cases result in increased costs.

6.7. The quality of supply and the DNOs’ own cases generally have only a small (or zero) impact on operating costs.

Overview of DNOs’ forecast capital expenditure

6.8. The figures below illustrate the historical trend of outturn capex, the DNOs’ forecasts and Ofgem’s final proposals at previous price controls. Figure 6.1 shows the outturn trend from 1960.

Figure 6.1 Actual DNO Gross Capital Expenditure (1960 to 2010)



6.9. For the base case, most DNOs are forecasting increased asset replacement activity over DPCR3 and suggest this is the consequence of an ageing network. For about half of the DNOs, this results in an increase in capex of up to 20% over DPCR3 levels. Five DNOs are forecasting an increase in capex in the range 40% – 95% over DPCR3 levels.

6.10. Companies have included around £200m for spend due to compliance with ESQCR, with three companies accounting for about £120m of the total spend. The amounts the DNOs are forecasting for this issue vary widely and some companies are forecasting up to £70m. The effect of ESQCR is hard to quantify at the moment and Ofgem is working with the DNOs to identify the likely impact.

6.11. For the quality of supply scenario, the DNOs are forecasting a total incremental spend of around £700m in addition to the base case. Two DNOs, (SP Manweb and EDF - LPN), are already achieving their performance targets and so do not forecast extra capex for this scenario. Most DNOs forecast that they can achieve the 2010 and the 2020 targets using conventional techniques of overhead line refurbishment and automation. EDF - EPN, EDF - SPN and SSE - Southern are forecasting required spend between £140 – 150m above the base case. EPN and SPN suggest that conventional techniques alone will achieve the 2010 targets but not the 2020 targets. Furthermore they suggest that to reach the 2020 targets they need to take a different approach and have assumed radical network reconfiguration. SSE - Southern has assumed it will need to carry out an extensive overhead line rebuild and under-grounding programme.

6.12. The DNOs' own scenarios show a total incremental spend of around £800m over the base case. All companies are showing increases compared to the base case but some vary considerably from the quality of supply scenario. The three companies with high spend in the quality of supply scenario forecast around £100m less in their own cases. EDF - EPN and EDF - SPN assume they can meet the 2010 targets, but as they claim they cannot meet the 2020 targets without significantly more spend and/or a different approach, they have not included these costs in their own case. SSE - Southern assume they can get to the 2010 target without taking on the more expensive techniques. CN - Midlands assumes additional spend of around £90m over the quality of supply scenario to improve its network resilience and environmental impact. The other DNOs forecast up to £40m above the quality of supply scenario for a variety of reasons including additional refurbishment, automation, advance replacement schemes and, in some cases, infrastructure to facilitate the connection of distributed generation.

Normalisation of costs

6.13. The objective of the normalisation work is to put the DNOs' cost data on a comparable basis for the top down and bottom up efficiency analysis. A significant amount of work has already been undertaken on normalisation and has focused on 2002/03 data. This has involved a number of meetings with companies, including visits to each DNO group. Companies have had an opportunity to comment on the detail of the work as it has been undertaken and they recently provided Ofgem with their comments on Ofgem's initial view of the adjustments.

6.14. Table 6.1 sets out the various adjustments that have been made to controllable operating costs and starts from the numbers disclosed in the December document as being DPCR4 controllable costs. These numbers will form the basis of Ofgem's view of normalised costs. Work is still being undertaken to improve the consistency of data and there are still probably significant adjustments to be made so the numbers should not be used to compare companies against each other. The main issues for resolution are:

- the boundaries between different categories of expenditure;
- capitalisation policies;
- overhead allocation; and
- the effects of outsourcing.

Table 6.1 Normalisation adjustments made to the DNOs' 2002/03 operating costs

DNO	December Consultation Document Recurring controllable costs	Subsequent adjustments to Atypical/One-off items	Revised Recurring Controllable costs	Normalisation adjustments: Metering	Pensions	Non-operational depreciation and Transport Fleet	Insurance costs	Corporate costs	Other adjustments	132kV cost adj - Scotland	Preliminary Normalised Controllable costs
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
Aquila	42.0	0.7	42.7	(5.1)	(1.2)	(2.1)	-	-	(0.8)	-	33.5
EME	28.7	1.9	30.6	(6.8)	(0.4)	0.4	(1.5)	(0.1)	2.2	-	24.4
UU	39.2	(7.1)	32.1	(1.2)	5.4	(1.4)	-	(0.7)	(0.9)	-	33.3
NEDL	34.2	(3.0)	31.2	(2.8)	(0.9)	(0.1)	(0.8)	(0.1)	1.1	-	27.6
YEDL	44.1	(3.5)	40.6	(6.0)	(0.9)	(3.1)	(1.4)	(0.1)	1.9	-	31.0
WPD - SWest	28.1	2.3	30.4	(4.6)	(1.0)	0.3	-	(0.1)	(1.2)	-	23.8
WPD - SWales	24.0	3.3	27.3	(3.3)	(1.4)	-	-	(0.1)	(0.1)	-	22.4
EDF - London	35.6	1.3	36.9	(3.6)	(1.1)	(0.2)	-	(0.1)	(6.4)	-	25.5
EDF - Seeboard	52.9	0.0	52.9	(7.9)	(1.6)	(1.4)	(1.7)	(0.1)	(0.4)	-	39.8
EDF - Eastern	51.3	0.0	51.3	(8.5)	(1.6)	(0.4)	(2.6)	(0.2)	(1.5)	-	36.5
SP Distribution	25.8	1.1	26.9	(4.5)	(1.7)	(1.5)	-	(1.8)	(2.1)	3.0	18.3
SP Manweb	28.5	1.1	29.6	(6.2)	(1.6)	(1.6)	-	(1.6)	(2.3)	-	16.3
SSE - Hydro	33.1	(1.0)	32.1	(2.4)	(1.7)	(0.7)	(1.3)	-	-	2.3	28.3
SSE - Southern	45.6	(1.0)	44.6	(5.2)	(3.0)	(1.1)	(1.5)	-	(0.7)	-	33.1
Total	**513.1**	**(3.9)**	**509.2**	**(68.1)**	**(12.7)**	**(12.9)**	**(10.8)**	**(5.0)**	**(11.2)**	**5.3**	**393.8**

6.15. Normalisation of the costs starts by adjusting them for atypical and one-off costs to obtain recurring controllable costs. Atypical and one-off costs or credits are associated with abnormal activity levels or rare or unique events. Therefore for the purposes of comparative assessment it is necessary to remove such items from the DNO's controllable costs. However for the purposes of setting the DNOs' revenue allowances an underlying level of atypical and one-off costs or credits may need to be included in the revenue allowances.

6.16. Table 6.2 describes the other normalisation adjustments made to the recurring controllable costs.

Table 6.2 Other normalisation adjustments

Metering	Metering operating costs have been removed as they will be included in the separate metering price control.
Pensions	Pension costs have been excluded for the time being.
Non operational depreciation and Transport	Non operational depreciation charged indirectly or directly to DNOs has been excluded. An adjustment has been made to ensure that a consistent level of transport costs are included in the DNOs' costs regardless of whether such operations have been outsourced or remain in house.
Insurance	Insurance premiums relating to exceptional storm events have been removed as there are differing approaches adopted across DNOs (e.g. some self-insure).
Corporate costs	Corporate costs (e.g. marketing etc) that are not relevant to the operation of a DNO have been removed, whether allocated from the parent or via a recharge from a Related Party.
Other Adjustments	Costs relating to charges such as lane rentals, congestion charges, etc, have been excluded as these are usually specific to a particular region. In addition, adjustments have been made to address inconsistencies in capitalisation policies. Profit margins charged directly or indirectly to the DNOs by Related Parties have been excluded.
Scottish 132kv costs	These costs have been added to the costs of Scottish Hydro and Scottish Power to provide consistency with the other DNOs.

6.17. The preliminary view of normalisation set out in Table 6.1 shows significant differences and a number of areas for further analysis. It seems likely that there are still significant accounting differences (for example in the low operating cost levels shown for the ScottishPower companies). In addition, consideration may be given to regional factors where these impose material additional costs on some DNOs. Any adjustments for regional factors will be set out in the June initial proposals document. It is important to note that some of the normalisation adjustments made to operating costs equally apply to other types of expenditure incurred by DNOs. Therefore there will be an interaction between this normalisation process, Ofgem's assessment of faults and capital expenditure and the roll forward of the regulatory asset value.

Bottom Up modelling

6.18. The December document discussed the bottom up models Ofgem is developing with advice from PB Power (PBP). Constructing these models requires analysis of work and activity levels and the associated unit costs in order to generate a projection of efficient costs which can be compared to the DNOs forecasts. Ofgem's and PBP's approach remains broadly unchanged from the December document. Initial analysis based on PBP's models will be published in the June Initial Proposals document.

Top down analysis

6.19. The December document set out the key principles guiding the use of benchmarking to assess the relative efficiency of the DNOs and how the techniques of regression and data envelopment analysis (DEA) can be applied. The December document also discussed a number of specific benchmarking issues and mentioned the study by Cambridge Economics on expected productivity growth in the DNOs. Ofgem's broad approach to top-down analysis remains as set out in the December document – although detailed issues about how the analysis is undertaken will need to be considered in the coming months. The results from Ofgem's top down analysis will be published in the June initial proposals document.

Mergers

6.20. In the December document Ofgem discussed the impact of mergers between DNOs on the benchmarking analysis. Ofgem said that it would analyse the eight company groups as well as the 14 DNOs. The document also discussed the treatment of mergers which took place before June 2002 and said there were two possible options that Ofgem is considering in terms of revenue reductions:

- deduct £12.5m (1997/98 prices) per year, having allowed the DNOs to retain the benefits of merger savings for five years, with this reduction to be equally split between the DNOs concerned; or
- deduct a total of £32m (2001/02 prices) over five years i.e. £6.4m per year to be shared between the DNOs concerned.

Views of respondents

6.21. One DNO commented that Ofgem's work on DNO mergers had demonstrated that DNO mergers released savings not available to other transactions. The same DNO thought it should be straightforward to use the figure of £12.5m as the basis of a normalisation adjustment for mergers when assessing all 14 DNOs. Another DNO said a true value of mergers was required to ensure that DNOs would not be treated in an unbalanced way.

6.22. On the issue of revenue reductions one DNO believed that as merger savings were already in the DNO cost bases and would be picked up by the regression analysis a separate revenue adjustment would therefore double count such savings. Another DNO said that merger savings should not be treated differently from any other efficiency saving. One DNO said the figure of £12.5m per year was consistent with its experience on merger savings. One DNO said that it would not be appropriate to apply the reduction of £32m to mergers before June 2002 as the mergers concerned had proceeded on the expectation of a revenue reduction of £12.5m per year. A number of DNOs emphasised that DNOs should be allowed to retain the benefits of merger savings for five years. A number of DNOs queried the logic in expecting all merged DNOs to be on the efficiency frontier.

Ofgem's further thoughts

6.23. The evidence from mergers within the British DNOs clearly demonstrates that merged DNOs are able to reduce certain costs - in particular fixed costs, such as head office and corporate functions and sharing of best practice. However, many of these savings are also achievable through other corporate structures and are not exclusive to mergers between DNOs. This suggests that it is not necessary to adjust DNOs' costs for merger savings for the purposes of benchmarking.

6.24. Ofgem notes the responses summarised above and will set out further thinking on the treatment of merged DNOs in the June Initial Proposals document.

RAV Roll forward

6.25. Ofgem is reviewing the submissions from the DNOs and also the evidence provided by PKF (Ofgem's DPCR3 consultants) and expects to be in a position to say more about this issue in the June Initial Proposals document. In addition to the treatment of fault costs described in the December 2003 document, Ofgem is reviewing adjustments needed to remove inter-company margins and the effects of changes to accounting policies since 1997/98.

Views invited

6.26. Views are invited on any issues raised in this chapter in particular on:

- DNOs' forecast costs (base case, quality of supply scenario and the DNOs' own scenarios); and
- the normalisation adjustments.

7. Financial issues

Introduction

7.1. This Chapter sets out Ofgem's further thoughts on financial issues and in particular on:

- the financial ringfence;
- the cost of capital, including an initial range for use from 1 April 2005; and
- the treatment of pension costs.

Financial ring-fence

7.2. The December 2003 document proposed not to substantially strengthen the existing financial ring-fence. The proposed introduction of a Special Administration regime as part of the Energy Bill should help address concerns in relation to security of supply in the situation where companies become insolvent. However, it would not address the situation where the parent company gets into financial distress, which may result in increased pressure on the licensed entity.

7.3. Ofgem invited views on its proposal to clarify the existing arrangements by codifying a 'cash lock up' in all DNO licences.

Views of respondents

7.4. Two respondents supported the introduction of a cash lock-up mechanism, with one stating that the trigger should be set to take effect once the licensee's issuer credit rating has fallen to the minimum rating consistent with investment grade.

7.5. Five DNOs considered that there was no need to strengthen the current financial ring-fence. One of these stated that cash lock-up was a heavy handed device and another noted that it would only resolve financial problems upstream as against addressing problems at the licensee level. This same respondent noted that other options such as interim determinations to deal with unforeseen cost shocks should be explored first.

7.6. Two respondents considered that the trigger for any cash lock-up should be set at BBB-, while one considered that any lock-up which operated before a company's credit rating had fallen below BBB- would imply raising the minimum credit rating required by a licensee. One further respondent stated that a cash lock-up should only be invoked when insolvency is imminent, i.e. downgrade below B- into any C grade rating.

Ofgem's proposal

7.7. Ofgem remains of the view that there is no need for a substantial strengthening of the existing financial ring-fence arrangements. An important consideration in Ofgem's thinking has been the proposed introduction of a Special Administration regime as part of the Energy Bill.

7.8. However, Ofgem does consider it important to clarify how the existing financial ring-fence arrangements would be enforced. For this purpose, Ofgem proposes to seek a collective modification of SLC47 of electricity distribution licences (and, in due course, the equivalent conditions of electricity transmission and gas transporter licences), to require that, in certain circumstances, prior consent of the Authority be obtained for any transaction of a type referred to or described in SLC47(1)(b)(i)-(vii).

7.9. SLC47(1)(b) prohibits the licensee, without the prior written consent of the Authority, from transferring, leasing, licensing or lending any sum or sums, asset, right or benefit to any affiliate or related undertaking otherwise than by way of certain types of transaction, and subject to certain conditions, set out in sub-paragraphs (i) to (vii) inclusive. These transactions include payment of dividends and other distributions, certain transfers of money or other valuable assets on deferred payment or repayment terms, payments of principal and interest on certain loans, fair value payments for goods, services and tax losses, and acquisitions of certain investments.

7.10. Ofgem is proposing to continue to allow such transactions to be made without the need for prior written approval of the Authority unless, at the relevant time, either

- the licensee does not hold an investment grade issuer credit rating; or
- the licensee's issuer credit rating is at the minimum investment grade level and:

  a) is under review for possible downgrade; or

  b) is on credit watch with negative implications; or where neither a) nor b) applies,

  c) carries a negative rating outlook

At present, minimum investment grade means a rating of BBB- (S&P) or Baa3 (Moody's).

7.11. In any of these circumstances, prior written approval would be required for any such transaction.

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

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

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

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

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

The cost of capital

7.17. In running its business, a company will incur financing costs in the same way as it incurs operating and capital costs. Regulators have tended to make an allowance for the efficient financing costs that a company will incur by estimating a return on the value of capital employed in the business (the regulatory asset value, or RAV) equal to the expected return required by providers of finance – both debt and equity (the cost of capital). The cost of capital makes up a significant proportion of the overall costs that a company needs to meet in order to be able to operate effectively and invest in its networks.[26] The Weighted Average Cost of Capital (WACC) is the weighted average of the *expected* cost of equity and the *expected* cost of debt.

7.18. Ofgem has proposed to use a post-tax approach to the cost of capital. This means that the price control calculations will allow specific estimates of tax costs plus a return on a pre-tax dent, post-tax cost of equity basis – termed the 'vanilla' WACC (i.e. without any tax adjustment to the cost of equity or cost of debt).

7.19. Ofgem's initial estimate for the range for the cost of capital is set out in Table 7.1. The allowed cost of capital for the existing price control (on a pre-tax basis) is 6.5 per cent. The equivalent range in Table 7.1 for comparison is 6 to 7.2 per cent. The proposed ranges for the cost of capital reflect the strong investment focus of this review. It is expected that in order to finance this investment companies might have to access the debt and/or equity markets. This has been a determining factor in proposing the initial ranges for the cost of capital. Further details on Ofgem's work on the cost of capital are set out in a separate Appendix.[27]

[26] The July 2003 document showed that for 2001/02 financing and tax costs accounted for 26 per cent of price control revenue – using an assumed cost of capital of 6.5 per cent consistent with the existing price control.
[27] Background information on the cost of capital, Ofgem, 24 March 2004.

Table 7.1: Summary table of cost of capital inputs and the initial ranges

		OFGEM 1999		OFGEM 2004	
		LOW	HIGH	LOW	HIGH
A	risk-free rate	2.25	2.75	2.25	3
B	debt premium	1.85	1.7	1	1.8
C	pre-tax cost of debt = A+B	4.10	4.45	3.25	4.80
D	post-tax cost of debt = C x (1-K)	2.87	3.12	2.28	3.36
E	Gearing	0.5	0.5	0.5	0.6
F	Equity Risk Premium	3.25	3.75	2.5	4.5
G	equity beta	1	1	0.6	1
H	pre-tax cost of equity = J / (1-K)	7.86	9.29	5.36	10.71
J	post-tax cost of equity = A + (F x G)	5.50	6.50	3.75	7.50
K	Corporation tax rate	0.30	0.30	0.30	0.30
L	pre-tax CoK = (C x E) + (H x [1-E])	5.98	6.87	4.3	7.2
M	post-tax CoK = (D x E) + (J x [1-E])	4.19	4.81	3.0	5.0
N	'Vanilla' WACC = (C x E) + (J x [1-E])	4.80	5.48	3.5	5.9
	Proposed Range Vanilla WACC			**5.1**	**5.9**
	Equivalent Range pre-tax			6.0	7.2
	Equivalent Range post-tax			4.2	5.0

Financial modelling

7.20. To improve the transparency of the price control review Ofgem published a draft financial model in November 2003 for comment. Ofgem has received a number of responses to that draft and is also holding a series of workshops with the DNO's to discuss their responses in detail.

7.21. Ofgem intend to publish a revised draft of the financial model in April 2004 which will take account of the updates to the model and developments in the proposed approach to setting the price controls.

7.22. Ofgem's further thoughts on the use of financial indicators will be published in the June initial proposals document.

Treatment of pension costs

7.23. The December paper set out an update on the treatment of pension costs and in particular included a methodology statement. This section sets out Ofgem's further thoughts. The comments in this section refer to the broad framework for the treatment of pension costs and therefore also apply to NGT and the Scottish transmission businesses.

Views of respondents

General

7.24. Several respondents stated that they did not think a logging up mechanism would be appropriate. They felt it would be no clearer nor any less complex than allowing costs to be passed through and suggested that contribution rates only change after a valuation. One respondent commented that adjustments should only be made for a pension scheme valuation within the price control period if the variation in contribution rates exceeded a predefined amount. Another respondent pointed out some difficulties with logging up (e.g. cash flow concerns as the amounts can be large, and uncertainty as to the extent that costs would actually be recoverable at subsequent reviews).

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

7.25. While most companies agreed with the principle of splitting the price-controlled from the non-price-controlled elements, they pointed out the practical difficulties, particularly with historical data, and suggested that a degree of estimation or some other pragmatic approach would be required. Generally there were no adverse comments over Ofgem's suggested approach of allocating the liability of active members based on present employment and the liability of deferreds and pensioners on the basis of last employment. One DNO said that for post-privatisation leavers, given the inconsistencies in the data, it would be best to use a pragmatic approach rather than last employment.

7.26. The December paper identified two methods for allocating assets to liabilities. Three respondents thought it would be appropriate to match scheme assets to different categories of scheme members, reflecting the different maturities of these categories. Two did not think it would be appropriate because of practical difficulties in applying this method; they preferred allocating assets in proportion to liabilities.

Over or under provision

7.27. Respondents generally said that it was unclear what allowances were made for pension costs in the last price control review. One respondent also said that it was unclear what allowance was made for pensions in capital costs at the last review and that a significant proportion of pension costs are attributable to capital costs.

7.28. One company argued that the uncertainty as to what was allowed would mean they would be unable to agree to any calculation of over- or under-funding. Three companies argued that for DPCR 3 it would be most appropriate to assume allowances were based on the frontier company or an average of the frontier companies. One company argued that the most pragmatic and equitable approach would be to assume the allowance was the amount actually paid.

7.29. One respondent said that since it was unclear what was allowed in the last price review, it would be unfair to penalise companies that have paid amounts determined by independent actuaries. It was also mentioned by a respondent that Ofgem should take account of any over-funding in the last two years of DPCR 3.

7.30. One company said they could not see why it was appropriate to adjust over/under contributions by a benchmark return (WM Mercer published return) rather than by the actual returns earned, when Ofgem claimed not to want to second guess the investment strategy of the schemes.

Early retirement deficiency costs (ERDCs)

7.31. In response to a question from Ofgem in the December document, some Network Work Operators (NWOs) have provided Ofgem with documentation intended to demonstrate a basis of expectation that early retirement deficiency costs could be subsequently recovered from consumers as part of future price controls.

Stewardship

7.32. Respondents generally agreed that while some overall test on stewardship was appropriate, they did not believe that anything untoward would be found. Some pointed out that there was already oversight of pension schemes from trustees, actuaries and pension scheme regulators.

7.33. One company said that Ofgem should not introduce a test that it could not measure objectively and that Ofgem should explain what constituted acceptable stewardship.

7.34. One respondent argued that care was needed in adjusting for the level of returns, to ensure that hindsight was not applied to behaviour that was legitimate in the circumstances of the time a decision was taken.

Ofgem's proposals

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

7.35. Ofgem remains of the view that the price controls should only provide for recovery of pension costs relating to the business that will be subject to the price control. In practice, for the post-privatisation period, this allocation can be achieved by assigning liabilities based on the current employment of active members (i.e. of current employees) and the last employment of post-privatisation leavers. For pension scheme members that left employment prior to privatisation - where data is available - liabilities will be allocated according to last employment. Where data is not available, liabilities associated with pre-privatisation leavers will be split based on employment costs in the year of privatisation.

7.36. Having allocated the liabilities, there are then two options for allocation of assets: in proportion to liabilities or matching as far as possible the type of assets held to the maturity profiles of the various categories of liability. Ofgem is still considering this issue and expects to clarify its approach in the June paper.

Over or under provision

7.37. In principle, Ofgem considers that companies that have responded to the occurrence of a pension deficit by increasing contributions should not be worse off than those that have not increased contributions. This would be achieved by making adjustments for over or under contribution to the pension scheme relative to the amounts companies were allowed to recover under price controls.

7.38. However, there have not been explicit allowances for pension costs at previous controls (except for the Transco review in 2001). It is therefore difficult to assess what allowances were made in previous price controls.

7.39. For the distribution businesses, Ofgem considers that the available evidence suggests that companies have probably contributed substantially less than was envisaged in setting the price controls over the period since 1995. This appears less likely to be the case in 2003/04 and 20004/05. The amounts involved may well exceed £100m across the industry - however, the lack of explicit allowances makes precise quantification difficult.

7.40. In considering these issues and the responses to the December paper (which were generally opposed to any adjustment), Ofgem is conscious of the desirability of achieving an appropriate balance in the overall treatment of pension deficits. Subject to the treatment of ERDCs set out below, Ofgem is minded not to make adjustments for over or under funding in relation to past price controls where the pension allowance was not separately identified.

7.41. Hence, for the DNOs, Ofgem does not propose to make an over/under funding adjustment for the period to 31 March 2005. For Transco, Ofgem does not intend to make such an adjustment for the period to 31 March 2002. For the electricity transmission companies, further consideration will be given to whether it is appropriate to make any adjustment for over-/under-funding in rolling forward the price controls, but it is Ofgem's intention not to make any adjustment prior to the originally scheduled end of the current controls.

7.42. However the application of the principle for all price control periods following those noted above will be unchanged. This implies that at each future price control review, Ofgem will review whether pension cost allowances have been too high or low and adjust the future allowance accordingly to make up the difference. Ofgem does not consider that it is necessary to make these adjustments on an annual basis.

ERDCs

7.43. Ofgem notes that NWOs have in the past reduced ongoing costs through early retirement programmes without making contributions to their pension schemes to offset the associated increase in liabilities (i.e. ERDCs). Ofgem does not contend that companies should have put funds into the scheme at that time – rather that companies faced a choice between putting funds into the scheme at that time and potentially having to put funds into the scheme at a later date if the scheme moved into deficit. Most companies rationally chose the latter approach. However, Ofgem's interpretation of this approach is that the option they took was to defer paying into the scheme the cost of the additional liabilities and make it contingent on the scheme remaining in deficit – not to avoid the cost entirely by passing it on to consumers. No companies have yet produced any evidence that there was any agreement that consumers would bear these costs if they subsequently materialised.

7.44. Therefore Ofgem is still minded not to allow any ex post pass through of these costs to consumers. Nevertheless, Ofgem will consider any new evidence or arguments that companies put forward, and will take a final view on this issue when we bring forward proposals for the price controls that will apply from April 2005.

7.45. In the context of the proposals for under-funding set out above, Ofgem considers that the approach proposed on the combination of issues represents, in overall terms, a proportionate approach to dealing with the costs of deficits that have arisen over the past few years.

Views invited

7.46. Views are invited in particular on the:

- financial ringfence;
- initial range for the cost of capital including the various parameters; and
- treatment of pension costs.

Appendix 1. Calculating the capex and opex rolling adjustments

This Appendix sets out how the incentive payment for the opex roller and capex rolling adjustment will be calculated.

The opex rolling adjustment

For 2003/04

The incentive payment under the opex roller for 2003/04 will be calculated as follows:

- The opex rolling adjustment only applies to **incremental** efficiency savings made in 2003/04;
- the incremental outperformance will be calculated in relation to the **highest previous outperformance** in DPCR3; and
- the results for 2004/05 will not be known at the time of the price control and hence are not taken into account. Opex efficiency savings made in the last year of DPCR3 will therefore be taken into account at the next review in the form of an adjustment to the incentive payment for DPCR5.

Table 1 Opex roller for DPCR3

	DPCR3				
	2000/01	**2001/02**	**2002/03**	**2003/04**	**2004/05**
Allowed opex	97	96	95	94	Taken into account in DPCR5 hence zero for DPCR4
Actual opex	94	88	84	79	
Total efficiency gain in each year	3	8	11	**15**	
Incremental efficiency gain	3 (not taken into account)	5 (not taken into account)	3 (not taken into account)	**4** (first incremental efficiency saving to which opex roller applies)	**4**
	DPCR4				
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Incentive payment	**4**	**4**	**4**	0	0

The opex roller only applies to opex efficiency savings made from 2003/04 onwards. The incentive payment for DPCR4 will therefore only be based on incremental efficiency savings made during 2003/04. Given that the total efficiency gain in the example is 11 in year 2002/3 and 15 in year 2003/04, the incremental outperformance is 15-11=4. As a result, the company will be given an incentive payment of 4 for the 2005/06 – 2007/08 period, which means that the company retains these incremental efficiency savings for a five year period.

Treatment of opex savings in 2004/05

In 2004/05 the normal operation of the price control review, without any opex roller, would result in opex underspend in 2004/05 being retained for up to six years.

Given the complexities of applying a rolling adjustment for this year, Ofgem does not intend to do so. This will result in incentives to reduce opex in 2004/05 being marginally stronger than otherwise.

However, there are other influences on efficiency (i.e. the current price review) and Ofgem does not consider that this difference is material.

The opex roller from 2005/06 to 2008/09

The incentive payment under the opex roller for 2005/6 to 2008/09 will be calculated in accordance with the following rules:

- the **DPCR4 opex roller period** comprises the first four years of DPCR4;
- at the start of year 1 of **DPCR4** the incentive mechanism will be reset to zero;
- the incentive payment is based on **incremental** opex efficiency savings in the opex roller period. The incremental outperformance in a given year will be calculated in relation to the **highest previous outperformance** in that opex roller period;
- in cases of opex overspend this will be offset against opex underspend in the five year opex roller period. This is to avoid incentives to load all overspend into any one year;
- the incentive payment is constrained not to be negative in any given year;

- the total incentive payment for opex savings made during 2005/6-2008/9 is constrained not to be greater than the average of the actual out-performance in year 3 and year 4 of DPCR4 (i.e. 2007/8 and 2008/9);
- exceptional (or atypical) items will not be excluded;
- there will be no multiplier;
- the incentive payment is calculated on a year by year basis every five years when the price control is reset;
- eligibility for the opex incentive payment may become subject to an eligibility test; and
- Ofgem will review the appropriateness of the opex rolling adjustment as part of the next price review.

Table 2 shows how the opex roller will work during DPCR4 and also illustrates the treatment of underperformance. The incentive payment will feed into the price control calculation and will be received during DPCR5.

Table 2 Opex roller for 2005/06 t0 2008/09

	DPCR4					DPCR5				
Year (£m)	2005/6	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Allowed opex	100	100	100	100	100	100	100	100	100	100
Actual opex	95	105	85	85	?	98	95	95	90	80
Out-performance	5	-5	15	15	?	2	5	5	10	20
Incremental Out-performance	5	-10	10	0	?	2	3	0	5	10
Incremental Out-performance 04/05	10	10	10	10	10					
Incremental Out-performance 05/06	5	5	5	5	5					
Incremental Out-performance 06/07		-10	-10	-10	-10	-10				
Incremental Out-performance 07/08			10	10	10	10	10			
Incremental Out-performance 08/09				0	0	0	0	0		
Incremental Out-performance 09/10					?	?	?	?	?	
Adjustment for underperformance						-10				
Final incentive payment						0	10	0	0	

The incremental underperformance in 2006/07 of 10 is taken into account in 2010/11 when calculating the incentive payment for that year. As a result, the incentive payment in 2010/11 becomes zero. In a situation where in a given year the carried forward incremental underperformance is greater than incremental outperformance, the incentive payment for that year will be set at zero (given that the incentive payment is constrained not to be negative). However, the remaining incremental underperformance will be carried forward to the next year and so on. The company will only receive positive incentive payments once the full incremental underperformance has been offset against incremental outperformance during the price control period in which the incentive payments apply (i.e. in this example DPCR5).

Table 2 also shows that incremental outperformance is calculated in relation to the highest previous saving in that period. Thus, the incremental outperformance in year 2007/08 is calculated in relation to the previous highest actual outperformance (which is 5 in year 2005/06) and therefore the incentive payment for 2007/08 is 15-5=10 and <u>not</u> 15- (-5)=20.

The capex rolling adjustment

This section sets out how the capex roller will be applied to capex efficiency savings made during the DPCR3 period. For the purpose of this example, it is assumed that the company has met its quality of service and security of supply obligations and hence is allowed to retain the benefits of all capex savings.

The capex roller aims at removing periodicity. Without the capex roller the company benefits most from savings at the start of the price control period and has a weaker incentive to make savings in the latter years of the price control period. The capex roller removes this periodicity by allowing the company to retain depreciation and cost of capital of the efficiency saving for a five year period.

It is proposed that the rolling adjustment uses the same broad principles as those applied in calculating the Regulatory Asset Value (RAV). Calculating the annual incentive payment (i.e. the annual benefit accruing to the company in each relevant year) for differences between actual and projected capex (excluding metering)[28] depends on the:

- **allowed cost of capital** – the incentive payment will be calculated using the allowed cost of capital **that has applied during this price control period, (i.e.**

[28] As per the December 1999 Reviews of Public Electricity Suppliers 1998 to 2000, Final Proposals, paragraph 5.37

6.5 per cent pre-tax real) and companies will be allowed to retain the full cost of capital benefits of any capex efficiencies that they achieve;

- **assumed asset life** – no adjustments will be made to the asset lives that are currently in place for the purpose of calculating the incentive payment; and

- **depreciation allowance** – companies will be allowed to retain the full depreciation benefits of any capex efficiencies that they achieve based on the existing depreciation policy and assumed asset lives.

DPCR3 allowed 3% depreciation until pre-vesting assets are fully depreciated and then 5% in practice, but throughout this appendix an average asset life of 25 years has been assumed for simplicity (i.e. 4% depreciation).

In the following simple example, the working of the capex roller is illustrated in its simplest form, without references to the RAV. It is assumed that the capex allowance for year 2000/01 was 100, but actual spend was 75.

Table 3 The capex roller in its basic form

Illustrative Capex Incentive Scheme

Asset life (yrs)	25
WACC	6.5%

Capex assumptions	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
PC Allowance	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Actual Capital Expenditure	75.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incentive Scheme Roller										
Opening balance	0.00	25.00	24.00	23.00	22.00	21.00	0.00	0.00	0.00	0.00
Outperformance in year	25.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation		-1.00	-1.00	-1.00	-1.00	-1.00	0.00	0.00	0.00	0.00
Closing balance	25.00	24.00	23.00	22.00	21.00	20.00	0.00	0.00	0.00	0.00
Expired Outperformance						-20.00	0.00	0.00	0.00	0.00
Incentive Payment										
Depreciation						1.00	0.00	0.00	0.00	0.00
Return						1.33	0.00	0.00	0.00	0.00
Total						**2.33**	**0.00**	**0.00**	**0.00**	**0.00**

In the above example, the company receives depreciation of 25/25 = 1 and a 6.5% return over the average of the opening and closing balances for the year in question. The actual incentive payment in the first year of DPCR4 is 1.34 (i.e. one year depreciation and half a year return), given that the company has already received 4.5 years of return on the saving during the DPCR3 period.

The next example illustrates the working of the capex roller through the RAV. For the same saving in year 1 of DPCR3 (i.e. as in the previous example), the incentive payment will be the same, i.e. 1.34.

During DPCR3 the company receives both the cost of capital and depreciation over the full capex allowance (i.e. over 100). The capex roller does not have an impact on this and hence the calculation of allowed income (proposed – i.e. with capex roller) and the calculation of allowed income (previous – i.e. without capex roller) in the above table is exactly the same during the DPCR3 period (i.e. no incentive payment is made, because the company already keeps the benefits of outperformance).

Table 4 Capex saving in year 1 through the RAV

Illustrative Capex Incentive Scheme										
Asset life (yrs)	25									
Capex assumptions										
PC Allowance	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Actual Capital Expenditure	75.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rolling RAV (Proposed)	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Opening RAV	**0.00**	**100.00**	**96.00**	**92.00**	**88.00**	**84.00**	**60.00**	**57.00**	**54.00**	**51.00**
Additons	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rolling Depreciation	0.00	-4.00	-4.00	-4.00	-4.00	-4.00	-3.00	-3.00	-3.00	-3.00
Adjustments to RAV										
Rolling Adjustment (capex)	0.00	0.00	0.00	0.00	0.00	-25.00	0.00	0.00	0.00	0.00
Rolling Adjustment (depreciation)	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00
Closing Rolling RAV	**100.00**	**96.00**	**92.00**	**88.00**	**84.00**	**60.00**	**57.00**	**54.00**	**51.00**	**48.00**
Previous approach - RAV	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Opening RAV	**0.00**	**100.00**	**96.00**	**92.00**	**88.00**	**63.00**	**60.00**	**57.00**	**54.00**	**51.00**
Capital Expenditure in Year	75.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Allowance in Year	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Calculation of Allowed Depreciation										
Depreciation	0.00	-4.00	-4.00	-4.00	-4.00	-3.00	-3.00	-3.00	-3.00	-3.00
Closing Previous RAV	**100.00**	**96.00**	**92.00**	**88.00**	**84.00**	**60.00**	**57.00**	**54.00**	**51.00**	**48.00**
Shadow RAV (Actual capex)	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Opening RAV	0.00	75.00	72.00	69.00	66.00	63.00	60.00	57.00	54.00	51.00
Capital Expenditure in Year	75.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Actual Cumulative Additions for Depreciation Calculation	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Depreciation	0.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00
Closing shadow RAV	75.00	72.00	69.00	66.00	63.00	60.00	57.00	54.00	51.00	48.00
Income (Proposed)	**3.25**	**10.37**	**10.11**	**9.85**	**9.59**	**6.34**	**6.80**	**6.61**	**6.41**	**6.22**
Income (Previous)	**3.25**	**10.37**	**10.11**	**9.85**	**9.59**	**5.00**	**6.80**	**6.61**	**6.41**	**6.22**
INCENTIVE PAYMENT	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1.34**	**0.00**	**0.00**	**0.00**	**0.00**
Calculation of Allowed Income (Proposed)										
Rate of return	**6.5%**									
Allowed Depreciation	0.00	4.00	4.00	4.00	4.00	4.00	3.00	3.00	3.00	3.00
Allowed Return	3.25	6.37	6.11	5.85	5.59	2.34	3.80	3.61	3.41	3.22
Total Income	**3.25**	**10.37**	**10.11**	**9.85**	**9.59**	**6.34**	**6.80**	**6.61**	**6.41**	**6.22**
Calculation of Allowed Income (Previous)										
Rate of return	**6.5%**									
Allowed Depreciation	0.00	4.00	4.00	4.00	4.00	3.00	3.00	3.00	3.00	3.00
Allowed Return	3.25	6.37	6.11	5.85	5.59	2.00	3.80	3.61	3.41	3.22
Total Income	**3.25**	**10.37**	**10.11**	**9.85**	**9.59**	**5.00**	**6.80**	**6.61**	**6.41**	**6.22**

In the above example, depreciation for 2001/02 is calculated as 100/25=4, i.e. the depreciation is calculated over actual spend plus outperformance. The return in 2000/01 is calculated as 0.5 [29] times the allowed cost of capital times the full allowance (i.e. actual spend plus outperformance), i.e. 0.5*0.065*100=3.25. The return for 2001/02 is calculated as the cost of capital over the average of the opening RAV and

[29] It is assumed that revenues and costs accrue evenly over the year and hence instead of allowing a return at the end of the year, a return is allowed over half the first year.

closing RAV for that year, i.e. $0.065*((100+96)/2)=6.37$. The return for 2002/03 is calculated as $0.065*((96+92)/2)=6.11$.

The first effect of the capex roller is visible in the first year of DPCR4 by allowing an incentive payment for the capex saving made in 2000/01. The company has already received 4 years of depreciation. The incentive payment therefore consist of a final depreciation payment of 4 of which 1 relates to the depreciated outperformance (i.e. 25/25) and 3 refers to depreciated actual spend (i.e. $75/25=3$), without the capex roller the company would only have received the latter. The company also receives a return of 6.5% (DPCR3 cost of capital) over the average of the opening and closing RAV i.e. $0.5*0.065*((84+60)/2)=$ 2.34. The company receives return over half a year as it already has received 4.5 years of return by then.

Without the capex roller the company would have received $0.5*0.065*((63+60/2)=2$. The value of the incentive payment in 2005/06 is therefore $(2.34+4)\text{-}(2+3)=1.34$. The example in table 4 above shows a capex efficiency saving in the first year of the price control. The next table shows a capex saving of the same size but in the second year of the price control.

Table 5 Capex saving in year 2 through the RAV

Illustrative Capex Incentive Scheme										
Asset life (yrs)	25									
Capex assumptions										
PC Allowance	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Actual Capital Expenditure	0.00	75.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rolling RAV (Proposed)	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Opening RAV	**0.00**	**0.00**	**100.00**	**96.00**	**92.00**	**88.00**	**84.00**	**60.00**	**57.00**	**54.00**
Additons	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rolling Depreciation	0.00	0.00	-4.00	-4.00	-4.00	-4.00	-4.00	-3.00	-3.00	-3.00
Adjustments to RAV										
Rolling Adjustment (capex)	0.00	0.00	0.00	0.00	0.00	0.00	-25.00	0.00	0.00	0.00
Rolling Adjustment (depreciation)	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00
Closing Rolling RAV	**0.00**	**100.00**	**96.00**	**92.00**	**88.00**	**84.00**	**60.00**	**57.00**	**54.00**	**51.00**
Previous RAV	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Opening RAV	**0.00**	**0.00**	**100.00**	**96.00**	**92.00**	**66.00**	**63.00**	**60.00**	**57.00**	**54.00**
Capital Expenditure in Year	0.00	75.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Allowance in Year	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Calculation of Allowed Depreciation										
Depreciation	0.00	0.00	-4.00	-4.00	-4.00	-3.00	-3.00	-3.00	-3.00	-3.00
Closing Previous RAV	**0.00**	**100.00**	**96.00**	**92.00**	**88.00**	**63.00**	**60.00**	**57.00**	**54.00**	**51.00**
Shadow RAV	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Opening RAV	0.00	0.00	75.00	72.00	69.00	66.00	63.00	60.00	57.00	54.00
Capital Expenditure in Year	0.00	75.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Actual Cumulative Additions for Depreciation Calculation	0.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Depreciation	0.00	0.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00
Closing Shadow RAV	0.00	75.00	72.00	69.00	66.00	63.00	60.00	57.00	54.00	51.00
Income (Proposed)	**0.00**	**3.25**	**10.37**	**10.11**	**9.85**	**9.59**	**6.34**	**6.80**	**6.61**	**6.41**
Income (Previous)	**0.00**	**3.25**	**10.37**	**10.11**	**9.85**	**7.19**	**5.00**	**6.80**	**6.61**	**6.41**
INCENTIVE PAYMENT	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**2.40**	**1.34**	**0.00**	**0.00**	**0.00**
Calculation of Allowed Income (Proposed)										
Rate of return	**6.5%**									
Allowed Depreciation	0.00	0.00	4.00	4.00	4.00	4.00	4.00	3.00	3.00	3.00
Allowed Return	0.00	3.25	6.37	6.11	5.85	5.59	2.34	3.80	3.61	3.41
Total Income	**0.00**	**3.25**	**10.37**	**10.11**	**9.85**	**9.59**	**6.34**	**6.80**	**6.61**	**6.41**
Calculation of Allowed Income (Previous)										
Rate of return	**6.5%**									
Allowed Depreciation	0.00	0.00	4.00	4.00	4.00	3.00	3.00	3.00	3.00	3.00
Allowed Return	0.00	3.25	6.37	6.11	5.85	4.19	2.00	3.80	3.61	3.41
Total Income	**0.00**	**3.25**	**10.37**	**10.11**	**9.85**	**7.19**	**5.00**	**6.80**	**6.61**	**6.41**

As the above table shows, the incentive payment to the company in DPCR4 for a capex saving made in DPCR3 is 2.40 in 2005/6 and 1.34 in 2006/7.

Appendix 2 The losses incentive

This Appendix sets out the operation of the rolling retention mechanism for the losses incentive. It also illustrates the operation of the proposed 'LAF floor' adjustment for distributed generation.

Rolling retention mechanism

Table 1 shows a simple example of a permanent reduction in losses in year 3 of the price control period.

Table 1: Rolling retention mechanism for permanent reduction in losses in year 3

	DPCR 4					DPCR 5				
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
units distributed[30]	100	101	102.01	103.03	104.06					
target loss percentage	5%	5%	5%	5%	5%					
allowed losses (AL)	5	5.05	5.10	5.15	5.20					
actual losses (L)	5	5.05	4.10	4.15	4.20					
AL - L	0	0	1	1	1					
Incremental difference[31]	0	0	-1	0	0					
Incremental difference (2007/08)			-1	-1	-1	-1	-1			
Adjustment [32]						**1**	**1**	**0**	**0**	**0**

The adjustment in the years following the revision of the target (i.e. 2010/11 and 2011/12 in the example) can be made by increasing allowed losses. A positive adjustment represents a reward for the DNO. Therefore, in table 1 the DNO benefits for

[30] It is assumed that, ceteris paribus, there is annual growth of 1% in units distributed and units lost.
[31] The incremental difference in year t is calculated as equal to $(AL\text{-}L)_t$ – sum of previous incremental differences under fixed target. The incremental difference in year 1 is equal to: $-[AL_t-(D_t*(L_{t-1}/D_{t-1}))]$
[32] The adjustment, made after the revision of the fixed target, is the negative sum of the incremental differences over the previous 4 years.

five years from a permanent reduction in losses in 2007/08. Similarly, the DNO would be penalised by a negative adjustment if losses had permanently increased in 2007/08.

Table 2 contains a more complicated example of the rolling retention mechanism.

Table 2 Rolling incentive mechanism with multiple changes in losses

	DPCR 4					DPCR 5				
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
units distributed	100	100	100	100	100					
target loss percentage	5%	5%	5%	5%	5%					
allowed losses (AL)	5	5	5	5	5					
actual losses (L)	4	10	6	2	5					
AL – L	1	-5	-1	3	0					
Incremental difference[33]	-1	6	-4	-4	3					
Incremental difference (2005/06)	-1	-1	-1	-1	-1					
Incremental difference (2006/07)		6	6	6	6	6				
Incremental difference (2007/08)			-4	-4	-4	-4	-4			
Incremental difference (2008/09)				-4	-4	-4	-4	-4		
Incremental difference (2009/10)					3	3	3	3	3	
Adjustment						**-1**	**5**	**1**	**-3**	**0**

[33] It is assumed that in 2004/05, units distributed were 100 and units lost were 5

Adjustment for distributed generation

The example in table 3 demonstrates the operation of the adjustment for distributed generation. This example is based on a 'LAF floor' of 0.99 and highlights the effect of the connection of generators with a LAF of 0.98.

Table 3: Adjustment for distributed generation

Year	2005/06	2006/07	2007/08	2008/09	2009/10
Allowed losses (AL)	100	100	100	100	100
Recorded losses (L)	99.4	99.8	100	100	100.2
(AL-L)	**0.6**	**0.2**	**0**	**0**	**-0.2**
DG output	20	40	50	50	60
Losses associated with DG	0.4	0.8	1	1	1.2
Losses associated with LAF floor	0.2	0.4	0.5	0.5	0.6
'Excess' losses	0.2	0.4	0.5	0.5	0.6
adjusted allowed losses ('AL')	100.2	100.4	100.5	100.5	100.6
(AL'-L)	**0.8**	**0.6**	**0.5**	**0.5**	**0.4**

In this example, the DNO receives a declining benefit through the losses incentive owing to the increased losses being driven by the increased output of the distributed generation. However, the decline is smaller than the unadjusted decline. In addition, the DNO will receive payments through the distributed generation incentive.

This example focuses on the case where a generator increases losses on a distribution network. In many cases, distributed generation will reduce, rather than increase, losses. Under the proposed losses incentive, DNOs will share in the benefit of this, providing an additional incentive on them to facilitate the connection of distributed generation. Where distributed generation increases losses, DNOs will be substantially, but not completely, protected against the resulting costs.

Appendix 3 Developing a RIA for metering

Objective

Ofgem's overall objective in relation to electricity metering is to secure effective competition in the provision of metering services, and to remove unnecessary regulation as competition develops. This specific policy is part of the work towards achieving that aim.

Overview of key issues

The meter is the interface between the customer and the supplier acting as the suppliers "till" and providing consumption information to customers. Effective competition in the provision of metering services will correctly align the interests of purchasers and providers of metering services.

Options

The design of a control is split into three elements, although there are interactions between the elements and they should not be considered entirely in isolation from one another:

- ♦ scope – i.e. which activities should be covered by a price control;
- ♦ form – i.e. how should the control work; and
- ♦ duration – i.e. when should the control end and what criteria for its removal should be used.

Ofgem has consulted on these options in July and December and set out its further thinking in Chapter 3 of this document. It is not intended to replicate those discussions in this RIA.

The large policy decision that needs to be taken is whether a price control is necessary for some or all metering activities or whether Ofgem can rely on competition and *ex-post* regulation to protect the interests of consumers. A related policy question is whether the obligations on DNOs to provide metering services should be lifted. These are questions of the extent and speed of deregulation and this RIA primarily addresses itself to those issues.

Risk and unintended consequences

Removing the obligations to provide services before competition is sufficiently developed could force Ofgem to rely on the powers available under competition law to ensure suppliers are able to obtain metering services which can take longer to arrive at a result.

DNOs have expressed concerns about undue premature replacement of metering assets and the stranding of their costs. Ofgem remains of the view that a correctly designed price control and the opportunity for DNOs to win business out of area will mitigate these risks, however to the extent that they do occur they will be consequences that were not intended.

Competition

The intention of this policy is to protect consumers' interests better by securing effective competition in the provision of electricity metering services. A binding price control will directly influence the pricing of the dominant incumbents in the market for metering services. Currently these incumbents have market shares varying from the high 90s to 100%. This policy will therefore have on impact on the competitive environment in metering markets.

Costs and benefits

An important part of the work Ofgem is undertaking to consider the costs and benefits of price controlling metering and retaining obligations to provide services is to carry out a competition assessment or competitive market review (CMR).

Ofgem intends to issue a survey to industry participants to help assess the development and potential for competition in metering. Copies of this survey are available on Ofgem's website.

The introduction of explicit metering price controls will also lead to changes in the pricing of current DNOs. There may be some costs associated with making these changes known.

Environmental

There are no direct environmental implications of this policy. However flexibility in metering arrangements may be beneficial in other policy areas (for example allowing the introduction of alternative metering technologies that give better real time information to customers) that have environmental implications.

Security of supply

There are no direct supply security implications of this policy. However flexibility in metering arrangements may be beneficial in other policy areas (for instance increasing demand side participation in wholesale markets) that have security of supply implications.

Summary of costs and benefits

Views are sought on the costs and benefits of the various options. Ofgem's general principal remains that a market mechanism is a superior mechanism for gathering and coordinating the interests of diverse parties than an imposed regulatory solution.

Distributional impacts including social impacts

Currently the differential between prepayment and credit meters is explicitly capped (at £15 per annum in most DNO regions).

If the cap is a binding constraint changes to it could affect the price differential between prepayment and credit meters. This could increase the costs for prepayment customers, who tend to have lower average incomes than credit customers.

Views are therefore welcomed on whether the £15 cap is currently binding and whether the benefits from any loosening or removal of the cap would outweigh the costs. Particular emphasis in responses should be given to the impact on low income customers and customers in fuel poverty.

Review and compliance

Compliance will be determined in accordance with the usual procedures for assessing compliance with price controls.

Ofgem will assess this policy as part of its ongoing work reviewing competition in metering markets. The data collected in the current CMR will form part of an ongoing dataset used by Ofgem for this purpose.

Conclusion

Ofgem will separate metering price controls from distribution price controls with effect from 1 April 2005. Specifics of the decision will be informed by the CMR, responses to consultation and responses to this initial RIA.

Appendix 4 Developing a RIA for quality of service

Introduction

It was explained in previous consultation documents that, where appropriate, Ofgem would produce RIAs for significant new policies introduced as the price control review progresses. Chapter 4 of this document sets out further thoughts and options for the main areas of the quality of supply arrangements including:

- standards of performance;
- the IIP quality of service incentive scheme;
- network resilience;
- telephony incentives; and
- environmental outputs.

This Appendix sets out questions that need to be answered in developing a full RIA for quality of supply; and in particular to assess the relative costs and benefits of the various measures included within the revised framework, as described above. Ofgem would welcome responses to the questions. A revised version of the quality of service RIA will be set out in the June Initial Proposals and a final version in the September update paper.

Objectives and key issues

The objectives and key issues in respect of the changes to the quality of supply arrangements are set out in Chapter 4 and in previous consultation documents.

Options

The options for revising the quality of supply arrangements are discussed in detail in this and in earlier price control documents. They are summarised below.

For **standards of performance** the broad options that have been considered are:

- "do nothing" – the existing standards of performance arrangements could be maintained for the next price control period.

- revised arrangements – Ofgem is proposing to introduce revised arrangements for storm conditions (discussed further below), and remove the overall standards of performance. Ofgem is considering revising the supply restoration standard for HV connected consumers if there is sufficient willingness to pay for such changes.

The **existing quality of service incentive scheme** runs until 31 March 2005. It is therefore necessary to develop a scheme for the next price control period. The broad options that have been considered are:

- a similar scheme with penalties for failing to meet targets each year and rewards for outperformance over the duration of the scheme. The impact of exceptional events would be excluded provided companies have taken appropriate mitigating actions;

- revised arrangements – Ofgem is proposing to introduce an incentive scheme with rewards for beating targets and penalties for failing to meet targets each year based on willingness to pay information. The impact of storm events would be fully excluded. (Separate arrangements for resilience are discussed below.) The initial proposals for targets and incentive rates will be set out in the June consultation paper.

For **network resilience** the broad options that have been considered are:

- "do nothing" – it would be possible to rely on existing Electricity Act licence requirements such as company having a duty to "maintain an economic, efficient system" and compliance with the Electricity, Supply, Quality and Continuity Regulations 2002; or

- developing more robust measures of network resilience and strengthening the existing arrangements for storms payments – Ofgem is proposing to work with the DNOs to develop measures for network resilience. It is also proposing to increase the DNOs' exposure to the arrangements for storm payments, apply a shorter threshold for payments becoming due in "medium-sized" events and incentivise DNOs to be more pro-active in making payments.

For **telephony incentives** two broad options have been considered:

- retaining a relative incentive scheme based on monthly surveys for the quality of telephone response received by consumers who speak to an agent and introducing an incentive scheme for the speed of telephone response; or

- using a survey-based approach for incentivising both the speed and quality of telephone response. Ofgem is proposing that the scope of the scheme should be extended to calls answered by automated messaging.

For **environmental outputs** two broad options have been considered:

- "do nothing" – rely on existing reporting requirements to other environmental regulators; or

- introducing a limited set of reporting requirements similar to data that was previously collected by the Electricity Association.

Costs and benefits

In developing the quality of supply framework, it is important that the main costs and benefits are identified, and where possible quantified, to ensure that the introduction of the new policy is appropriate.

Two key quantitative sources of information on the costs and benefits of quality of supply initiatives are the forecast business plan questionnaires (FBPQs) and Ofgem's consumer survey work on willingness to pay. PB Power is currently reviewing the assumptions made by the DNOs in their forecast BPQ returns. The results of this and additional work being undertaken by Ofgem will feed into to an assessment of the efficient level of costs of delivering quality of supply improvements.

However, it is also important that Ofgem can take into account a wider range of views on the impact of changes in the quality of supply arrangements on consumers and DNOs. Specific questions on which respondents are requested to comment are set out below although Ofgem welcomes any other information that will assist the development of the RIA. Any assumptions that respondents make in answering these questions should be clearly identified.

Questions for developing the RIA:

- what would be the costs and benefits of the proposed changes in each of the areas described above? Can these be quantified?
- what would be the impact of the proposed changes in each of these areas on other incentives in the price control framework (e.g. capex & opex rolling incentives/DG/losses)?
- are there any additional costs of the introducing the revised framework to DNOs/Ofgem/other parties? If so, what are these?
- are there any impacts on safety?
- what will be the impact of the proposed changes on the long term reliability of the networks;
- what are the potential costs and benefits of increased investment in network resilience?
- what are the potential costs and benefits of increased investment in undergrounding for visual amenity reasons?

Distributional effects

When considering the distributional effects of the proposed changes to the quality of supply arrangements, it is important to consider the extent to which they will impact on different consumers groups:

- are these measures likely to benefit all consumers connected to the DNOs' network?
- which consumers are likely to gain most or benefit least from the changes?

Risks and unintended consequences

There could be a number of risks and unintended consequences associated with the revised framework of quality of supply measures. Some of these will be influenced by the value (strength) of any incentive provided. For example, if an incentive is too strong it may encourage inefficient expenditure, but if it is not strong enough it may not have the desired impact on DNO's behaviour and the expected benefits may not be realised. Answers to the questions that have been identified above will help in assessing the appropriate level of any incentive, but it is important to consider whether there are any other potential risks or unintended consequences. For example, for the quality of service incentive scheme there may be a risk that penalties under scheme are not passed to consumers in the form of lower bills (i.e. suppliers retain benefit of reduced DUoS charges if there is a penalty).

Ofgem would welcome views in this area, including where possible quantification of the likely impact.

Competition

Views are invited on the impact of the proposed changes to the quality of supply framework on competition.

Review and compliance

Views are invited on the likely costs of any monitoring that would be required for each aspect of the revised framework, and in particular for the quality of service incentive scheme and standards of performance.

Appendix 5 Summary of forecast cost information

Summary of forecasts - Aquila

FINANCIAL SUMMARY			2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
	real 2002/03 prices		Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	1,260.7	1,319.8	1,365	1,462	16%
	Excluded Services	£m	126.2	135.0	135.0	135.0	7%
	Deminimis	£m	-	-	-	-	
	Other income	£m	128.3	87.3	87.3	87.3	-32%
Total Revenue		£m	1,515.2	1,542.1	1,587.5	1,684.3	11%
Operating Costs	Cost of sales	£m	52.5	66.1	66.1	66.1	26%
	Exit Charges (NGC and other)	£m	98.3	88.8	88.8	88.8	-10%
	Employee Wages	£m	47.0	9.8	9.8	9.8	-79%
	Direct Network Costs	£m	210.5	255.5	255.5	270	28%
	Depreciation	£m	202.5	241.4	241.4	246	22%
	Network Rates	£m	118.1	117.0	117.0	117.0	-1%
	Other Costs	£m	114.3	77.2	77.2	82.0	-28%
Total Operating Costs		£m	843.2	855.8	855.8	880.4	4%
Capital Expenditure	Load Related	£m	258.7	276.9	276.9	276.9	7%
	Capital Contributions	£m	(138.3)	(149.2)	(149.2)	(149.2)	8%
	Non Load Related	£m	347.4	510.1	549.9	638.8	84%
	Non-operational Capex	£m	10.6	-	-	-	-100%
Total Capital Expenditure		£m	478.4	637.8	677.6	766.5	60%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	2.3	2.4			
Unplanned Customer Minutes Lost	mins	87.7	97.8	86.6	86	-2%
Unplanned Customer interruptions per 100 customers		95.4	106	98.4	98	3%

REVENUE CHANGES				Base Case	QoS Case	DNO Case
Po	2005	Increase		6.0	9.7	17.6
X	2006-2009	Increase		1.0	1.0	1.0

DNO's STRATEGY & INVESTMENT PLAN

Efficiency savings of 1.5% per annum have been built into the expenditure plans for all 3 scenarios on top of making significant opex savings during the current price control.

Overall costs increase however as a result of the possible imposition of lane rentals, increasing pension costs, environmental and health and safety obligations and increasing pressure on labour and material prices.

The base case assumes maintaining the average 2001/02 - 2002/03 QoS performance for 2005/06 to 2009/10, which is achieved by increasing investment to start to replace an ageing asset base, and hence prevent a deterioration in network reliability.

In the QoS case, the reliability of supply of rural customers in particular will improve as part of the investment strategy deployed through refurbishment and upgrading of the overhead network, and network reconfiguration that will reduce the length and number of customers per circuit. The QoS investment will reduce customer interruptions by 7.7 and customer minutes lost by 10.9 minutes compared with the average 2001/02 - 2002/03 performance.

The DNO case is Aquila's preferred scenario, and is designed not only to achieve the above customer interruption and customer minutes lost benefits, but also to improve network resilience to customers, by undergrounding 2% of the network that is particularly vulnerable to storm conditions, and improve environmental performance in respect of visual amenity and replacement of some fluid filled cables.

The DNO case represents best value to customers.

The significant investment burden resulting from the delivery of these plans will require funding.

Although the investment plans will provide significant benefit to customers, particularly those located in rural areas, the impact on customer bills is limited, for example, the base case will lead to a typical domestic customer's bill increasing by £5 per annum by 2010.

Aquila has undertaken changes in its structure during the first few years of the current price control which has impacted on the detailed analysis of costs.

Whilst we have supported Ofgem in publishing this data, it should be recognised that this data has not been normalised, and cannot therefore necessarily be compared to other DNOs, there is no common definition of Po, and different assumptions have been used by DNOs in deriving total revenues.

Summary of forecasts - East Midlands Electricity

FINANCIAL SUMMARY			2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
	real 2002/03 prices		Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	1,271.0	1,310.1	n/a	1,315.8	4%
	Excluded Services	£m	102.7	98.2	n/a	98.4	-4%
	Deminimis	£m	5.6	11.1	n/a	11.1	98%
	Other income	£m	124.1	78.9	n/a	78.9	-36%
Total Revenue		£m	1,503.4	1,498.4	-	1,504.2	0%
Operating Costs	Cost of sales	£m	38.4	38.9	38.9	38.9	1%
	Exit Charges (NGC and other)	£m	93.7	70.9	70.9	70.9	-24%
	Employee Wages	£m	100.4	94.0	94.0	92.2	-8%
	Direct Network Costs	£m	115.1	115.1	115.1	115.4	0%
	Depreciation	£m	186.4	219.7	219.7	220.5	18%
	Network Rates	£m	120.6	127.4	127.4	127.4	6%
	Other Costs	£m	159.0	150.9	150.9	150.1	-6%
Total Operating Costs		£m	813.7	816.9	816.9	815.4	0%
Capital Expenditure	Load Related	£m	325.7	455.7	455.7	452.8	39%
	Capital Contributions	£m	(198.1)	(236.2)	(236.2)	(237.1)	20%
	Non Load Related	£m	261.5	472.8	528.8	514.9	97%
	Non-operational Capex	£m	19.3	6.2	6.2	6.2	-68%
Total Capital Expenditure		£m	408.4	698.5	754.5	736.8	80%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	2.4	2.6			
Unplanned Customer Minutes Lost per Connected Customer	mins	79.3	66.5	62.3	62.4	-21%
Unplanned Customer interruptions per 100 customers		73.5	82.9	74.9	78.5	7%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005	Increase	2.1%	n/a	2.2%
X	2006-2009	Increase	2.1%	n/a	2.2%

DNO's STRATEGY & INVESTMENT PLAN

The Base Case contains the increased levels of expenditure on asset replacement and refurbishment that is necessary to maintain current network performance and prevent deterioration.

EME had the lowest capital allowances in the existing DPCR3 period. The increase means that Base Case spend is now in-line with capital spending of other similarly sized DNOs.

The required increase in capital investment will reduce the average life of assets before replacement from the current 140 years to around 104 years.
This still shows a dramatic extension of life over design life. This move to a sustainable network would cost the average domestic customer only £6.50 pa by 2010, on a £300 electricity bill.

The Quality of Supply Scenario includes additional investment to improve network performance for customers. 11kV circuits are targeted since these contribute most to circuit performance. The work involves both increased levels of overhead line refurbishment / replacement and investment in network automation targeted at those groups of circuits with the worst historical performance.

The DNO Case is EME's Preferred Scenario - offering best value for money with a balance of deliverables and outputs. There is a modest increase to the Base Case investment in the areas of network performance and environmental improvement, particularly targeting visual amenity. This will result in a general improvement in network resilience with reductions in both Customer Interruptions and Customer Minutes Lost.

EME has made significant operating cost savings during the DPCR3 period, and forecasts further underlying efficiency savings averaging 1.5% pa throughout the DPCR4 period.

Operating costs rise in total over the period. This is primarily due to lane rental (a new obligation), increasing inspection and maintenance requirements and increased costs due to scarce technical skills and pension costs.

We have supported Ofgem in publication of this data, but it should be recognised that data has not been normalised, and therefore may not be comparable to other DNOs. There is no common definition of Po and DNOs have used different assumptions in revenue calculations.

Summary of forecasts - EPN

FINANCIAL SUMMARY		real 2002/03 prices	2000/01-2004/05	Five Year Total 2005/06-2009/10			% change	
			Total	Base Case	QoS Case	DNO Case		DNO Case v Total
Revenue	Price controlled	£m	1,517	1,613	n/a	1,635		7.8%
	Excluded Services	£m	73	58	n/a	58		-20.6%
	Deminimis	£m	0	-	n/a	-		-100.0%
	Other income	£m	131	123	n/a	123		-6.5%
Total Revenue		£m	1,720	1,793	-	1,815		5.5%
Operating Costs	Cost of sales	£m	(11)	-	-	-		-100.0%
	Exit Charges (NGC and other)	£m	(96)	(123)	(123)	(123)	1)	27.0%
	Employee Wages	£m	(95)	(118)	(118)	(118)	2)	24.2%
	Direct Network Costs	£m	(138)	(199)	(199)	(199)	3)	44.1%
	Depreciation	£m	(181)	(293)	(298)	(297)	4)	64.1%
	Network Rates	£m	(129)	(126)	(126)	(126)		-2.4%
	Other Costs	£m	(119)	(139)	(139)	(139)	5)	17.0%
Total Operating Costs		£m	(769)	(998)	(1,002)	(1,002)		30.2%
Capital Expenditure	Load Related	£m	(422)	(588)	(588)	(598)		41.8%
	Capital Contributions	£m	260	233	233	233		-10.2%
	Non Load Related	£m	(459)	(689)	(836)	(726)		58.1%
	Non-operational Capex	£m	(20)	(51)	(51)	(58)	6)	190.8%
Total Capital Expenditure		£m	(641)	(1,094)	(1,243)	(1,149)		79.2%

1) Increase due to NGC's proposed replacement and modification programme.

2) Increased Employee costs relate primarily to recovery of Pension deficit, including that relating to 24Seven staff within Network costs.

3) Increase primarily additional Tree cutting expenditure.

4) Increase due to additional investment in the Network.

5) Increased Other costs due to inclusion of 24Seven insurance from 2003/4.

6) Increased Non Op Capex due to inclusion of 24Seven IT from 2003/4.

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	3.4	3.5			
Unplanned Customer Minutes Lost per Connected Customer	mins	78	82	81	76	-2.6%
Unplanned Customer interruptions per 100 customers		86	94	91	81	-5.5%

REVENUE CHANGES				Base Case	QoS Case	DNO Case
Po increase/(decrease)	2005			8.3%	n/a	9.6%
X increase/(decrease)	2006-2009			0.0%	n/a	0.0%

The costs for 2002/3 actuals and all forecast years have been adjusted to remove margins included in charges from 24Seven, a related-company service provider. Salary Costs included in charges from 24Seven have been reclassified to the Employee Wages line from the Direct Network Costs line.

DNO's STRATEGY & INVESTMENT PLAN

The main objectives of our investment strategy are:

1.To ensure the business can continue to meet its (increasing) legal and regulatory obligations to operate and maintain a safe, environmentally friendly, economical, and co-ordinated distribution network.
2.To deal with a peak workload in the replacement of ageing assets that can be deferred no longer because of the operation and safety concerns arising from their condition.
3.To meet tougher quality of supply targets, to which are attached financial incentives for success and penalties for failure.
4.To meet increasing demand for new network capacity in our home areas, and for new connections to our networks, arising from general load growth and development, and also from government-sponsored embedded generation and regional regeneration programmes.
5.To maintain the efficiency, security, and integrity of our existing networks, while meeting the challenge of competition from embedded distributors.

The key highlights of our investment plan are:

1.Reinforcement, load transfer, or enhanced cooling schemes in respect of all main substations at risk of P2/5 non-compliance within the DPCR4 period. Major reinforcement schemes are planned in Luton, South Benfleet, Canvey Island, Harlow, Turnford, Rye House, Fulbourne, and Huntingdon areas.
2.Significant network development to support government redevelopment areas at Thames Gateway, the Stansted/Cambridge Corridor, and Milton Keynes.
3.Additional remote control and automation on both rural and urban networks to achieve Ofgem's 2010 benchmark QoS levels.
4.Replacement of approximately 1,400km of bare LV overhead line conductor with Aerial Bundled Conductor (ABC).
5.Refurbishment or uprating of 132kV steel tower lines and 33kV overhead lines. Major schemes are planned for Felixstowe, Cranham, and Dunmow.
6.Replacement of 25% of 132kV switchgear and 24% of 33kV life-expired switchgear. Major replacement schemes are planned for Tilbury, Mill Hill in north London, and Rayleigh.

Summary of forecasts - LPN

FINANCIAL SUMMARY	real 2002/03 prices		2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
			Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	1,127	1,313	n/a	1,328	17.8%
	Excluded Services	£m	83	57	n/a	57	-31.6%
	Deminimis	£m	-	-	n/a		-
	Other income	£m	120	110	n/a	110	-8.5%
Total Revenue		£m	1,331	1,480	-	1,495	12.4%
Operating Costs	Cost of sales	£m	(6)	-	n/a	-	-100.0%
	Exit Charges (NGC and other)	£m	(90)	(110)	n/a	(110)	1) 21.4%
	Employee Wages	£m	(69)	(209)	n/a	(209)	2) 205.1%
	Direct Network Costs	£m	(113)	(93)	n/a	(93)	-17.8%
	Depreciation	£m	(210)	(219)	n/a	(228)	3) 8.4%
	Network Rates	£m	(106)	(104)	n/a	(104)	-2.7%
	Other Costs	£m	(101)	(102)	n/a	(102)	0.9%
Total Operating Costs		£m	(696)	(836)	-	(845)	21.5%
Capital Expenditure	Load Related	£m	(278)	(364)	n/a	(362)	30.0%
	Capital Contributions	£m	206	169	n/a	169	-18.0%
	Non Load Related	£m	(340)	(596)	n/a	(604)	77.8%
	Non-operational Capex	£m	(13)	(39)	n/a	(53)	297.2%
Total Capital Expenditure		£m	(425)	(830)	0	(849)	99.7%

1) Increase due to NGC's proposed replacement and modification programme.

2) Increased Employee costs relate primarily to recovery of Pension deficit, including that relating to 24Seven staff within Network costs.

3) Increase due to additional investment in the Network.

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	2.1	2.2			
Unplanned Customer Minutes Lost per Connected Customer	mins	43	48	n/a	37	-13.7%
Unplanned Customer interruptions per 100 customers		36	37	n/a	34	-6.3%

REVENUE CHANGES				Base Case	QoS Case	DNO Case
Po increase/(decrease)	2005			15.3%	n/a	16.6%
X increase/(decrease)	2006-2009			0.0%	n/a	0.0%

The costs for 2002/3 actuals and all forecast years have been adjusted to remove margins included in charges from 24Seven, a related-company service provider. Salary Costs included in charges from 24Seven have been reclassified to the Employee Wages line from the Direct Network Costs line.

DNO's STRATEGY & INVESTMENT PLAN

The main objectives of our investment strategy are:

1.To ensure the business can continue to meet its (increasing) legal and regulatory obligations to operate and maintain a safe, environmentally friendly, economical, and co-ordinated distribution network.
2.To deal with a peak workload in the replacement of ageing assets that can be deferred no longer because of the operation and safety concerns arising from their condition.
3.To meet tougher quality of supply targets, to which are attached financial incentives for success and penalties for failure.
4.To meet increasing demand for new network capacity in our home areas, and for new connections to our networks, arising from general load growth and development, and also from government-sponsored embedded generation and regional regeneration programmes.
5.To maintain the efficiency, security, and integrity of our existing networks, while meeting the challenge of competition from embedded distributors.

The key highlights of our investment plan are:

1.An enhanced EHV infrastructure to address the “islanded” nature of many 132kV substations in the London area. Major reinforcement schemes are planned for Bankside and New Cross in south London and for the City of London.
2.Replacement of 132kV switchgear to align with NGT planned replacement work. Major replacement schemes are planned for Barking in east London and Littlebrook in south London.
3.Reinforcement, load transfer, or enhanced cooling schemes in respect of all main substations at risk of P2/5 non-compliance within the DPCR4 period.
4.Significant network development to support government redevelopment areas at Thames Gateway and Stratford in north London.
5.Reconfiguration and reinforcement of the West End and the City of London 11kV networks to restore security to acceptable levels.
6.Fluid and gas filled cable replacement programmes to replace 80km and 25km respectively of poor condition cable by 2010.
7.Replacement (or removal through network reconfiguration) of 35% of 132kV and 70% of 66kV life-expired switchgear. Major schemes are planned for Lodge Road and Hackney.

Summary of forecasts - SPN

FINANCIAL SUMMARY real 2002/03 prices			2000/01-2004/05 Total	Five Year Total 2005/06-2009/10 Base Case	QoS Case	DNO Case	% change DNO Case v Total
Revenue	Price controlled	£m	804	1,101	n/a	1,114	38.6%
	Excluded Services	£m	105	82	n/a	82	-22.1%
	Deminimis	£m	11	-	n/a	-	-100.0%
	Other Income	£m	118	89	n/a	89	-24.5%
Total Revenue		£m	1,038	1,272	-	1,285	23.7%
Operating Costs	Cost of sales	£m	(22)	(17)	(17)	(17)	-21.3%
	Exit Charges (NGC and other)	£m	(88)	(89)	(89)	(89)	1.0%
	Employee Wages	£m	(97)	(212)	(212)	(212)	1) 119.3%
	Direct Network Costs	£m	(106)	(123)	(123)	(123)	2) 15.6%
	Depreciation	£m	(141)	(190)	(193)	(192)	3) 36.5%
	Network Rates	£m	(76)	(75)	(75)	(75)	-2.3%
	Other Costs	£m	(124)	(102)	(102)	(102)	-17.5%
Total Operating Costs		£m	(654)	(807)	(811)	(810)	23.9%
Capital Expenditure	Load Related	£m	(204)	(243)	(243)	(243)	18.7%
	Capital Contributions	£m	132	96	96	96	-27.5%
	Non Load Related	£m	(349)	(492)	(645)	(532)	52.5%
	Non-operational Capex	£m	(35)	(33)	(33)	(37)	3.7%
Total Capital Expenditure		£m	(456)	(671)	(825)	(715)	56.7%

1) Increased Employee costs relate primarily to recovery of Pension deficit.

2) Primarily additional Tree cutting expenditure.

3) Increase due to additional investment in the Network.

QoS PERFORMANCE		2002/03 Total	2009/10 Base Case	QoS Case	DNO Case	% change from 02/03 to 09/10 DNO Case v 02/03
Customers connected	m	2.2	2.3			
Unplanned Customer Minutes Lost per Connected Customer	mins	81	87	84	64	-21.5%
Unplanned Customer interruptions per 100 customers		90	101	98	77	-14.9%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po increase/(decrease)	2005		39.9%	n/a	41.5%
X increase/(decrease)	2006-2009		0.0%	n/a	0.0%

DNO's STRATEGY & INVESTMENT PLAN

The main objectives of our investment strategy are:

1. To ensure the business can continue to meet its (increasing) legal and regulatory obligations to operate and maintain a safe, environmentally friendly, economical, and co-ordinated distribution network.
2. To deal with a peak workload in the replacement of ageing assets that can be deferred no longer because of the operation and safety concerns arising from their condition.
3. To meet tougher quality of supply targets, to which are attached financial incentives for success and penalties for failure.
4. To meet increasing demand for new network capacity in our home areas, and for new connections to our networks, arising from general load growth and development, and also from government-sponsored embedded generation and regional regeneration programmes.
5. To maintain the efficiency, security, and integrity of our existing networks, while meeting the challenge of competition from embedded distributors.

The key highlights of our investment plan are:

1. Establishment of three new switching sites in Kent to reduce risks to SPN's 132kV system following faults on NGC's 400kV DC link with France.
2. A major scheme to replace the 132kV switchgear, and associated civil assets, at Beddington in South London.
3. The replacement of three double circuit gas compression cables: major schemes are planned for the Worthing and Twickenham areas.
4. Reinforcement, load transfer, or enhanced cooling schemes in respect of all main substations at risk of P2/5 non-compliance within the DPCR4 period.
5. Significant network development to support government redevelopment areas at Thames Gateway and to meet increased demands from Network Rail.
6. Some 7% of all primary transformers to be replaced in the DPCR4 period because of condition or to meet reinforcement requirements.
7. Some 27% of LV, and 22% of HV, overhead lines to be refurbished in the period to improve network resilience.
8. Undergrounding of HV overhead lines on mixed urban-rural circuits at a rate of approximately 2% a year.
9. Significantly expanded automation of HV circuits, including the script-driven automatic reconfiguration of networks.

Summary of forecasts - UUE

FINANCIAL SUMMARY			2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
	real 2002/03 prices		Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	1,077.9	1,179.3	1,185.6	1,212.1	12%
	Excluded Services	£m	178.4	121.9	121.9	131.3	-26%
	Deminimis	£m	36.1	-	-	-	-100%
	Other income	£m	96.5	51.6	51.6	51.6	-47%
Total Revenue		£m	1,388.9	1,352.8	1,359.1	1,395.0	0%
Operating Costs	Cost of sales	£m	(82.7)	(29.2)	(29.2)	(29.2)	-65%
	Exit Charges (NGC and other)	£m	(67.9)	(39.2)	(39.2)	(39.2)	-42%
	Employee Wages	£m	(124.3)	(178.0)	(178.0)	(178.6)	44%
	Direct Network Costs	£m	(49.5)	(33.6)	(33.6)	(35.5)	-28%
	Depreciation	£m	(242.8)	(254.3)	(258.4)	(258.6)	7%
	Network Rates	£m	(95.1)	(98.4)	(98.4)	(98.4)	3%
	Other Costs	£m	(66.1)	(117.2)	(118.2)	(119.3)	80%
Total Operating Costs		£m	(728.4)	(749.9)	(755.0)	(758.8)	4%
Capital Expenditure	Load Related	£m	(184.5)	(239.8)	(239.8)	(345.7)	87%
	Capital Contributions	£m	87.2	79.1	79.1	123.3	41%
	Non Load Related	£m	(376.9)	(449.4)	(466.6)	(449.4)	19%
	Non-operational Capex	£m	(49.0)	(32.4)	(32.4)	(32.4)	-34%
Total Capital Expenditure		£m	(523.2)	(642.5)	(659.7)	(704.2)	35%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	2.3	2.4			
Unplanned Customer Minutes Lost	mins	63.4	61.7	56.8	61.7	-3%
Unplanned Customer interruptions per 100 customers		64.9	61.4	54.0	61.4	-5%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		4.1%	4.3%	5.0%
X	2006-2009		4.1%	4.3%	5.0%

DNO's STRATEGY & INVESTMENT PLAN

United Utilities' plans are based on preserving the current high levels of service to customers. This is to be achieved through :

- maintaining the level of network risk and long term security of supply
- a continuing stable fault rate on the network
- ensuring all demands can be met by sustaining an adequate and efficient capacity margin.

Base Case investment of £643m is proposed to maintain service levels to customers, in a scenario with no new distributed generation. This figure increases by £39m (£22m of which is incurred in 2003/4 and 2004/5) to meet the hypothetical targets for the Quality of Supply scenario.

The DNO case includes £106m of investment to support the connection of distributed generation between 2005 and 2010. This has been added to the Base Case plans, which assume no Quality of Supply improvements.

All scenarios have been constructed on a consistent cost basis, recognising that specific account will have to be taken of the impact on our costs of a number of particular areas of uncertainty, such as network rates, traffic management costs, pension liabilities, and corporation tax.

Summary of forecasts - NEDL

FINANCIAL SUMMARY			2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
	real 2002/03 prices		Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	805.1	689.9	696.9	704.1	-13%
	Excluded Services	£m	66.6	46.8	46.8	46.8	-30%
	Deminimis	£m	14.8	21.0	21.0	21.0	41%
	Other income	£m	75.6	73.1	73.1	73.1	-3%
Total Revenue		£m	962.1	830.8	837.8	845.0	-12%
Operating Costs	Cost of sales	£m	1.3	3.7	3.7	3.7	185%
	Exit Charges (NGC and other)	£m	55.0	72.2	72.2	72.2	31%
	Employee Wages	£m	65.6	59.4	59.4	59.4	-9%
	Direct Network Costs	£m	82.2	74.4	77.0	77.9	-5%
	Depreciation	£m	123.4	119.1	119.5	120.8	-2%
	Network Rates	£m	74.2	63.9	63.9	63.9	-14%
	Other Costs	£m	84.3	86.9	86.9	86.9	3%
Total Operating Costs		£m	486.0	479.6	482.6	484.8	0%
Capital Expenditure	Load Related	£m	170.0	175.5	175.5	175.5	3%
	Capital Contributions	£m	(113.7)	(120.2)	(120.2)	(120.2)	6%
	Non Load Related	£m	232.4	247.5	259.0	290.3	25%
	Non-operational Capex	£m	14.9	14.5	14.5	14.5	-3%
Total Capital Expenditure		£m	303.6	317.3	328.8	360.1	19%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	1.5	1.6			
Unplanned Customer Minutes Lost	mins	62.2	74.8	67.7	67.6	9%
Unplanned Customer interruptions per 100 customers		73.9	74.6	69.7	70.6	-4%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		-9.0%	-8.1%	-7.2%
X	2006-2009		1.0%	1.0%	1.0%

DNO's STRATEGY & INVESTMENT PLAN

The base case is sufficient (but no more) to maintain risk and performance at current levels over the period

There is no provision for uncertain issues such as ESQCR, resilience or facilitating DG

The 'QoS case' figures reflect the central improvement scenario specified in the FBPQ

The 'DNO case' figures reflect improvements in headline performance similar to those for the 'QoS case', but instead of relying heavily upon improvements for (better-served) urban customers seek to reduce the performance gap for rural customers

The 'DNO case' also provides for enhancing the infrastructure behind the rural 20 kV system in Durham and Northumberland, to reduce the performance gap between these areas and more common 11 kV networks

Neither 'QoS' nor 'DNO' case figures reflect all the options explored under the FBPQ scenarios, such as resilience or further tightening of multiple interruptions standards: these programmes could cost up to £1bn more, depending on customer requirements

On QoS performance our forecast reflects expectations of typical weather in each year. 2002/03 in particular was a benign period, with significantly lower fault activity than expected in a normal year.

Any recovery of pension deficit is excluded from the above scenario's due to current uncertainty in this area

The X factor change represents an assumption of RPI less 1% for the period 2006 to 2010

No Distributed Generation is included in the above scenario's

Summary of forecasts - YEDL

FINANCIAL SUMMARY			2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
	real 2002/03 prices		Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	1,100.2	981.9	991.2	994.9	-10%
	Excluded Services	£m	66.2	49.2	49.2	49.2	-26%
	Deminimis	£m	12.8	6.5	6.5	6.5	-49%
	Other income	£m	98.4	75.2	75.2	75.2	-24%
Total Revenue		£m	1,277.7	1,112.8	1,122.1	1,125.8	-12%
Operating Costs	Cost of sales	£m	1.3	-	-	-	-100%
	Exit Charges (NGC and other)	£m	87.5	70.4	70.4	70.4	-20%
	Employee Wages	£m	36.7	7.0	7.0	7.0	-81%
	Direct Network Costs	£m	133.1	156.0	159.4	160.2	20%
	Depreciation	£m	178.5	169.4	170.4	170.8	-4%
	Network Rates	£m	113.3	108.0	108.0	108.0	-5%
	Other Costs	£m	117.3	98.1	98.1	98.1	-16%
Total Operating Costs		£m	667.7	608.9	613.3	614.5	-8%
Capital Expenditure	Load Related	£m	250.9	262.7	262.7	262.7	5%
	Capital Contributions	£m	(175.1)	(184.0)	(184.0)	(184.0)	5%
	Non Load Related	£m	300.5	363.2	388.8	398.8	33%
	Non-operational Capex	£m	10.4	-	-	-	-100%
Total Capital Expenditure		£m	386.7	441.9	467.5	477.5	23%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	2.1	2.3			
Unplanned Customer Minutes Lost	mins	64.7	64.5	56.3	55.6	-14%
Unplanned Customer interruptions per 100 customers		62.4	74.5	66.5	67.3	8%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		-9.2%	-8.4%	-8.0%
X	2006-2009		1.0%	1.0%	1.0%

DNO's STRATEGY & INVESTMENT PLAN

There is no provision for uncertain issues such as ESQCR, resilience or facilitating DG

The 'QoS case' figures reflect the central improvement scenario specified in the FBPQ

The 'DNO case' figures reflect improvements in headline performance similar to those for the 'QoS case', but instead of relying heavily upon improvements for (better-served) urban customers seek to reduce the performance gap for rural customers

Neither 'QoS' nor 'DNO' case figures reflect all the options explored under the FBPQ scenarios, such as resilience or further tightening of multiple interruptions standards: these programmes could cost up to £300m more, depending on customer requirements

On QoS performance our forecast reflects expectations of typical weather in each year. 2002/03 in particular was a benign period, with significantly lower fault activity than expected in a normal year

Any recovery of pension deficit is excluded from the above scenario's due to current uncertainty in this area

The X factor change represents an assumption of RPI less 1% for the period 2006 to 2010

No Distributed Generation is included in the above scenario's

Summary of forecasts - WPD South Wales

FINANCIAL SUMMARY			2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
	real 2002/03 prices		Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	672.2	726.9	n/a	753.7	12%
	Excluded Services	£m	79.8	59.5	n/a	45.5	-43%
	Deminimis	£m	6.6	-	n/a	-	-100%
	Other income	£m	90.7	39.4	n/a	26.9	-70%
Total Revenue		£m	849.3	825.8	-	826.1	-3%
Operating Costs	Cost of sales	£m	(20.6)	(19.0)	(19.0)	(4.0)	-81%
	Exit Charges (NGC and other)	£m	(41.7)	(20.4)	(20.4)	(20.4)	-51%
	Employee Wages	£m	(63.9)	(57.5)	(57.5)	(57.5)	-10%
	Direct Network Costs	£m	(83.1)	(58.0)	(57.7)	(64.0)	-23%
	Depreciation	£m	(138.4)	(155.9)	(155.9)	(159.1)	15%
	Network Rates	£m	(60.3)	(64.5)	(64.5)	(64.5)	7%
	Other Costs	£m	(57.7)	(102.3)	(102.3)	(102.3)	77%
Total Operating Costs		£m	(465.7)	(477.6)	(477.3)	(471.8)	1%
Capital Expenditure	Load Related	£m	(101.6)	(103.1)	(103.1)	(144.3)	42%
	Capital Contributions	£m	52.8	51.0	51.0	74.4	41%
	Non Load Related	£m	(181.7)	(165.0)	(204.1)	(217.2)	20%
	Non-operational Capex	£m	(20.6)	(21.4)	(21.4)	(21.4)	4%
Total Capital Expenditure		£m	(251.1)	(238.5)	(277.6)	(308.5)	23%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	1.1	1.1			
* Unplanned Customer Minutes Lost	mins	51.3	72.0	62.2	65.3	27%
* Unplanned Customer interruptions per 100 customers		86.7	115.0	87.8	104.9	21%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		14.0%	n/a	18.2%
X	2006-2009		-1.0%	n/a	-1.0%

DNO's STRATEGY & INVESTMENT PLAN

During the forthcoming period our overall business objective will continue to be the delivery of quality of service excellence through:

- Focused operational management;
- Implementation of leading edge IT systems and processes; and
- Lean support services and corporate structure.

Gross load related capital expenditure is driven by economic activity. In line with economic forecasts, the underlying activity level for the forthcoming period is forecast to be marginally higher that the expected out turn for the current period. In addition our forecast caters for the connection of approximately 250 MW of distributed generation during the forthcoming period.

Non load related capital expenditure is predominantly associated with the replacement of assets that are either in poor condition or are poorly performing (in terms of safety or quality of supply). Forecast non load related capital expenditure for the forthcoming period is lower than the expected out turn for the current period. The reduction is attributable to the completion, in 2004/05, of a 10 year programme to replace a type of suspect 11 kV switchgear.

For our preferred case, we propose to deliver reductions of 6.7 Customer Minutes Lost per Customer (9% reduction) and 10.2 Customers Interrupted per 100 Customers (9% reduction). In order to deliver these reductions we propose to install additional automatic switchgear on the HV overhead network and undertake additional 11 kV overhead line refurbishment.

Our capital expenditure forecast also cater for the impending changes in legislation that are likely to result in the imposition of "lane rental" charges on all utilities when excavation works are carried out in the public highway.

In order to improve the resilience of the overhead distribution network during severe weather conditions we propose to implement a three year tree cutting cycle instead of the existing five year cycle.

*** 2002/03 CI's and CML exclude impact of the October 2002 storm.**

Summary of forecasts - WPD South West

FINANCIAL SUMMARY		real 2002/03 prices	2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
			Total	**Base Case**	**QoS Case**	**DNO Case**	**DNO Case v Total**
Revenue	Price controlled	£m	885.9	973.7	n/a	999.7	13%
	Excluded Services	£m	64.0	49.0	n/a	48.3	-25%
	Deminimis	£m	30.3	21.5	n/a	21.5	-29%
	Other income	£m	128.5	54.1	n/a	33.6	-74%
Total Revenue		£m	1,108.7	1,098.3	-	1,103.1	-1%
Operating Costs	Cost of sales	£m	(41.2)	(41.5)	(41.5)	(21.0)	-49%
	Exit Charges (NGC and other)	£m	(42.6)	(24.9)	(24.9)	(24.9)	-42%
	Employee Wages	£m	(114.6)	(115.1)	(115.1)	(115.1)	0%
	Direct Network Costs	£m	(72.4)	(72.5)	(72.5)	(77.0)	6%
	Depreciation	£m	(166.0)	(205.0)	(205.0)	(208.8)	26%
	Network Rates	£m	(80.7)	(85.1)	(85.1)	(85.1)	5%
	Other Costs	£m	(0.9)	(103.4)	(103.4)	(107.4)	11833%
Total Operating Costs		£m	(518.4)	(647.5)	(647.5)	(639.3)	23%
Capital Expenditure	Load Related	£m	(149.8)	(154.0)	(154.0)	(194.3)	30%
	Capital Contributions	£m	78.4	79.5	79.5	104.7	34%
	Non Load Related	£m	(244.3)	(303.1)	(318.4)	(354.4)	45%
	Non-operational Capex	£m	(43.6)	(43.7)	(43.7)	(43.7)	0%
Total Capital Expenditure		£m	(359.3)	(421.3)	(436.6)	(487.7)	36%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	**Base Case**	**QoS Case**	**DNO Case**	**DNO Case v 02/03**
Customers connected	m	1.4	1.6			
* Unplanned Customer Minutes Lost	mins	51.2	60.7	60.7	60.2	18%
* Unplanned Customer interruptions per 100 customers		78.1	85.6	84.9	84.9	9%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		13.0%	n/a	16.0%
X	2006-2009		-1.0%	n/a	-1.0%

DNO's STRATEGY & INVESTMENT PLAN

During the forthcoming period our overall business objective will continue to be the delivery of quality of service excellence through:

· Focused operational management;

· Implementation of leading edge IT systems and processes; and

· Lean support services and corporate structure.

Gross load related capital expenditure is driven by economic activity. In line with economic forecasts, the underlying activity level for the forthcoming period is forecast to be marginally higher that the expected out turn for the current period. In addition our forecast caters for the connection of approximately 190 MW of distributed generation during the forthcoming period.

Non load related capital expenditure is predominantly associated with the replacement of assets that are either in poor condition or are poorly performing (in terms of safety or quality of supply). Forecast non load related capital expenditure for the forthcoming period is higher than the expected out turn for the current period. The increase is attributable to the need to carry out remedial works on open wire LV overhead lines that are in close proximity to buildings and the general ageing of the distribution network assets.

For our preferred case, we propose to deliver reductions of 0.5 Customer Minutes Lost per Customer (0.8% reduction) and 0.7 Customers Interrupted per 100 Customers (0.8% reduction). In order to deliver these reductions we propose to undertake additional 11 kV overhead line refurbishment.

Our capital expenditure forecast also cater for the impending changes in legislation that are likely to result in the imposition of "lane rental" charges on all utilities when excavation works are carried out in the public highway.

In order to improve the resilience of the overhead distribution network during severe weather conditions we propose to implement a three year tree cutting cycle instead of the existing five year cycle.

*** 2002/03 CI's and CML exclude impact of the October 2002 storm.**

Summary of forecasts - SP Manweb

FINANCIAL SUMMARY	real 2002/03 prices		2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
			Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	798.0	883.6	n/a	883.6	10.7%
	Excluded Services	£m	113.5	90.9	n/a	90.9	-19.9%
	Deminimis	£m	1.1	-	n/a	-	-100.0%
	Other Income	£m	96.6	86.5	n/a	86.5	
Total Revenue		£m	1,009.3	1,061.0	-	1,061.0	-3.5%
Operating Costs	Cost of sales	£m	(52.6)	(41.6)	n/a	(41.6)	-20.9%
	NGC Exit Charges	£m	(78.3)	(72.0)	n/a	(72.0)	-8.0%
	Employee Wages	£m	(21.1)	(2.5)	n/a	(2.5)	-88.1%
	Direct Network Costs	£m	(160.3)	(161.6)	n/a	(162.4)	1.3%
	Depreciation	£m	(111.3)	(145.3)	n/a	(145.3)	30.5%
	Network Rates	£m	(75.1)	(75.0)	n/a	(75.0)	-0.2%
	Other Costs	£m	(56.6)	(42.0)	n/a	(42.0)	-25.8%
Total Operating Costs		£m	(555.3)	(540.0)	-	(540.8)	-2.6%
Capital Expenditure	Load Related	£m	(227.5)	(202.4)	n/a	(202.4)	-11.0%
	Capital Contributions	£m	71.1	24.2	n/a	24.2	-66.0%
	Non Load Related	£m	(264.0)	(420.2)	n/a	(437.6)	65.7%
	Non-operational Capex	£m	(5.0)		n/a	-	
Total Capital Expenditure		£m	(425.4)	(598.4)	-	(615.8)	46.5%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	1.4	1.5			
Unplanned Customer Minutes Lost	mins	103.8	49.8	0.0	49.4	-52.4%
Unplanned Customer interruptions per 100 customers		47.3	45.8	0.0	45.4	-4.0%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		-8.8%	n/a	n/a
X	2006-2009		0.0%	n/a	n/a

DNO's STRATEGY & INVESTMENT PLAN

SP Manweb will continue to manage its distribution network to be sustainable in the long-term. This will ensure that our customers continue to receive reliable electricity supplies, efficiently managed and resilient to severe weather events. The plans that we have recommended to Ofgem for the period 2005-2010 are the next stage of our longer-term plans to ensure that we meet these commitments to our customers

In compiling these plans we have recognised that this distribution price control review is different from previous reviews due to increasing costs in a number of areas, including network safety, security and reliability and distributed generation. These cost increases result in an upward pressure on prices.

Our plans are based on advanced asset risk management policies and practices and take account of the increased levels of asset replacement required to manage the risks associated with the ageing asset base. These plans are comprised of a number of components:

- the Base Case, as specified by Ofgem, to maintain current levels of asset fault rates, network performance and safety;
- the Quality of Supply Case, to improve overall network performance in line with Ofgem's specified targets;
- the SP Manweb Case, incorporating the Base Case, the Quality of Supply Case and additional expenditure to improve the quality of supply to 'worst served' customers and address the issue of distribution losses; and
- the Distributed Generation (DG) Case, setting out the expenditure necessary to accommodate significantly increased levels of renewable generation in the SP Manweb area.

Ofgem has specified a quality of supply scenario that requires DNOs to achieve a benchmark level of performance by 2020 with an interim target for 2010. SP Manweb has one of the best performing distribution networks in the country and is the only company that is already outperforming the 2020 benchmark targets. No incremental expenditure over and above the Base Case is therefore required. However the levels of expenditure specified in our Base Case are required to prevent any deterioration in the quality of supply experienced by our customers.

Over the five-year period the plans that we have recommended to Ofgem, consisting of the SP Manweb Case plus the DG Case, require the following:

- operating expenditure of £549m (£541m from the SP Manweb Case and £8m from the DG Case); and
- net capital investment of £691m (£616m from the SP Manweb Case and £75m from the DG Case).

It is extremely important that the allowed cost of capital is set at a level that provides a sufficient and stable return on investment and enables companies to attract and retain equity funding. A cost of capital of between 7% and 8% (pre-tax real) is strongly supported by market evidence and authoritative academic studies.

Summary of forecasts - SP Distribution

FINANCIAL SUMMARY			2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
	real 2002/03 prices		Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	1,332.0	1,380.2		1,380.2	3.6%
	Excluded Services	£m	75.6	49.9		49.9	-34.0%
	Deminimis	£m	25.2	-		-	-100.0%
			285.5	274.5		274.5	-3.8%
Total Revenue		£m	1,718.3	1,704.6	-	1,704.6	-0.8%
Operating Costs	Cost of sales	£m	(56.5)	(48.1)		(48.1)	-14.9%
	NGC Exit Charges	£m	(256.0)	(255.0)		(255.0)	-0.4%
	Employee Wages	£m	(27.5)	(2.5)		(2.5)	-90.9%
	Direct Network Costs	£m	(146.4)	(143.5)	(4.0)	(148.9)	1.7%
	Depreciation	£m	(177.7)	(188.4)		(188.4)	6.0%
	Network Rates	£m	(102.7)	(123.5)		(123.5)	20.3%
	Other Costs	£m	(75.2)	(46.0)		(46.0)	-38.8%
Total Operating Costs		£m	(842.0)	(807.0)	(4.0)	(812.4)	-3.5%
Capital Expenditure	Load Related	£m	(267.7)	(268.8)		(268.8)	0.4%
	Capital Contributions	£m	114.6	90.2		90.2	-21.3%
	Non Load Related	£m	(326.2)	(426.3)	(29.0)	(474.4)	45.5%
	Non-operational Capex	£m	(11.6)	-		-	-100.0%
Total Capital Expenditure		£m	(490.9)	(604.9)	(29.0)	(653.0)	33.0%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	1.9	2.1			
Unplanned Customer Minutes Lost	mins	66.3	68.0	(10.5)	57.3	-14%
Unplanned Customer interruptions per 100 customers		61.7	61.1	(1.9)	59.0	-4%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		-2.5%		
X	2006-2009		0.0%		

DNO's STRATEGY & INVESTMENT PLAN

SP Distribution will continue to manage its distribution network to be sustainable in the long-term. This will ensure that our customers continue to receive reliable electricity supplies, efficiently managed and resilient to severe weather events. The plans that we have recommended to Ofgem for the period 2005-2010 are the next stage of our longer-term plans to ensure that we meet these commitments to our customers

In compiling these plans we have recognised that this distribution price control review is different from previous reviews due to increasing costs in a number of areas, including network safety, security and reliability and distributed generation. These cost increases result in an upward pressure on prices.

Our plans are based on advanced asset risk management policies and practices and take account of the increased levels of asset replacement required to manage the risks associated with the ageing asset base. These plans are comprised of a number of components:

- the Base Case, as specified by Ofgem, to maintain current levels of asset fault rates, network performance and safety;
- the Quality of Supply Case, to improve overall network performance in line with Ofgem's specified targets;
- the SP Distribution Case, incorporating the Base Case, the Quality of Supply Case and additional expenditure to improve the quality of supply to 'worst served' customers and address the issue of distribution losses; and
- the Distributed Generation (DG) Case, setting out the expenditure necessary to accommodate significantly increased levels of renewable generation in the SP Distribution area.

Over the five-year period the plans that we have recommended to Ofgem, consisting of the SP Distribution Case plus the DG Case, require the following:

- operating expenditure of £821m (£812m from the SP Distribution Case and £8m from the DG Case); and
- net capital investment of £731m (£653m from the SP Distribution Case and £78m from the DG Case).

It is extremely important that the allowed cost of capital is set at a level that provides a sufficient and stable return on investment and enables companies to attract and retain equity funding. A cost of capital of between 7% and 8% (pre-tax real) is strongly supported by market evidence and authoritative academic studies.

Summary of forecasts - Scottish Hydro-Electric Power Distribution

FINANCIAL SUMMARY	real 2002/03 prices		2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
			Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	785.5	842.1			
	Excluded Services	£m	37.2	37.5			
	Deminimis	£m	1.4	1.0			
	Other income	£m	66.2	52.5			
Total Revenue		£m	890.3	933.1	n/a	n/a	
Operating Costs	Cost of sales	£m	10.4	10.5	10.5	10.5	1%
	Exit Charges (NGC and other)	£m	41.3	52.5	52.5	52.5	27%
	Employee Wages	£m	79.3	85.6	85.6	85.6	8%
	Direct Network Costs	£m	46.4	47.8	47.8	47.8	3%
	Depreciation	£m	156.2	148.5	148.5	148.5	-5%
	Network Rates	£m	42.3	41.5	41.5	41.5	-2%
	Other Costs	£m	66.4	67.0	67.0	67.0	1%
Total Operating Costs		£m	442.3	453.4	453.4	453.4	3%
Capital Expenditure	Net Load related	£m	66.8	54.3			
	Non Load Related	£m	129.5	183.9			
	Non-operational Capex	£m	1.8	2.0			
Total Capital Expenditure		£m	198.1	240.2	244.2	272.1	37%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	0.681	0.733			
Unplanned Customer Minutes Lost	mins	71.3	99.1	96.4	93.9	32%
Unplanned Customer interruptions per 100 customers		85.5	97.1	95.8	95.4	12%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		4.5	n/a	n/a
X	2006-2009		1.4	n/a	n/a

DNO's STRATEGY & INVESTMENT PLAN

The forecasts above continue the focus on efficiency and performance.

The main upward pressures on opex recognised in the Business Plan are:

- expected significant increase in pension contributions;
- pressure on salaries;
- increased frequency and costs of tree cutting;
- increased costs of responding to and insuring against severe weather;
- increased maintenance costs under the Electricity, Safety, Quality and Continuity Regulations (2002).

Our proposed capex programme will produce improved customer service and provide good stewardship of assets while representing value for money. The main initiatives will:

- enhance network resilience
- address ageing assets;
- produce 5% reduction in Customer Minutes Lost.

Forecasts above do not include Distributed Generation, IFIs or RPZs.
Exit charges and business rates are assumed to continue as pass-through.
Metering remains included.
Forecasts assume 20 year regulatory depreciation.

There are potentially significant costs which have not been included at this stage, these include Lane Rentals.
atypical items, the costs of regulatory IT changes arising from reform of competitive markets,
and costs associated with BETTA e.g. SESL and diesel generation on Shetland.

Summary of forecasts - Southern Electric

FINANCIAL SUMMARY		real 2002/03 prices	2000/01-2004/05	Five Year Total 2005/06-2009/10			% change
			Total	Base Case	QoS Case	DNO Case	DNO Case v Total
Revenue	Price controlled	£m	1,544.6	1,653.5			
	Excluded Services	£m	135.5	135.0			
	Deminimis	£m	-	-			
	Other income	£m	142.5	103.0			
Total Revenue		£m	1,822.6	1,891.5	n/a	n/a	
Operating Costs	Cost of sales	£m	38.1	38.0	38.0	38.0	0%
	Exit Charges (NGC and other)	£m	109.3	103.0	103.0	103.0	-6%
	Employee Wages	£m	162.3	209.3	209.3	209.3	29%
	Direct Network Costs	£m	85.4	93.4	93.4	93.4	9%
	Depreciation	£m	265.9	302.1	302.1	302.1	14%
	Network Rates	£m	166.2	170.5	170.5	170.5	3%
	Other Costs	£m	65.7	52.5	52.5	52.5	-20%
Total Operating Costs		£m	892.9	968.8	968.8	968.8	9%
Capital Expenditure	Net Load Related	£m	208.3	206.5			
	Non Load Related	£m	278.7	387.9			
	Non-operational Capex	£m	2.1	5.0			
Total Capital Expenditure		£m	489.1	599.4	740.4	653.5	34%

QoS PERFORMANCE		2002/03	2009/10			% change from 02/03 to 09/10
		Total	Base Case	QoS Case	DNO Case	DNO Case v 02/03
Customers connected	m	2.736	2.931			
Unplanned Customer Minutes Lost	mins	101.7	85.0	74.0	79.0	-22%
Unplanned Customer interruptions per 100 customers		98.5	90.0	83.6	86.5	-12%

REVENUE CHANGES			Base Case	QoS Case	DNO Case
Po	2005		3.0	n/a	n/a
X	2006-2009		1.4	n/a	n/a

DNO's STRATEGY & INVESTMENT PLAN

The forecasts above continue the focus on efficiency and performance.

The main upward pressures on opex recognised in the Business Plan are:
- expected significant increase in pension contributions;
- pressure on salaries;
- increased frequency and costs of tree cutting;
- increased costs of responding to and insuring against severe weather;
- increased maintenance costs under the Electricity, Safety, Quality and Continuity Regulations (2002).

Our proposed capex programme will produce improved customer service and provide good stewardship of assets while representing value for money. The main initiatives will:
- enhance resilience;
- address ageing assets;
- address legacy issue of Consac cable in a proactive manner;
- produce a 7% reduction in Customer Minutes Lost.

Forecasts above do not include Distributed Generation, IFIs or RPZs.
Exit charges and business rates are assumed to continue as pass-through.
Metering remains included.
Forecasts assume 20 year regulatory depreciation.

There are potentially significant costs which have not been included at this stage, these include Lane Rentals. atypical items, and the costs of regulatory IT changes arising from reform of competitive market systems.

Appendix 6 Registration of interest for public workshop

Ofgem is holding a public workshop on key issues arising from the price control review on 20 April in London. Key topics to be covered include:

- companies' cost forecasts;
- financial issues; and
- quality of supply.

Ofgem intends that the workshop will combine presentations and breakout sessions where issues can be discussed in more detail.

Please complete and return this form by 1 April 2004 to:

Paul O'Donovan
Ofgem
9 Millbank
London, SW1P 3GE

After the closing date, further details about the workshop, including booking forms, will be sent to all those who have registered an interest in attending. If you have any queries, please contact Paul O'Donovan on 020 7901 7414 or at Paul.ODonovan@ofgem.gov.uk

Registration of interest for public workshop

Company/Organisation	
Company/Organisation **Address**	

Name of attendee	**Phone number**

E-mail address

Please indicate preference for breakout session:			