Promoting choice and value
for all gas and electricity customers

Electricity Distribution Price Control Review Policy Paper

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Target audience: Consumers and their representatives, distribution network operators (DNOs), independent distribution network operators (IDNOs), owners and operators of distributed energy schemes, transmission owners, generators, electricity suppliers and any other interested parties.

Overview: Ofgem regulates the 14 DNOs, who are all regional monopolies to protect the interests of current and future consumers. We set a price control every five years. This sets the total revenues that each DNO can collect from customers at a level that allows an efficient business to finance their activities. We also place incentives on DNOs to innovate and find more efficient ways to provide an appropriate level of network capacity, security, reliability and quality of service.

The current price control expires on 31 March 2010 and Ofgem is now undertaking a Distribution Price Control Review (DPCR5) to set the controls for 2010-2015. This is the second document in the review. We have set out for consultation our views on the overall approach to setting the new control, the methodologies we propose to use, the structure of incentives and the new regulatory arrangements that we think are appropriate. One of the key themes for this review is to ensure that the price control allows the DNOs to play a full role in tackling climate change. This is the last broad ranging consultation before we publish our initial proposals on each company's revenue requirements in the summer of 2009.

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Context

In March 2008 we published our initial consultation document for the distribution price control review (DPCR5). The document focussed on three key themes, the environment, customers and networks. Since March it has become even clearer that climate change will be a significant and important factor for DPCR5. The Energy Act 2008, Climate Change Act 2008 and the Planning and Energy Act 2008 are all now on the statute book and serve to reinforce the Government's commitment to meeting targets for carbon reduction.

Following the publication of the initial consultation document we have published our annual connections industry review which raised a number of issues regarding the level and effectiveness of competition in connections and the service received by customers seeking an electricity connection. We have also been working to move the industry towards more cost reflective tariffs, that amongst other things, reward distributed generation that provides a network benefit through deferring the need for further network investment. In addition, we have published our final Long-term Energy Network Scenarios (LENS) report that sets out a range of plausible electricity network scenarios for Great Britain for 2050 and suggests that the move to a low carbon economy could have profound implications for our energy networks.

In August 2008 the DNOs submitted their initial business plans for the DPCR5 period which suggest the industry is looking for a substantial increase in revenues. We have reviewed these plans and visited each of the DNOs in order to understand the basis of the regulatory reporting pack (RRP) data submitted for 2007-08. We will publish our annual RRP report and our quality of service report in December 2008.

This review is taking place against a background of an economic downturn and great uncertainty particularly in the financial markets. This is not an immediate issue but we are aware that as we firm up our proposals during 2009 we will need to take account of these issues and any further developments.

Associated Documents

- Update letter on the DPCR5 process (151/08)
- Electricity distribution price control review. Initial consultation document (32/08)
- DPCR5 - looking ahead - an initial consultation letter (119/07)
- Consumer First Research for DPCR5 - Quantitative Findings (106/08)
- Connections industry review 2007-08 (143/08)
- Long-term Electricity Network Scenarios (LENS) - final report (157/08)

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Summary

We have three key objectives for DPCR5. Our first is to encourage DNOs to play a fuller role in helping to tackle climate change, both directly through managing their own carbon footprint and indirectly by facilitating new uses of the networks that may occur as we aim to move to a low carbon economy. Another important objective relates to customers where we are looking to make sure that all DNOs pay more attention to all aspects of customer service. These include the service provided by their call centres, the speed and cost of new connections as well as the extent of any interruptions to customers' supply. Finally, we want DNOs to invest efficiently so that they provide secure and reliable supply at the lowest possible cost. But we also want DNOs to do all they can to make sure that any new assets they are installing will meet customers' needs in the future and take account of how those needs might change.

DPCR5 will have been a success if the regulatory settlement provides reasonable rewards for delivering these objectives, and if those DNOs that have performed the best (in terms of outputs and efficiency) earn the highest returns. We have developed a new measure, based on the return on regulatory equity, to assess company performance under the existing price control and how well the various incentives are working. This measure will help us as we calibrate the incentives that will form the next settlement. It should also help us avoid a narrow focus on the weighted average cost of capital when assessing whether the price control package represents a fair balance of risk and reward between customers and shareholders.

In DPCR5, in return for the revenues they collect, we will require each DNO to deliver a predefined set of outputs in a sustainable manner whilst continuing to meet all of their statutory and licence obligations. If any DNO considers the price control package will not deliver them sufficient revenues to meet the agreed outputs and their obligations, they can reject our proposals and we will recommend that the Authority refers the proposed settlement to the Competition Commission. Where a DNO is unable to define a suitable range of measurable outputs we may have to consider a more intrusive regulatory approach to ensure that the settlement does not create opportunities for it to earn returns that are not justified by the service it delivers to customers.

Defining clearer outputs as part of the DPCR5 settlement will provide a better understanding between DNOs, Ofgem and customers about what the DNOs are being paid to deliver. The DNOs are planning a significant increase in their capital investment programmes for the next control period. We will be challenging the DNOs very hard on their cost forecasts. However, it is likely that customers will see an increase in their distribution charges from 2010. Against a background of high energy bills it is important that the regulatory settlement is clear about what customers will get in return for these price increases. We will also make sure that there are strong incentives on DNOs to find ways of delivering the agreed outputs more efficiently, to improve customer service and network reliability.

This review occurs in a period of considerable uncertainty: in the capital markets; in labour markets; in markets that drive the price of equipment DNOs buy; and in the broader economy which could impact on electricity load growth. There is further uncertainty in how and when network use will respond to a range of environment-related initiatives such as smart meters and feed-in tariffs for local generation. We

set out some initial ideas for dealing with this uncertainty and for ensuring that risk is properly allocated between customers and the DNOs while maintaining the incentive on DNOs to look for further (or new) efficiencies. Uncertainty about what sort of network will be needed for a low carbon economy may require DNOs to think carefully about the discretionary replacement of assets which could become redundant as circumstances change. We will review the DNO investment plans in this light.

We have looked to encourage the DNOs to make an immediate contribution to the climate change agenda by reducing electricity lost on the distribution networks and providing better information to local generators that want to connect. But the greater challenge is to find ways of encouraging the DNOs to use the next period to get ready for the low carbon economy, so that they do not hold up the pace of change. We would like to see more evidence of DNOs trialling new technology and experimenting with new commercial arrangements that might be required in the future. We have proposed improved incentives to achieve this. Over the 2010 to 2015 period we would expect DNOs to keep their plans under review to make sure that they are investing in the right equipment and that the networks can adapt to changing needs. The price control needs to provide sufficient flexibility to allow the DNOs to do this.

DNOs should not forfeit quality of service in the quest for greater efficiency and profits. We are keen to introduce a broad measure of customer satisfaction against which DNO performance can be measured and to provide DNOs with an allowance to improve the service received by worst served customers on their network. Many customers continue to receive a poor connections service from their DNO and our recent review shows that while greater competition could help, it has been slow to develop and is still not adequately protecting customers. We set out proposals to address this including further regulation of service standards and changing the way we regulate those parts of the market where competition is emerging. If, having allowed a period of time for competition to develop, there is little sign of progress we may recommend to the Authority that they refer the market segment to the Competition Commission for review.

The turmoil in financial markets and associated economic downturn makes it difficult for Ofgem and the DNOs to forecast key elements of the price control, including financing costs. We have an open mind as to whether we should depart from our traditional fixed ex ante assessment of the cost of capital. We will provide an indicative range of the allowed return on capital in the summer of next year, and will look at this element of the settlement along with the incentives that can impact on shareholder returns. In parallel with this review we are seeking further information from DNOs to demonstrate that their pension costs meet our existing pension principles and are economic and efficient. We will report separately on this work.

We are working with a group of consumer experts and representatives whose role it is to act as a 'critical friend' throughout the review. Their input has been invaluable in framing the proposals in this document.

Responses to this document should be sent by 13 February 2009. We will hold a series of seminars in January 2009 to assist those aiming to respond. In the summer we will publish our initial proposals for the price control settlement.

1. Introduction and Overview

Chapter summary

This chapter sets out: the background to the price control review, the lessons we are learning from the current control, and contains an overview of the policy proposals set out in this document. Before explaining the process for the remainder of the review, we explain the interaction between this project and Ofgem's review of network regulation - the RPI-X@20 project.

Question 1: Do you agree with our assessment of how the DPCR4 settlement has performed in practice?
Question 2: Do you agree with the main lessons we have drawn from this assessment?
Question 3: Have we identified appropriate measures to address our concerns and deliver a settlement that provides better rewards/penalties for highly performing/poorly performing companies?
Question 4: Do you think our proposal to base DNOs' incentives for under/outperformance around their effective return on equity is appropriate?
Question 5: If you do, what range of return on equity do you think would represent a fair balance between customers' and shareholders' interests to reward increased efficiency, better service and innovation, whilst maintaining strong incentives for shareholders of any poorly performing DNOs to improve performance?

Introduction

1.1. Electricity distribution costs account for around £3.6 billion annually and make up around 14 per cent of domestic customers' electricity bills. For a typical electricity domestic customer the distribution element of their annual bill would be approximately £63.

1.2. The 14 DNOs are regional monopolies. We set the total revenues that DNOs can collect from customers so that they are sufficient to run and finance an efficient business and deliver the required outputs. We place incentives on DNOs to innovate and find new ways to improve their efficiency and quality of service. This is achieved through a price control. As the current price control expires on 31 March 2010, Ofgem is undertaking DPCR5 to set the controls for 2010-2015.

1.3. This document is the second consultation of DPCR5. The initial consultation document[1] was published in March 2008 and set out our initial thoughts on the issues that we have to address, the methodologies we might use to set revenues and

[1] Electricity distribution price control review Initial consultation document (32/08)

the process we intend to follow. The initial consultation document outlined three key objectives for DPCR5:

- **Environment:** encouraging DNOs to play a fuller role in helping to tackle climate change, both directly through managing their own carbon footprint and indirectly by facilitating new uses of the networks that are likely to arise as we aim to move to a low carbon economy,

- **Customers:** encouraging all DNOs to pay more attention to all aspects of customer service. These include the quality of service provided by their call centres, the speed and cost of new connections as well as the number and length of any interruptions to customers' supply, and

- **Networks:** encouraging DNOs to invest efficiently, so that they provide secure and reliable supply at the lowest possible cost while ensuring that any new assets that they install meet customers' needs into the future and, where possible, take into account how those needs might change.

1.4. We received positive feedback to our initial consultation document[2] and support for the use of the three key objectives. We intend to maintain the focus on these objectives for the duration of DPCR5.

1.5. This document is the second consultation. In it we set out our views on the overall approach to setting the new control, the methodologies we propose to use, the structure of the incentives and the new regulatory arrangements that we think are appropriate. This is the last broad ranging consultation before we publish our initial proposals on each DNO's revenue requirements in the summer of 2009.

1.6. This document has two parts:

- **Part 1** provides an overview of each of the key themes for DPCR5 and summarises our proposals for key policy areas. It is intended that part 1 be accessible to a wide range of stakeholders.

- **Part 2** contains more detail on the proposals, particularly examining more technical or mechanistic issues. It is particularly aimed at DNOs and interested parties who wish to comment in detail on our proposals. It includes initial impact assessments where we are proposing specific new incentives.

1.7. After an overview of the document and the key issues in this chapter, part 1 of the document focuses on the three key objectives, examines relevant financial issues and outlines the process for DPCR5 in detail. It is structured as follows:

[2] Appendix 5. Summary of responses to the initial consultation document.

- **Environment – chapter 2.** This chapter details the main environmental issues that we are considering as part of DPCR5. These issues cover the role that the DNOs can play in facilitating activities that have a positive impact on the environment and also consider the actions that DNOs can take in reducing their own carbon footprint.

- **Customers – chapter 3.** This chapter sets out the main customer issues and areas that we want DNOs to focus on during DPCR5. We propose to develop a number of existing mechanisms and to introduce a number of new initiatives to facilitate and encourage DNOs to respond better to their customers' needs.

- **Networks – chapter 4.** This chapter sets out further details on our approach to setting the price control for DPCR5 including behaviours we are seeking to encourage. We discuss DNOs' performance during the DPCR4 period and their costs forecasts for DPCR5 and the issues arising from this. We outline potential changes with regards to the cost incentives and to place greater weight on network output measures. We also discuss our latest thinking on the methodology for cost assessment.

- **Financial issues – chapter 5.** This chapter considers our approach to calculating the cost of capital and regulatory asset values, financeability, financial modelling, the treatment of taxation and pensions.

- **Process - chapter 6.** This chapter outlines the proposed content and dates for our key publications and provides an update on our proposed process. It explains how we have consulted with key stakeholders including DNOs and the new consumer challenge group. The chapter also summarises the key findings from the lessons learnt exercise for the gas distribution price control review and explains how we propose to address these for DPCR5.

1.8. Part 2 of the document is comprised of the following appendices:

- **Appendix 1 –** Provides a list of the questions asked throughout this document
- **Appendix 2 –** Outlines the Authority's powers and duties
- **Appendix 3 –** Contains a glossary
- **Appendix 4 –** Provides instructions on how to give feedback on this document

1.9. The following appendices are available in the separate document (159a/08):

- **Appendix 5 –** Summary of responses to our March 2008 initial consultation document
- **Appendix 6 –** Further detail on our proposals for environmental issues
- **Appendix 7 –** Further detail on our proposals for customers
- **Appendix 8 –** Further detail on the cost assessment methodology
- **Appendix 9 -** Further detail regarding the information quality incentive (IQI)
- **Appendix 10 -** Further detail on pensions
- **Appendix 11 -** Further details of the methodology used to calculate return on regulatory equity

- **Appendix 12 -** Summary of the stakeholder engagement undertaken by each DNO
- **Appendix 13 -** Further detail of the Consumer Challenge Group
- **Appendix 14 -** Initial impact assessment on our proposals for distributed generation (DG) connected pre-2005
- **Appendix 15 -** Initial impact assessment on our proposals for innovation
- **Appendix 16** - Initial impact assessment on our proposals to help worst served customers
- **Appendix 17 -** DNO forecast cost information

Background to DPCR5

1.10. The DNOs have legal duties to maintain and develop economic, efficient and co-ordinated distribution networks. This includes responsibility for ensuring that consumers can get a reliable electricity supply, restoring power promptly in the event of an interruption to supply and connecting new customers and local generators to their network quickly and efficiently. These and other responsibilities are set out in the DNOs' licences, the Electricity Act 1989 (as amended) and the Utilities Act 2000.

1.11. There are 14 distribution licence areas in Great Britain shown in the figure 1.1 below. Following privatisation and a number of mergers and acquisitions, the 14 licences are now held by seven companies: EDF Energy (EDFE), CE Electric (CE), E.ON Central Networks (CN), Western Power Distribution (WPD), Scottish and Southern Energy (SSE), ScottishPower (SP) and Electricity North West (ENW).

1.12. There are currently five licensed independent distribution network operators (IDNOs) in GB[3]. We regulate IDNOs using a relative price control and so they are not formally part of this review, although some aspects of our proposals such as any changes to the standards of performance arrangements will also apply to them.

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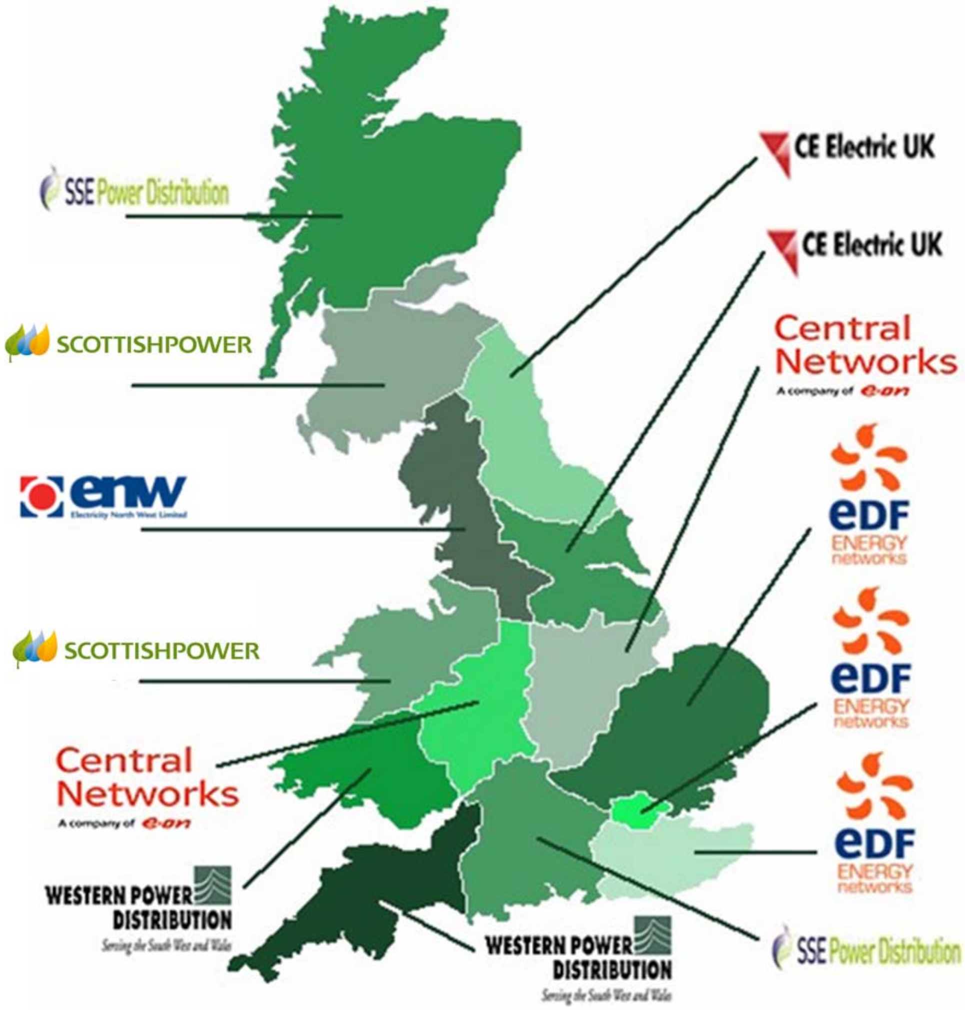
The five licensed IDNOs are Independent Power Networks Limited, The Electricity Network Company Ltd, Energetics Electricity Limited, ESP Networks Limited and ECG Distribution Limited. IDNOs do not have a distribution services area and operate on a national basis.

Figure 1.1 - Map of GB electricity distribution licence areas



1.13. Ofgem regulates the revenues earned by the DNOs through a price control which is currently set every five years. We do this by applying incentive regulation. This involves setting each DNO a base revenue allowance sufficient to cover efficient investment, operating costs and an appropriate return on historical investments whilst delivering required outputs. If the company manages to invest and operate at lower cost whilst delivering the required outputs and customer service it will be able to increase the rate of return it earns. If costs are higher and/or service or outputs fall it will earn less than the allowed rate of return. The control therefore provides a strong efficiency incentive on DNOs.

1.14. DNOs may also earn more (or less) than the base revenue allowance depending on how they perform against a number of additional incentives in the control. For example, DNOs earn financial rewards (or penalties) according to: the number and duration of interruptions there are each year and their performance relative to a target for electricity lost when transporting electricity across their distribution network.

1.15. DNO revenues from connection activities are not directly subject to the price control mechanism, although DNOs' connections margins are removed through the way their asset base (the regulatory asset value (RAV)) is updated. Ofgem does, however, have the power to determine disputes between customers and DNOs over connection charges.

1.16. DNOs metering activities have, since the start of DPCR4, been subject to a separate price control. Ofgem recently reviewed this control and in 2007 we lifted the price cap on new and replacement electricity meters following a review of competition in this market. Government policy is for smart meters to be delivered to all homes after a 10 year roll out period. We expect a decision from Government soon on the arrangements for this roll out. It is possible that some of the gas and electricity meters currently installed will be replaced by a smart meter before the cost of the asset has been fully amortised. Ofgem is working with Government on this matter. While some DNOs have suggested we should look to compensate them for any impact of smart metering roll out through DPCR5 it is too early to say whether this is appropriate or necessary.

Charging methodologies

1.17. DNOs' charging methodologies determine how these allowed revenues are recovered from different customer groups. DNOs have to submit their methodologies to Ofgem and we can veto their proposals if we think they do not meet defined objectives set out in their licences. These objectives include that charges reflect the costs that different customers impose on the network and are transparent.

1.18. For several years now we have been working with DNOs to encourage them to adopt better charging methodologies in time for the commencement of the next price control period. Most recently this has involved Ofgem proposing a collective licence modification that would result in all DNOs applying the same cost reflective charging methodology which would be subject to an open governance process allowing all users to bring forward modifications. Although five of the seven DNOs accepted our proposals (SSE and SP rejected the proposals) we did not receive the necessary level of support to implement the new licence conditions. We will shortly consult on the way forward but we are minded to refer this matter to the Competition Commission unless suppliers, generators and customers who pay the charges and are most directly affected by them tell us that this is not a sufficiently high priority matter to address now or there are other workable solutions.

1.19. Whichever route we take it is now apparent that we will not have the charging arrangements we hoped for in time for the start of DPCR5. We have concerns that at least some of the investment proposed for the next price control period could be avoided if charging methodologies encouraged reductions in peak demand through energy management/efficiency and discouraged new customers who have some flexibility over their location (such as data centres) from locating in 'hotspots' where capacity is tight - or better rewarded distributed generators for relieving those local constraints. In the absence of progress on the structure of charges project we will expect those DNOs that have not implemented new charging methodologies to send appropriate signals to their customers about the cost of locating new demand or generation at different points on their network. Where a DNO cannot assure us that they are doing all they can to signal the costs and discourage further loading in capacity constrained areas this may have an impact upon our assessment of the proportion of this capital expenditure that is efficient and that customers should bear.

Lessons learnt from DPCR4

1.20. We are examining the success of DPCR4 in encouraging the types of behaviour that we think is in customers' interests in order to identify ways in which the settlement and incentives could be improved. We think a useful way to look holistically at how companies are performing under the control is to make an assessment of each company's return on regulatory equity over the price control period compared to the assumed return used in setting allowed revenues (7.5 per cent, post-tax, real). This approach to calculating returns entails making forecasts of costs and revenues for the final two years of the price control. It has been discussed with the companies and the detailed methodology is set out in appendix 11.

1.21. We have developed this measure to assist us in assessing overall price control performance. It will not necessarily be consistent with standard accounting return on equity metrics. We think it will help us (and consultees) understand better how companies have performed and the range of shareholder returns that have been available to companies from the settlement and the relative rewards that the 14 businesses have received so far. Our analysis is provisional, and will be updated in future price control documents, as we get new actual information (for example on capital expenditure and operating expenditure in 2008-09) and new forecast data. We may also decide to make changes to the methodology in light of responses to this consultation.

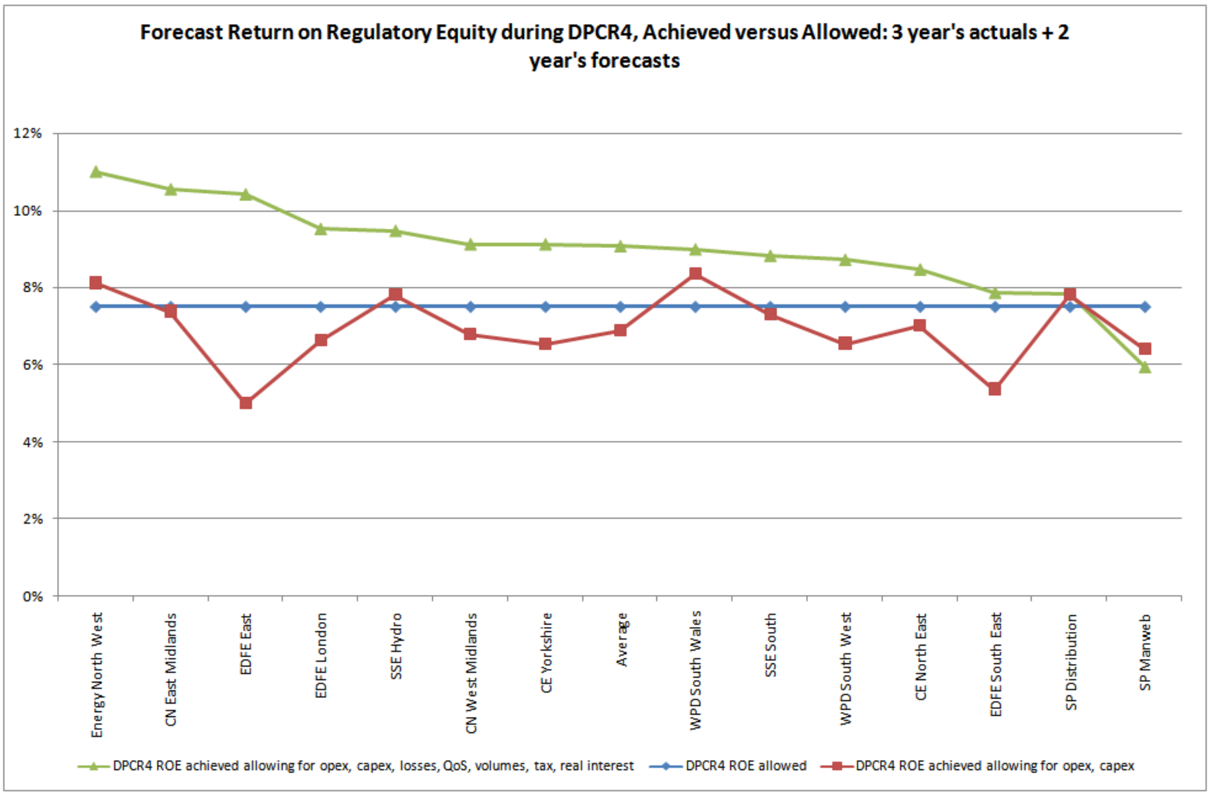
1.22. We think it is important that investors and company analysts understand the basis of our calculations but also why actual shareholder returns and company performance may differ from that presented in our analysis. Our analysis is based on a combination of actual data and forecasts. We do not, for example, take account of actual levels of company gearing and regulated companies with higher (or lower) levels of gearing may earn higher (or lower) returns than if they had geared up to our notional assumption.

1.23. Further, we have only made adjustments for what we consider to be material variances from DPCR4 allowances, and have taken account where relevant of known ex post adjustments. So we have adjusted capex variances to reflect the impact of the capex rolling incentive. We have excluded pensions, since any variance will be recovered ex post and also pass-through items. Our opex variance excludes any costs that we would not take into account when setting the price control, such as restructuring costs. We have not looked at the impact of any profits made on excluded services or de minimis activities, which are outside the price control. We have adjusted for incentive revenues on a post-tax basis only where material. There is a reopener in DPCR4 to allow DNOs to recover additional costs related to certain legislation that came into force during DPCR4. We have already adjusted the allowed revenue of four DNOs under this reopener but have not included the impact of this revenue adjustment in the analysis. This means our analysis will slightly underestimate regulatory returns, all other things being equal. By the time we publish our initial proposals we should have concluded the reopener process for all DNOs, and will include this factor in our revised calculations of forecast returns under the price control settlement.

1.24. We measure return on regulatory equity by assuming the companies are geared at our notional assumption of 57.5 per cent of RAV - not their actual level of gearing. We have reflected the difference in actual interest rates from the allowance by using a benchmark based on actual 10 year rolling average bond yields for a comfortable investment grade issuer. This allows a like for like comparison between DNOs. In practice, DNOs' actual returns will depend on their level of gearing and the extent to which their actual cost of debt has tracked market rates (this will depend on the maturity of their debt and the extent to which, for example, they have fixed or indexed linked debt). These are decisions for the companies but in looking at financial issues at initial proposals we will consider whether, in the light of actual company finance structures and market data, our assumptions about gearing when setting the cost of capital remain reasonable.

1.25. The calculations are on a five year basis, since the price control settlement is for a five year period. We have used forecasts for the final two years. We use the metric to help us see whether the companies making the highest returns from the settlement are also those companies that, based on a broad assessment, are delivering the best overall service to their customers. Our findings are set out in the figure below.

Figure 1.2 – Forecast return on regulatory equity for each DNO in DPCR4



1.26. In practice, companies' shareholder returns have ranged from around 11 per cent to around 6 per cent - a variation of +3.5 per cent to -1.5 per cent around our assumed norm. Only one of the fourteen DNOs is forecast to earn below our assumed equity return over the five year control. The most important drivers of this relative out (or under) performance are variances from allowed opex, the losses incentive scheme and outperforming our assumed cost of debt. In appendix 11 we provide details of our methodology and a detailed breakdown of the impact of all of the different incentive schemes on companies' forecast return on equity over the five year control period.

Assessment of DPCR4 return on regulatory equity (RORE)

1.27. Historically, the debate around our price control reviews has focussed heavily on the level of the allowed return, even within a relatively narrow range. It is understandable that this area attracts interest, particularly from analysts, as it constitutes a significant element of the total allowed revenue; it is a single figure rather than a complex incentive mechanism; and because the company's ability to match or outperform the regulator's assumption is easier to demonstrate than its ability to outperform other elements of the price control. However, an excessive focus on the allowed return means that the impact on returns of performance against other elements of the price control may be overlooked even though these may be of a greater magnitude than the range of allowed returns under consideration. The RORE analysis shows that this has indeed been the case in DPCR4, and we think it is a useful way of looking at the overall price control package and DNOs' performance against it in a more holistic way.

1.28. There is a wide range of returns across the DNOs, with the differences from our assumed cost of equity being driven by factors both inside and outside the DNOs' control. We think there is much more we can do to make sure that the ranking of DNOs' regulatory earnings is more closely aligned with their actual performance in terms of service and efficiency. There is scope also to consider the 'base' level of performance that is likely to secure a DNO's earnings around our assumed rate of return and how easy it is for them to start to earn in excess of this amount.

1.29. Our observations are in part due to the fact that performance under the losses incentive is a key driver of returns, with an average of 107 basis points riding on this mechanism alone. We are aware that there is volatility in settlement data, and that this volatility can have an impact on a DNO's performance under this incentive which are unrelated to the activities DNOs take to reduce losses. This indicates that when setting incentive schemes for DPCR5 and future reviews, we need to be mindful of the range of outcomes that are possible with new incentive schemes, and may wish to consider capping and collaring overall levels of return from such schemes especially where they are new and/or there is uncertainty over the scope for out/underperformance.

1.30. The other factor underlying our observations about the DPCR4 settlement relates to the lack of clear output measures which is a theme of this document and the DPCR5 review. With only limited outputs it is difficult to be sure that any capex underspend is due to genuine efficiencies, which should be rewarded. Alternatively, DNO underspend could be due to the company deferring investment required to keep the network at an acceptable level of health and then seeking extra funding at a subsequent price control to restore the network to an appropriate state of health. Or it could be that companies simply inflated their capex forecasts during the price control process. With a robust set of output measures to back up their capex forecasts, we will be able to monitor whether DNOs are maintaining the state of their network at the level they committed to at the price control review. If they are (and assuming we incentivise DNOs to submit accurate cost forecasts) then any investment deferral can be seen to be efficient because it is not increasing network risk and it should be appropriately rewarded.

1.31. We also note that there are a number of factors which could impact on a company's performance within the settlement such as differences between the forecast and outturn income received directly from customers when they receive a new connection to the network. It appears that greater than expected customer contributions may be a factor in some companies' performance so far in DPCR4 and this is why we are asking the companies for more information and looking into it further.

Implications for DPCR5

1.32. As we make progress in defining the DPCR5 settlement we will review whether the range of returns on equity that could plausibly be made by DNOs looks to be appropriate and reasonable. One relevant factor in this assessment will be the level of risk that DNOs face. As DNOs are monopoly businesses we would only expect the very highest performing companies to be earning equity returns in excess of those generally available to shareholders in non-regulated businesses.

1.33. We are also considering whether it is appropriate to place caps and collars on the revenues (and effective return on regulated equity) a company can make under individual incentive regimes (as we do with the interruption incentive scheme at the moment) - especially where factors unrelated to a company's actions may have a material effect on their performance.

1.34. As we discuss in more detail in chapter 4, we will require each DNO to commit to delivering specific outputs in return for the allowances in the settlement. This should ensure that we have a much better understanding of what lies behind any underspend in the next control period. What this means for the nature of the settlement is discussed further below. Finally, this review of the current control has underlined the importance of steps we take to incentivise DNOs to provide us with accurate forecast expenditure data which has been subjected to internal scrutiny. This has led us to take a closer look at the current information quality incentive (IQI) to see if there are ways we can improve it.

1.35. We seek views on whether the range of returns that companies have earned so far under DPCR4 is appropriate. We are also keen to understand whether others agree with our assessment of the current settlement and at a high level the key steps we are taking to address concerns.

Overview of policy proposals in this document

Nature of the settlement

1.36. In DPCR4 and in other reviews we have made it clear that we do not provide regulatory allowances for delivering a particular portfolio of projects, but rather seek to give an efficient company a settlement that will enable them to finance their business and meet their licence and other obligations.

1.37. While there is common understanding on this point, there has been a tendency for the companies to treat the settlement as a budget with the key objective being to stay within the capital expenditure forecasts used in setting the control. Ultimately we are concerned that with this approach, DNOs may not make investments needed to maintain the condition of the network and meet other customer interests. While we tried to address this to some extent by the rolling capex incentive, which means that companies only bear a proportion of any capex overspend, it is clear that companies are reluctant to overspend against their forecasts. Similarly, there is no strong mechanism to counter the incentive on DNOs to contain capital expenditure.

1.38. As noted above, we have limited output measures and this means that it may be difficult to detect when lower spending is leading to deterioration of the network and where DNOs are not meeting statutory or licence requirements. This asymmetry of information makes it difficult for us to distinguish between efficient and inefficient deferral/underspend and to take appropriate action where companies are making returns at the expense of customers' long-term needs. This may also limit DNOs' real exposure to asset and equipment price risk as they may be able to offset the impact of higher input prices by deferring the volume of work and asking for further funding at subsequent price controls.

1.39. We intend to address these concerns in the DPCR5 settlement. We propose that in return for the revenues they collect, we will require each DNO to deliver a predefined set of outputs in a sustainable manner. If any DNO considers that the price control package will not deliver them sufficient revenues to meet those outputs and to comply with their licence and other obligations, they can reject our proposals and we may recommend that the Authority refer the proposed settlement to the Competition Commission. Where a company is unable to define a suitable range of measurable outputs we may have to consider a more intrusive regulatory approach to ensure that the settlement does not create opportunities for it to earn returns that are not justified by the service it delivers to customers.

1.40. We provide an overview of the kind of outputs we have in mind in the subsection below. We are interested in reactions to our proposed approach to the regulatory settlement in DPCR5.

Dealing with uncertainty

1.41. In setting DPCR5 revenues, we face a number of significant uncertainties. Firstly, there is the uncertainty regarding the role of networks in a future energy industry that may be shaped in quite fundamental ways by the climate change agenda. Ofgem recently published our final Long-term Energy Network Scenarios (LENS) report[4] that sets out a range of plausible electricity network scenarios for Great Britain for 2050, around which industry participants, Government, Ofgem and other stakeholders can consider longer term network issues and try to ensure that the regulatory framework will allow companies to make investments with a view to meeting future challenges. Although these scenarios are over the period to 2050, and thus do not focus on the period of DPCR5, some of the developments suggested

[4] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=67&refer=Networks/Trans/ElecTransPolicy/lens

therein may begin to be seen before 2015. At one extreme, the future industry may be comprised of a series of small local networks that are mainly self-contained and make little use of the regional distribution networks we have today. However, other scenarios could involve a similar (or greater) requirement for distribution network capacity but where much greater active network management is required to address the needs of much greater distributed generation and the active participation of customers through demand side management and microgeneration.

1.42. Secondly, there is the potential scale of outturn variations in costs from the assumptions used in setting allowances. These have always existed, but have been brought into sharp focus by recent changes in key input costs, such as the volatility in copper prices and the sharp increases in the cost of raising finance in the wake of the credit crunch. There have been other significant outturn variations affecting DNOs' net costs, such as the increase in customer contributions for connections activity. The economic downturn will have an impact on a number of key assumptions that will be built into the price control settlement, including load growth and connections demand, wage rates, materials costs, interest costs and inflation. Although inflation rates are, on the face of it, excluded from consideration because we set allowances on a fixed price base and then allow DNOs to recover out-turn inflation, it may be a factor in the assessment of real cost levels.

1.43. At any price control review, forecasting is fraught with uncertainty. But the volatility in many market indices, whilst not unprecedented, is markedly higher than when the last price control was set. If this situation persists through 2009, we will consider ways of structuring the price control to manage the risks of either a) setting a price control that is too generous to the DNOs, because we have been unduly pessimistic in our assumptions or b) setting a price control that turns out to provide them with insufficient revenue to operate the networks and finance necessary investments. The tools we have to do this are discussed below.

1.44. Across our price controls we have adopted a range of approaches to sharing the risk of cost variation and other risks between companies and customers, as set out in the table below:

Table 1.1 Regulatory tools for sharing risk

	Tool	Example (DPCR4 unless stated)
DNO risk <----------------------> customer risk	pass through	Ofgem licence fee
	sharing factor	fixed incentive for capex 29-40%
	volume driver	customer numbers
	price protection	shrinkage mechanism (GDPCR)
	automatic triggers	none in current controls
	reopeners	Traffic Management Act costs
	use it or lose it	equity raising costs (TPCR)
	fixed ex ante	controllable opex (GDPCR/TPCR)

1.45. We consider that it is important to set out some overarching criteria which can be applied consistently to each of these areas in order to decide which of the options above is appropriate for each category of cost, and in particular the areas already highlighted to us by the DNOs. These include increasing uncertainty over changes in input prices and levels of demand growth and a possible need for indexation and volume drivers to address this. There are similar issues of concern to us relating to the impact of levels of economic growth on network reinforcement and connections, the cost of debt and taxation rates.

1.46. There are a number of relevant criteria in deciding which of these approaches to take to different categories of cost:

- Whether the risk is inside or outside the companies' control,
- If the risk is outside their control, are they better placed than customers to effectively manage the risk? In the case of input costs relating to capex, this hinges on the extent to which capex is deferrable, which in turn is dependent on the extent to which we can hold companies to maintaining the standard of the network. This is discussed further in chapter 4,
- Materiality - either the degree of risk/uncertainty or the scale of cost variations,
- Practicality of measurement and unforeseen consequences,

- Desirability - does it effectively insulate the network company from the risk in question? and

- Separability - each time we identify a category of costs to receive specific treatment, then unless we can clearly define this category and differentiate it from other similar costs, we are potentially creating a boundary issue that will require careful monitoring.

1.47. The application of each of these criteria to the various cost categories within the price control is discussed further in the relevant section of this document, and our initial views of the major price control components are set out in the table below, with references to the relevant paragraphs as appropriate. It is important to note that proposals to de-risk DNOs, for example on indexation of input prices, should be considered in conjunction with the power of incentives we place on the DNOs. There may be a trade-off between stronger cost and other incentives if there is greater protection against input price rises or workload fluctuations.

Table 1.2 Initial views on risk-sharing

Component	**DPCR4 treatment**	**DPCR5 initial views**
Controllable opex	Part-capitalised - this element subject to capex incentive, rest ex ante only	Totex approach - sharing factor (paragraphs 4.60 - 4.62)
ESQCR/TMA costs	Specific re-opener	Totex approach - sharing factor (4.60-4.62)
Non-controllable opex (business rates, Ofgem licence fee)	Pass-through	Pass-through
Pension costs	ex post adjustment for efficiently incurred costs re regulated business	ex post adjustment for efficiently incurred costs re regulated business (5.39)
Network investment	Subject to capex incentive	Totex approach - sharing factor (4.60 - 4.62)
Materials costs	No index	Considering index (4.49 - 4.55)
Customer numbers	Revenue volume driver	Possible conx capex driver (new customers only)(4.44 - 4.48)
Units distributed	Revenue volume driver	Capex driver for general reinforcement -only where increased demand requires it (4.44 - 4.48)
Corporation tax costs	ex ante assessment	Possible sharing factors for legislative changes (5.23-5.24)
Financing costs	ex ante assessment	Possible triggers for cost of debt (5.9-5.13)

Incentives

1.48. Since our initial consultation document in March we have given considerable thought to the range and form of incentive mechanisms included in the next price control. At this stage we are leaning towards retaining most of the mechanisms within DPCR4 as the behaviour they are designed to encourage is still relevant to the 2010 to 2015 period. However we are looking to improve the workings of the current mechanisms (in particular the IIS - see chapter 3 - the losses incentive - see chapter 2- and the IQI - see chapter 4). We will look to link rewards more closely with performance in each of these areas and to ensure that rewards are only earned for genuine improvements in performance relating to measures that the DNOs undertake. Where necessary, we will consider the need for caps and collars on incentive mechanisms as are currently in place on the IIS and the DG incentive. This may be particularly appropriate where we are introducing new incentives and/or where the potential for gains and losses under the mechanism is uncertain. We will also be giving thought to what relative influence each incentive mechanism should have on the potential regulatory earnings of the DNOs.

1.49. We have already taken steps to improve the operation of the IQI. In November 2008 we informed the DNOs that they will only be allowed to make changes to the initial forecasts they submit in February to account for changes in circumstances and new data[5]. This is to limit the ability of companies to influence the Ofgem view with high capex forecasts in February while avoiding the cost associated with a position greatly removed from the Ofgem view through an updated forecast.

1.50. We are giving serious consideration to the incentives on DNOs to innovate. Ultimately we would like an incentive on DNOs to ensure that they do everything they can to make their investment decisions 'future proof'. This means companies keeping a close watch on developments (around smart meters, zero carbon homes etc) and adapting their business strategies quickly enough to ensure that the DNOs can facilitate the changes caused by Government policies in these areas. Current incentives such as the IFI and RPZ may encourage DNOs to trial new technologies but they may not go far enough.

1.51. Finally we have given considerable thought to the relative incentive that DNOs have to make capex over opex. We are concerned that this may distort business decisions and also may make non-network solutions (such as contracting with DG or encouraging demand side management) less attractive. Our proposals for addressing this imbalance are included in chapter 4.

[5] Update letter on the DPCR5 process (151/08)

Outputs

1.52. Given the way that we are defining the regulatory settlement, output measures and associated targets for DPCR5 will be an integral part of the price control process. It is practical in this review to define and measure these outputs on a company specific basis based on the systems and information that is available in each company, although in some areas such as customer interruptions (CI) and customers minutes lost (CML) it will continue to be appropriate to have common metrics across the industry. Examples of possible output metrics include:

- Composite risk metric for load-related expenditure capturing, customers at risk, time at risk, capacity headroom, forecast demand growth etc,
- Overall network loading,
- Health indices such as the condition of transformers, switchgear and overhead lines,
- Modelled remaining useful life etc, and
- Fault rates.

1.53. For some limited areas of expenditure input measures may be more practical such as the number of substations where flood protection has been installed.

1.54. Companies that provide insufficient output information are likely to find it more difficult to convince us of their cost forecasts. For example, where there is insufficient output information we will place more emphasis on high level benchmarking or undertake a more detailed review of forecast expenditure and/or schemes. We are also considering whether, if a company is unable to provide an adequate range of measurable outputs, we should be seeking to constrain their ability to outperform against the weighted average cost of capital (WACC) or to take other measures to reflect the greater scope that company will have to increase shareholder returns at the expense, for example of network condition.

1.55. It may be appropriate to have different types of settlement for DNOs depending on the robustness of their output information. This is illustrated in table 1.3 below.

Table 1.3 Two types of settlement

Type one - Well defined outputs	**Type two - Limited outputs**
Common base cost of capital	
Challenge to DNO forecasts Tightly defined outputs which are measurable and verifiable	Extra challenge to forecasts More limited output information Greater use of CI, CML and fault rate Use of some output measures
High powered incentive scheme Easier to reach high returns based on verifiable performance against costs and outputs	Lower powered incentive schemes More difficult to earn higher returns
Limited scrutiny of underspend as long as output measures are met	More intrusive scrutiny of any underspend against capex allowances
Common CI, CML incentive rates and common standards of performance	

1.56. We will explicitly include a wider range of output measures and associated target levels of performance as part of the licence conditions for each DNO, underpinning the DPCR5 settlement. This will include requirements for annual reporting. We would like, as a matter of principle, wherever possible to agree ex ante mechanisms to adjust allowed revenues according to performance against the outputs but where we have new output measures this may not be possible and we may have to revert to ex post reviews where outputs are not delivered.

1.57. With regards to the annual reporting of output measures, DNOs will be required to maintain strong governance procedures. We would prefer not to set up a regime that requires Ofgem to closely monitor DNOs' activities and capital expenditure. We would prefer output reporting to be subject to auditing similar to that employed for the IIS incentive scheme. But to make this effective in practice, we will take very seriously any evidence of misreporting. Where a DNO is found to have misreported its outputs we will look to apply significant financial penalties and will consider making retrospective adjustments to allowed revenues. This will provide strong incentives on DNOs to accurately report their output measures, which will be important if they increasingly drive DNOs' rewards under the price control settlement.

Obligations on DNOs

1.58. We want to introduce new licence requirements for the DNOs to improve and develop the information that is available to Ofgem and the DNOs' customers. We also propose requirements for the DNOs to report progress against any new incentives or output measures.

1.59. We want each DNO to commit to a wider range of network output measures which will allow us to better assess and quantify what DNOs will deliver for customers, in return for their use of system charges. At present, there are limited output measures in place and so it can be difficult for the DNOs to justify their expenditure. In addition, we have included specific proposals in this document for a number of areas where DNOs should improve the quality and availability of information. These include proposals for DNOs to:

- Provide better information to DG customers. This could be extended to cover those customers seeking to introduce demand side management,
- Report information regarding their business carbon footprint to allow us to compare them to one another and to track their performance over time,
- Provide information on fault histories for individual customers,
- Provide single points of contact for larger industrial and commercial customers, in the event of an interruption,
- Report on progress to improve performance for worst served customers,
- Monitor the development of competition in connections for each market segment within their licensed areas, and
- Conduct telephony surveys that take a sample based on calls handled by an agent and those dealt with by automated messaging.

Interaction with the RPI-X@20 project

1.60. The RPI-X framework has been used to regulate Britain's energy networks for nearly 20 years. In March 2008, Ofgem announced the 'RPI-X@20' review - a two year project to review the workings of the current approach to regulating GB's energy networks and develop recommendations for future policy.

The rationale underpinning RPI-X@20

1.61. While we recognise that RPI-X regulation has delivered significantly lower prices, better service quality and better network reliability since its implementation, we think that it is prudent to undertake a review now for a number of reasons. First, as a matter of good housekeeping, it is right that after 20 years we assess whether the approach remains fit for purpose. Second, the challenges faced by the energy industry have changed, with the emphasis now on facilitating efficient investment to achieve environmental targets and ensure security of supply as well as on the achievement of efficiency gains. Finally, over time RPI-X has become more complex and, if possible, it may be beneficial to simplify the framework to allow customers and companies to effectively engage in price control processes.

Guiding principles for RPI-X@20

1.62. We want to be clear from the beginning of the process that we don't intend to implement unnecessary change and amendments to the current regime will only be made where there are clear benefits for consumers. There are two further guiding principles of particular relevance to DPCR5:

- No retrospective action: We understand the importance of maintaining regulatory certainty and therefore are keen to make clear that RPI-X@20 will be focussed upon the framework for future regulation of energy networks rather than reconsideration of any decisions taken in the past.

- No stranding of efficient investment: Where efficient investment has been undertaken by network companies, suitable funding arrangements will be incorporated within any framework that may be adopted following the recommendations of the review.

1.63. In line with these guiding principles, we are keen to make clear that any decisions taken regarding investment as part of DPCR5 will be carefully considered in the context of both the requirement for that investment but also in light of any potential changes that may be recommended as part of RPI-X@20 and therefore the direction of policy. In this respect, we are keen to ensure that we do not place obligations upon DNOs, through DPCR5, to undertake investments which would incur significant implementation costs and which would no longer be relevant following the conclusions of RPI-X@20. In the event that any changes are recommended under the RPI-X@20 review which could have implications for investment incentives implemented via DPCR5, we would take steps to put in place appropriate arrangements to ensure effective transition from the existing arrangements.

Timetable for RPI-X@20

1.64. The RPI-X@20 project is set to report to the Authority in summer 2010 and therefore there are clear links between this and DPCR5 in terms of the timelines that are being faced. It will be important to recognise the overlaps between these projects and to ensure that the issues exposed as part of ongoing DPCR5 discussions are fed into considerations on RPI-X@20.

1.65. An initial consultation document regarding the RPI-X@20 review is planned for publication in the first quarter of 2009 and we will endeavour to ensure that the discussions on DPCR5, in terms of any issues identified or limitations in the process, are reflected in this document. A further consultation document on RPI-X@20 is scheduled for publication towards the end of 2009 and therefore, in drafting the final proposals for DPCR5, we will take steps to ensure that the policy synergies are taken into account.

1.66. We think it is crucial to remain appraised of developments that take place on RPI-X@20, to ensure that consistency is retained between this project and DPCR5, to identify common issues under consideration in each project and to recognise small scale changes recommended by the review that may be incorporated within DPCR5. However, we are keen to make clear to stakeholders that we do not intend to implement any of the potentially significant recommendations from RPI-X@20 within DPCR5. We would be interested to hear the views of DNOs and other interested parties regarding the overlaps between DPCR5 and RPI-X@20. In particular, we would be interested to understand whether parties may have any concerns regarding the overlaps between the projects or the best way to take account of these linkages.

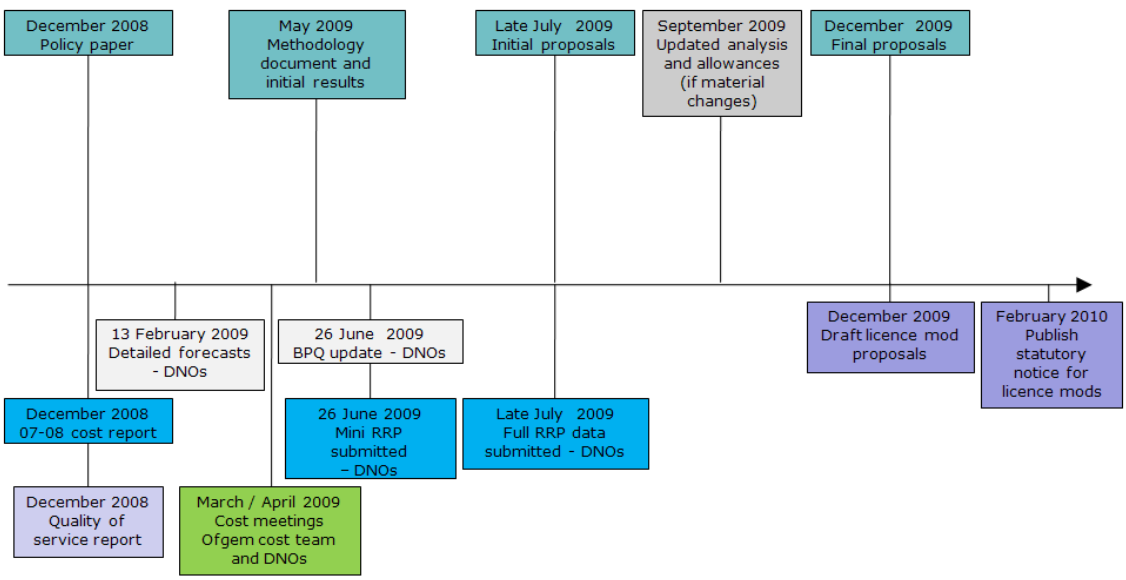
Process and timetable

1.67. We will follow an open and transparent process to arrive at our final price control proposals. We have worked to ensure that all interested parties have an opportunity to contribute fully to DPCR5. This has included meeting the consumer challenge group to discuss our proposals at an early stage and to maintain the consumer perspective. We will continue to seek to improve our consultation with interested stakeholders throughout DPCR5.

1.68. We received support to our proposed approach as explained in the initial consultation document. Chapter 6 outlines some amendments to the process, but these seek to improve both the openness of the process and allow parties the opportunity to make informed contributions throughout the review.

1.69. The full process and timetable are set out in chapter 6. Key dates are illustrated below and are as follows:

Figure 1.3 - Timeline for DPCR5



- Ofgem will hold workshops for interested stakeholders in **January 2009**
- The consultation period for this policy paper will close on **13 February 2009**
- The DNOs will also submit their detailed business plan forecasts on **13 February 2009**
- Having completed initial analysis of these plans we intend to publish a further consultation document in **May 2009**
- Having reviewed consultation responses to both the policy paper and the methodology document we will publish our initial proposals for consultation in **July 2009**
- Following feedback on our initial proposals we will publish final proposals in **December 2009**

1.70. We may publish a further consultation document in September 2009 if there are material changes to the views put forward in initial proposals due to additional information, changes in the macro-economy or if unforeseen circumstances arise.

1.71. The DNOs will have until the first week of January 2010 to decide whether to accept our final proposals.

2. Environmental issues

Chapter summary

This chapter details the main environmental policy issues that we are considering as part of DPCR5. These issues cover the role that the DNOs can play in facilitating activities that have a positive impact on the environment and tackling climate change as well as the actions DNOs can take in reducing their own carbon footprint.

Question 1: Do you agree with our view of future uncertainties and the need for DNOs to change their way of working and thinking to encompass innovation and flexibility?
Question 2: What are your views on our proposals for DNOs to provide more information to help low carbon initiatives and have we adequately identified and defined the information requirements?
Question 3: Do you agree with our proposal that all distributed generation should pay use of system charges, and if not, can you provide evidence to substantiate your specific concerns?
Question 4: Do you agree that the distributed generation (DG) incentive should be retained? Should embedded transmission be deemed relevant DG?
Question 5: What are your views on our proposals on innovation and flexibility? How would you rate their feasibility and which option is most likely to drive the more innovative and flexible behaviour that we are seeking?
Question 6: What are your views on our proposal to set an incentive on transmission grid exit charges?
Question 7: What are your views on our losses proposals, and do you have any additional comments on the option to install smart meters on low voltage substations?
Question 8: What are your views on the various aspects of the business carbon footprint proposals?
Question 9: What are your views on our proposals for refining the undergrounding scheme? In particular, should we apply caps per km of cable by voltage level or should we remove all voltage caps and just have a single overall cap?
Question 10: Do you agree with our proposed approach for the treatment of fluid filled cables?

Background

2.1. We recognise the important role DNOs can play in achieving a low carbon future - both in terms of facilitating renewable and local energy generation and energy efficiency on their networks and reducing the carbon footprint and environmental impact of their own activities (such as investing in low loss equipment and improving the energy efficiency of buildings and vehicles).

2.2. Respondents to our initial consultation noted that customers are putting increasing value on environmental issues and that customers' views in this area are likely to develop significantly during the next price control period. This message has been supported by the findings of our willingness to pay research which indicated that customers would pay a relatively high sum to see DNOs help tackle climate change. In this consultation we are seeking to test these findings and to get views on what scale of reward should be available for DNOs that perform well against the environmental incentives in the next price control.

2.3. There are some things the DNOs must do now to help tackle climate change. We are looking for ways to provide sharper incentives in these areas. But there is considerable uncertainty as to the shape of the low carbon economy, how quickly it will materialise and what this will mean for distribution networks.

2.4. In the face of this uncertainty some of the biggest challenges in this review are:

- Finding ways of incentivising the DNOs to engage in the low carbon initiatives and, as some of this uncertainty falls away, to review their business plans and practices to ensure that they do not stand in the way of progress,
- Encouraging commercial arrangements and non network solutions that will avoid or delay network investment while facilitating low carbon initiatives, and
- Deciding how much (if any) of customers' money DNOs should be planning to invest on new technology and techniques which may help to ensure that investment made now is appropriate for future needs but which, in practice, may not work as intended or may be redundant if DNOs have misjudged the future.

2.5. As part of the current price control we already have incentives in place that begin to address these issues. The DG incentive encourages the DNO to connect DG efficiently while the Registered Power Zone (RPZ) and Innovation Funding Incentive (IFI) initiatives have started to encourage the DNOs to think more innovatively through investing in research and development (R&D) and demonstrating and rolling out new technology solutions onto their network through the RPZ.

2.6. In DPCR5 we will build on the existing framework and are considering additional incentives that are strong enough to encourage the DNOs to bring forward new commercial arrangements and technologies needed to facilitate low carbon initiatives and to ensure the businesses continue to evolve given the changing environment.

2.7. DNOs' activities also have a substantial direct impact in terms of greenhouse gas (GHG) emissions, representing approximately 1.3 per cent of total GB GHG emissions. The vast majority of these emissions are caused by electricity losses (around 97 per cent of total DNO GHG emissions). We therefore need to ensure that our policies for DPCR5 encourage DNOs to reduce the carbon footprint and environmental impact of their own activities.

2.8. The policies discussed in this chapter have been informed by discussions with the DNO representatives who attended the Environment Working Group (EWG) meetings. Five meetings were held between June and October 2008 and all major policy areas were discussed. We were also informed by the responses to our consultation[6] on distributed energy as well as the responses to the DPCR5 initial consultation document.

2.9. In the following section we set out more detail on the uncertainty around the shape of the low carbon economy and how this uncertainty impacts the investment decisions the DNOs need to make for 2010 to 2015. We then set out the environmental incentives we propose to implement in the subsequent section.

DNO as low carbon facilitator

Future uncertainties

2.10. There are a large number of national environmental policies and strategies addressing the government's objective for a low carbon economy. These will have a significant impact on the investment requirements of the distribution networks and also on the role that DNOs may need to take in the future.

2.11. We are introducing incentives in DPCR5 to encourage the DNOs to be flexible and responsive. However, while there is uncertainty around the objectives and implementation details of the policies being developed there is a risk that some of the investments made in DPCR5 will not be suited to future needs.

2.12. There is some evidence that the DNOs have not been proactive in liaising with relevant bodies during the design of these policies. We are planning to organise a workshop between the Department of Energy and Climate Change (DECC), the Renewable Energy Association (REA), the DNOs and other key stakeholders in order to discuss DECC's policy developments and potential impacts on the networks.

2.13. In figure 2.1 we attempt to illustrate the potential impacts of these policies in a very high level and indicative way. They are discussed in more detail in appendix 6. We recognise that this is highly simplified and does not reflect the level, shape and location of demand and generation and how the two balance. At this point in time it is extremely difficult to anticipate the size, significance and timing of the impact of each issue, and therefore to estimate the combined impact of all the initiatives on the distribution networks.

[6] Joint Ofgem BERR consultation: 'Distributed Energy - Further Proposals for More Flexible Market and Licencing Arrangements' June 2008, (87/08).

Figure 2.1: National environmental policies and potential network impact

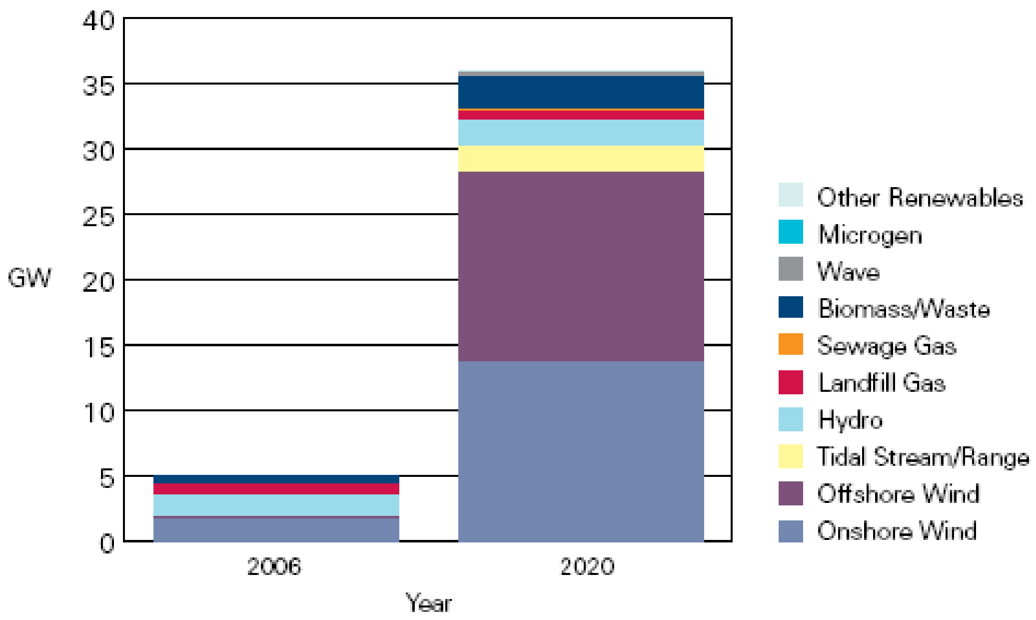
Issue	Consequence	DNO impact
UK commitment to EU 2020 renewable targets	Increased energy efficiency and DG connection	Energy efficiency and demand side management (DSM) could reduce network investment whilst increased DG could have the reverse affect and require increased investment in either passive networks or active network management
Planning targets for new developments	Partial local self sufficiency; more urban DG	All of these policies have the potential to reduce the total energy delivered by distribution networks. They could, in particular, reduce higher voltage network investment but, in contrast, there may still be a need for 'smarter' local active network management schemes
Zero carbon homes	Partial local self sufficiency; more urban DG	
Government heat strategy	More urban DG	
Micro generation feed-in tariffs	Partial local self sufficiency	
Domestic smart meters	Opportunity for DSM; better network management	Depending on the functionality of smart meters, they may be able to assist DNOs in DSM; managing the operation of their networks and reducing the need for reinforcement.
Electric cars	Electricity demand increase but storage potential	Additional network investment may be required for recharging facilities, but this may be offset by storage opportunities. Would probably require active network management
Electric storage	Enable more renewable DG connection	Storage would enable the management of fluctuations in renewable generation. Will require active network management, and potentially more network investment

2.14. For DPCR5 the DNOs are planning both significant asset replacement and also investment to reinforce their networks (as set out in chapter 4). Network assets have long operational lives and long investment lead times meaning that DNOs are planning now to install assets in two or three years time, which will be in place for at least 40 years. The level, type and location of the investment required may change depending on both the economic outlook but also the changes due to these policies and developments. It is vital that the DNOs do all they can to increase the chance that investment in the next price control period creates networks capable of accommodating the changing requirements. Without this change in mindset, there is a risk that DNOs will become barriers to the achievement of a low carbon economy.

2.15. The need for the DNOs to think strategically is reinforced by our Long-Term Electricity Network Scenarios (LENS) project which has identified five potential scenarios for 2050, four of which would require a major structural change in the electricity distribution sector. Whilst this restructuring may not occur in DPCR5, we need to ensure that DNOs are considering potential future options and making appropriate preparations now. We recognise that we have an ongoing role to play and will continue to explore the possible development of the sector and the implications for how we regulate, during the course of DPCR5 and beyond.

2.16. In order to achieve the EU 2020 renewable energy target the UK will have to significantly increase its renewable energy generation. Figure 2.2 shows a potential scenario created by the Department for Business, Enterprise & Regulatory Reform (BERR) setting out how this might be achieved. It is not known what proportion of this renewable energy would need to connect to the distribution networks.

Figure 2.2: BERR potential renewable composition to achieve 2020 targets[7]



2.17. Connecting a large volume of DG will involve a dramatic change in the way the DNOs currently operate. Historically DNOs have planned and managed their distribution networks using essentially passive[8] network designs to deliver electricity from the national high voltage transmission grid to customer premises. However these networks can prove inflexible to changing requirements (especially with

7 BERR's Consultation on the UK Renewable Energy Strategy - available at http://renewableconsultation.berr.gov.uk/consultation/consultation_summary

8 Although the initial capital expenditure requirements for passive network designs can be high, benefits can include simple control schemes and low cost operation.

variable loads and electricity flowing in both directions). Accommodating high levels of DG on passive networks would require considerable high cost reconfiguration and reinforcement. There is a corresponding impact on the transmission network, which may have implications for the role of the DNO in managing the interface with the transmission system.

2.18. DNOs will therefore need to consider more innovative approaches to manage the electricity flows on the network and increase the available capacity to facilitate increased DG connection without the need for expensive or premature asset investments.

2.19. The concept of a SmartGrid[9] has recently been developed both across Europe and America. Ofgem has played an active role in the EU's SmartGrids Technology Platform which describes a SmartGrid as an electricity network that can intelligently integrate the actions of all the users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies[10]. This would include techniques such as active network management (ANM) which uses intelligent technology and control to better use the capacity of the network and DSM which manages the level of demand and therefore electricity flows through the network. This is the type of thinking that we want to encourage in the DNOs.

2.20. Our challenge for DPRC5 is therefore to provide a framework which encourages DNOs to develop and trial new technology, to adopt new commercial arrangements (for example with DG) and to develop new ways of operating their networks that might be needed in the future. We also need sufficient flexibility in the price control settlement to allow and encourage DNOs to begin to implement these innovations as more certainty emerges.

2.21. We present our proposed framework in the remainder of this section.

Distributed generation

2.22. In DPCR4 DNOs responded to the targets set by government for the amount of energy to be supplied by renewables and combined heat and power (CHP) by 2010 by forecasting that significant volumes of DG would need to connect to the networks over the period of the price control. We responded to this by establishing the DG incentive and RPZ to incentivise the efficient and economic connection of DG to the network.

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[9] Vision presented by the Advisory Council of the Technology Platform for Europe's Electricity Networks of the Future.
[10] Definition from the Strategic Deployment Document for Europe's Electricity Networks of the Future September 2008.

2.23. The volume of DG connected to date has been far below that forecasted in DPCR4. Feedback from our initial consultation suggests that rather than being a problem with the incentives described above, the real problem has been the difficulties in getting planning permission for the development and the fact that the forecasts made for DPCR4 were overambitious.

2.24. However we recognise that there are other aspects of DNO interaction with DG, apart from connection cost, that need to be addressed to improve ease of DG access to the networks. A joint BERR Ofgem Review of Distributed Generation[11] identified a number of barriers to DG and set out four key areas for action[12]. Two of these areas; improving information, advice and guidance and making it easier to connect, are directly related to distribution.

2.25. We are therefore proposing a portfolio of measures which builds and expands on the DPCR4 measures to remove, as far as possible, network barriers to the connection of DG. These measures are summarised in figure 2.3.

[11] Published in May 2007 alongside the Energy White Paper.
[12] Four areas for action were identified by the joint BERR/Ofgem Review of Distributed Generation in May 2007: 1. more flexible market and licensing arrangements for DG; 2. more clarity on the terms offered by energy suppliers to reward microgenerators; 3. improving information, advice and guidance on options in DG; and 4. making it easier to connect to and use the distribution network. The two areas that DNOs can impact are included in figure 2.3.

Figure 2.3: Networks areas for action as identified by the Review of Distributed Generation, DPCR5 mechanisms and other initiatives to address them

Network areas for action		**DPCR5 mechanism / other initiatives**
Improving information, advice and guidance on options in DG		Mandate improved information provision by the DNOs to DG developers, in terms of both content and accessibility, including standard information on how to connect
		Industry proposal for a standard connection agreement (as a schedule to the Distribution Connection and Use of System Agreement (DCUSA))[13]
Making it easier to connect to and use the distribution network		
	Ability to connect	Initiatives to make administrative requirements for connection proportionate to generator size (G/59 and G/75)[15]
		Take account of wider DG implications in our consideration of industry code developments (such as CAP 167)[15]
	Cost of connection	DG incentive to ensure efficient cost of network reinforcement when required to connect DG
		Encourage DNOs to implement more operating expense based solutions to allow better use of network capacity and enable more DG to connect without incurring high cost network investment – by equalising the incentive to spend capital rather than operating expenses
		Encourage innovative, lower cost options for DG connection and active network management through the new innovation incentive
	Use of network	More transparent cost reflective use of system charges to ensure that DG receives benefits it provides to the system and incentivised to locate in the best locations

Information

2.26. The work conducted by Ofgem and BERR showed that an important barrier to DG connection is the lack of information, advice and guidance on connection options. Feedback from the initial consultation document was that DNOs are not doing enough in this regard and that the Long Term Development Statement (LTDS) issued by DNOs does not provide the information that generators require.

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[13] These issues are discussed further in appendix 6.

2.27. We recognise that different types of DG operator will have different information requirements. We are therefore minded to mandate a package of measures to enable all customer types to obtain easy access to information tailored to their competence level and need for technical detail. The package aims to improve information provision along three dimensions (full details of the proposals are included in appendix 6):

- Improve accessibility and greater standardisation of available information,
- Targeted guidance on the connection process and opportunities, and
- Provide indicative connection costing tools (e.g. web calculator, heat maps).

2.28. Under the proposals the LTDS would remain a technical document intended for high voltage DG. There will then be less technical information specifically tailored for those DG operators connecting at lower voltage levels that may want information about the connection process and high level indicative connection costs.

2.29. We consider that much of the information is already held by the DNOs and as a matter of good commercial practice we would expect this to be shared with customers. Hence, we expect some of the information can be made available by the beginning of DPCR5 (e.g. the updated DG Connection Guide). We acknowledge that some of the remaining documents and proposed tools will need time to develop.

2.30. We are aware that there may be information that DG developers could provide to DNOs in order to assist in facilitating the connection process. We will consider looking at the proportionality and standardisation of information DNOs require from DG developers if there is sufficient support for this proposal.

2.31. As stated before we expect DNOs to proactively consider and take actions to promote DSM. There will undoubtedly be information that DNOs could provide that would assist customers interested in engaging in DSM initiatives. Again we will consider mandating information provision, possibly in the LTDS, if it is seen to be worthwhile.

2.32. We invite views on these proposals and on whether we have adequately identified and defined the information requirements.

Use of system charges

2.33. The current charging arrangements for using the network do not adequately reward DG where it can avoid or defer the need for investment and where it brings network benefits (such as locating close to demand). We identified this as a key barrier for DG in the BERR/Ofgem study and tried earlier this year to introduce new charging methodologies by April 2010. Two DNOs (ScottishPower and Scottish and Southern Energy) rejected our proposals, meaning that they cannot be implemented as proposed. This may make it difficult to ensure we have more cost reflective DG charging in place for the start of the next price control period. We would like DNOs to continue working on revised charging arrangements but also recognise that we have to place higher emphasis on other measures that will overcome the barriers to DG.

2.34. There are other knock on effects from the delay in more cost effective charging - we will probably have to retain the separation between demand and generation revenues in DPCR5 except where DNOs can demonstrate that they have methodologies that appropriately apportion costs between demand and generation customers.

2.35. Without more cost reflective charging it is also difficult to ensure reactive power is charged according to its impact on the distribution system, in order that a strong signal is provided for efficient energy use.

2.36. The associated charging issues that impact DG are discussed in appendix 6 and will be considered as part of the charging methodology development. The specific issue of charging for generation connected before 2005 is discussed below.

Generation connected pre-2005

2.37. On 1 April 2005 we implemented a 'shallowish' connection charging policy, so that DG connecting would pay the full cost of assets installed solely for providing their connection ('sole-use') and a proportion (based on their requirements) of reinforcement costs of the shared network ('shared use'). The remaining proportion of the costs for shared use assets would then be recovered through use of system (UoS) charges, levied only on DG connected post-April 2005.

2.38. We made it clear that the exemption from these generator distribution use of system charges (GDUoS) for pre-2005 connected DG[14] would be subject to review and over the past years we have facilitated discussion on the issue. We see merits in a cost reflective charging framework with all DG exposed to cost reflective GDUoS charges irrespective of their connection date. However, we also recognise that the contractual arrangements of pre-2005 connected DG would have to be taken into account to avoid unfair regulatory treatment.

2.39. Our proposed way forward is to mandate DNOs to develop revised arrangements for charging all DG on the same basis by 2012. We have set the deadline after the start of DPCR5 in order to provide DNOs with sufficient time to

[14] 'Pre-2005 connected DG' refers to DG that connected or received a connection offer before 1 April 2005.

explore the development of such revised arrangements, which may include, inter alia, some compensation mechanisms for a subset of pre-2005 connected DG[15].

2.40. We note that some consultation respondents raised concerns over the practicality of a compensation exercise. We consider our proposals are feasible and proportionate; however we invite submissions of evidence that can substantiate specific concerns to the contrary.

2.41. We recognise the significance of this proposal and have therefore prepared an initial impact assessment, included in appendix 14.

DG incentive

2.42. The DG incentive framework was introduced in DPCR4 to encourage DNOs to undertake the investment required to connect DG in an efficient and economic manner and to generally be more proactive in responding to connection requests.

2.43. It was based on an estimated shared/reinforcement cost of £50/kW that would be incurred by the DNOs as a result of the forecast DG connections. However actual and DPCR5 forecast costs suggest a much lower figure.

2.44. We propose to retain the current DG incentive framework but amend the incentive amount to reflect DPCR5 forecast shared/reinforcement costs. Since forecasts for DPCR5 are broadly similar across all DNOs, we see no reason for any DNO to have a different DG incentive.

2.45. We recognise an issue may arise regarding embedded transmission. The government expects the development of offshore renewable generation to make a major contribution to the achievement of its emission targets. The majority of this generation will be connected to the GB electricity grid through offshore transmission cables[16].

2.46. It is anticipated that there will be situations where these offshore transmission networks connect to 132kV distribution networks onshore. This situation is termed embedded transmission. Subject to charging arrangements to be developed, we are considering treating embedded transmission as relevant DG with respect to the DG

[15] Pre-2005 DG connected under a 'deep' connection policy where the upfront connection charge included all the network costs for the lifetime of the connection (including the full cost of reinforcement and capitalised O&M). The closer the connection date is to April 2005, the more it can be considered that the 'deep' connection charge is still funding distribution assets.
[16] The term offshore transmission is currently used to describe any offshore transmission network that operates at 132kV or above.

incentive framework since it would involve network reinforcement and the incentive would promote connection efficiency.

2.47. We invite opinions on our decision to retain the DG incentive and whether embedded transmission should be deemed relevant DG.

Innovation and future networks

2.48. As stated in the Future uncertainties section, our challenge for DPRC5 is to provide a framework which encourages DNOs to make an assessment of when it is appropriate for them to adopt innovative technical and commercial solutions and encourages the development of flexible networks that can support a low carbon future. Without this framework, there is a risk that the DNOs will be late in making the necessary changes to their networks and could act as barriers to initiatives aimed at tackling climate change. There is also the risk that unnecessary investments will be made in the short term resulting in future stranded assets or that customers will have to pay for expensive 'last minute' restructuring if the networks are not fit for purpose. We do not think customers should pay for DNOs' failure to plan for the future.

2.49. Under the current regulatory framework it is arguable that there is little incentive for DNOs to move away from their current methods of planning and operating their networks. The DNOs do not face competitive pressures to gain market advantage through innovation and there may be an assumption that if they don't make changes in time the regulatory framework will allow them to recover from customers the cost of any catch up to meet changing needs. This assumption will not hold in DPCR5. In addition, innovation involves a risk of the DNOs losing money if a project fails or if additional costs are incurred in developing networks for the future that could be considered after the event to be inefficient. These risks can further disincentivise innovation in the DNOs.

2.50. We recognise that our proposals to address future uncertainty potentially overlap with Ofgem’s work on RPI-X@20. We feel that it is necessary to take steps to address uncertainty in DPCR5, in advance of the RPI-X@20 conclusion, and we welcome feedback on this.

2.51. While we introduced several measures in DPCR4 to encourage the DNOs to think beyond conventional business practice by undertaking R&D and to be more innovative in the connection of DG, we recognise that we did not fully overcome the issues described above. Therefore in DPCR5 we want to expand these measures to further encourage the DNOs to think more strategically, anticipate and influence future changes and consider how they can best prepare for the future without compromising the efficient operation of their businesses.

RPZ

2.52. The RPZ scheme was introduced in conjunction with the DG incentive in DPCR4. The objective was to encourage innovative technical solutions to connecting

DG which would offer material advantages to the DG customers compared with a conventional solution. Where an RPZ (an identifiable contiguous section of the network) is registered with Ofgem the DNO receives an amount in addition to the DG incentive for every MW of DG subsequently connected within the defined zone. Each DNO is allowed to establish two RPZs per annum.

2.53. Only four RPZs in total have been successfully registered to date by three different DNOs. Feedback from the initial consultation document suggests that the lack of RPZ implementation may be caused by the low number of DG schemes being connected (for non-network reasons), the need to partner with the DG developers and the risk that a non conventional solution may increase customer interruptions for which the DNO would get financially penalised.

2.54. We have decided to maintain the current time limits established for RPZ registration (up to March 2010) and commissioning (up to March 2012). Beyond these deadlines we expect schemes to be funded as part of the broader innovation initiatives described below.

Opex capex

2.55. Under the current regulatory framework the DNO has less financial exposure when spending is classified as capex rather than opex. This may create a potential barrier to commercial innovation (for example, contracting with DG or with customers for DSM to solve network constraints) if DNOs think the expenditure will be classified as opex. Additional spending on capex is shared between customers and shareholders while opex is borne wholly by shareholders. This means that DNOs are more likely to adopt a conventional asset based network investment solution to any network constraints rather than exploring more efficient solutions involving people or other costs classified as opex.[17] [18]

2.56. We received several responses to the initial consultation document advocating the removal of this barrier to encourage DSM and non-network solutions. This could be done either by applying a common capitalisation policy to all categories of

[17] For example ANM and DSM might involve commercial arrangements whereby the DNO makes payments to a DG operator or a customer to alter their normal pattern of generation/consumption. Under the current regulatory framework this would be classified as operating expense, with the DNO bearing the full cost. However, if it were classified as capital the DNO would only bear the capex incentive element, meaning the DNO is more likely to consider implementing the arrangements.
[18] Note that in the initial consultation document we consulted on whether we should create an incentive for DNOs free of generation and storage interests to counter the potential conflict caused by DNOs favouring affiliated DG in commercial arrangements. This was not supported by respondents, with the broad consensus that the licences prohibit discrimination, but that this could be strengthened by requiring the reporting of all payments to Ofgem.

network related costs or by allowing non-network solution costs to be added to the regulatory asset value (RAV). This matter is discussed further in chapter 4.

Innovation funding incentive (IFI)

2.57. The IFI was introduced in DPCR4 to encourage expenditure on research and development, focussed on the technical development of distribution networks to deliver value to end consumers. It has successfully encouraged the DNOs to commission a significant number of projects, some relating to the development of new ANM techniques.

2.58. In 2007 we committed to retain the IFI mechanism through DPCR5, with a flat pass through rate of 80 per cent of the project cost, and a ceiling on IFI expenditures set at 0.5 per cent of DNO revenue.

2.59. Feedback from our initial consultation document is that DNOs support the IFI but that the allocated amount is insufficient to fund the testing of high cost network equipment. However we note that only a small number of DNOs are currently spending up to the IFI limit, which challenges their view that there is insufficient funding.

2.60. We are minded to retain the IFI as a purely R&D incentive, and address innovation and flexibility using the measures described below.

Innovation and future networks

2.61. We do not think the incentives described above are sufficient to overcome the low risk, business as usual ethos of the DNOs. Therefore we are reviewing a number of options that would encourage a step change in attitudes and actions.

2.62. We want to encourage the DNOs to anticipate how future changes in energy policy will impact their networks, be engaged in the debate and influence its outcome and then be proactive in the way they continue to develop and invest in their networks. This could involve investing in a more expensive or different type of equipment that will provide more flexibility in terms of future network scenarios, trialling higher cost innovation projects which will not be guaranteed to succeed but could provide significant long term network benefits, or trialling innovative commercial arrangements.

2.63. There is a question as to whether we need to create an explicit innovation incentive in the price control when there are already significant initiatives, such as the UK Environmental Transformational Fund (ETF) which provide similar funding. If we conclude that an incentive mechanism is required, we will expect the DNOs to leverage external funds – and in any assessment of proposals we will rank projects factoring their use of third party funding.

2.64. We recognise that DNOs have different networks, pressures and constraints. DNOs will not have the same investment forecasts or opportunity to innovate. We also recognise that due to the future uncertainty we cannot, at DPCR5, define output measures or incentive amounts that will be applicable for all possible projects. Any mechanism we introduce will need to be flexible enough to cover a wide range of different projects, at different times, in different circumstances.

2.65. The options we are considering are based on three key drivers; when projects are assessed, the level and stage of project funding and whether additional rewards or penalties are applicable, depending on the outcome of the project. This is illustrated in figure 2.4:

Figure 2.4: Options and key drivers of innovation mechanism

Mechanism option	Project assessment	Project explicitly funded?	DNO reward / penalty
1. Ex-ante	Project proposals included in the FBPQ	Yes, fully	None
2. During DPCR5	Project proposals brought forward during DPCR5	Partial up front funding	Reward based on project outcome
3. Ex-post	Project outcomes by the end of DPCR5	No	Reward or penalty

2.66. These options are not exclusive. We may favour a combination, for example where we make an award based on an ex-post assessment of all the measures a DNO has taken to prepare for the future during DPCR5 along with a mechanism for up front funding of specific projects.

2.67. It should be stressed that we are not only targeting capital investment with this mechanism. We also want to see innovation in business practices, which may involve non network solutions or alternative commercial practices.

Option 1 - Ex-ante project funding

2.68. This option would involve DNOs proposing more flexible alternatives to current expenditure proposals in the discretionary expenditures table included in the August forecast business plan questionnaire (FBPQ). These proposals would be assessed and, where justified, additional expenditure allowed for the next price control period. We would provide assurances that if these assets were subsequently underutilised due to a changing environment the DNO would not be penalised or exposed to the full cost.

2.69. This option would provide guaranteed funding ex-ante, with little downside risk to the DNO. However, by itself this arrangement would provide little incentive on the DNOs to ensure that they make the best use of the allowed revenues to prepare for the future. There is also a danger that as there is more clarity around how network use is changing, the investments identified in 2009 are not the most appropriate. We consider that to be fully effective we would need to give the DNOs the flexibility to change how this part of their revenue allowance was spent during the price control period. We also think it may be necessary to combine this option with an ex-post assessment based on the outcomes of the projects each DNO implements.

Option 2 - Project by project funding during DPCR5

2.70. This option would involve DNOs submitting project proposals to Ofgem during the course of the price control period. We would determine the upfront funding requirements (dependent on factors such as planned expenditure already allowed in the settlement, amount of third party funding and a defined percentage of DNO shareholder contribution). Project approval would depend on the expected outcomes of the project – which would then be used to assess whether the implementation was successful. The reward for successful completion would be defined up front, according to the level of risk and innovation of the project and would be related to the potential value of the long term identified cost savings provided by the project.

2.71. DNO commitment for the project would be ensured through requiring a financial contribution, and successful completion of the project would be incentivised through the reward. We are considering whether to have a common fund that all DNOs could access, as opposed to individual allowances. This would allow us to leverage the available money more effectively. We are also thinking about whether Ofgem is best placed to administer such a fund.

Option 3 - Ex-post assessment of outcomes

2.72. At the end of DPCR5 we could provide a significant discretionary reward to those DNOs who have successfully improved their network flexibility or implemented innovative solutions. In addition, or alternatively, having been clear on our expectations of DNO behaviour at the start of DPCR5, we could compare DNOs' network developments at the end of the period, and penalise any DNO deemed not to have innovated or improved their network flexibility to address the changing environment.

2.73. This option would allow the DNOs to consider developing their ideas and investment plans over the forthcoming review period in reaction to changing circumstance. Funding would not be ensured up front, but a significant reward or penalty could incentivise the DNOs.

2.74. Our aim is to encourage a step change in attitudes and actions with regards to future networks and innovation whilst minimising the long term risk to consumers. We invite your views whether you agree with this aim, on the options described above and in particular which option is most likely to drive the behaviour that we are seeking.

2.75. We have prepared an initial impact assessment on our proposals which is included in appendix 15.

Treatment of transmission exit charges

2.76. DNOs pay transmission exit charges as annuitised connection charges, to recover the actual cost of the assets required to connect that DNO network to the grid, with a reasonable rate of return for the Transmission Owner (TO).

2.77. Under the current price control, transmission exit charges are treated as a cost pass-through. Hence, there is no incentive on the DNOs to influence these costs. DNOs are insulated from both the price risk (exit charges vary over time) and the volume risk (the level of exit charges increases when larger or more assets have to be installed to accommodate increased transmission exit volumes).

2.78. We acknowledge that DNOs may have a limited ability to manage the price risk, in so far as they cannot influence capital costs of assets, although it may be possible for DNOs to agree innovative deals with the transmission company for a fixed price over a period in return for defined export volume. We consider that in the medium term DNOs have influence over the grid export volumes, and can use non network solutions to limit volume increases and avoid or defer reinforcement. They can also influence the specification of assets installed. We are therefore considering setting an incentive scheme that encourages DNOs to manage and reduce transmission exit charges.

2.79. This could be achieved by setting an allowance for exit charges with the DNO retaining/bearing part of any out/under-performance. The allowance would be revised if any factors outside DNO control, such as major changes in the charging methodology, impacted the level of exit charges.

2.80. A second option would be an incentive set as a volume driver based on capacity i.e. DNOs would be rewarded for reducing the capacity requested at the transmission interface, on a £/MW basis. This mechanism would be unaffected by changes in external factors (such as transmission charging framework) but would need an additional mechanism to identify those avoided or deferred reinforcements that would qualify as a reduction in capacity requirements.

2.81. A third option would be to only allow the DNOs to pass through a percentage of the transmission exit charges, which would provide the incentive and flexibility without the need to assess avoided exit capacity. This would have to be coupled with either of the aforementioned options.

2.82. We invite views on the proposal to set an incentive on transmission exit charges.

Reducing the DNOs' environmental impact

DNOs' emissions

2.83. DNOs' activities have a substantial impact in terms of GHG emissions, with the vast majority of GHG emissions related to electricity losses (around 97 per cent of total DNO GHG emissions). Our objective in DPCR5 is to ensure that DNOs manage all of their emissions with proportionate effort and focus.

2.84. The DNO networks have additional impacts on the environment including the visual amenity of power lines and the leakage of insulating oil from fluid filled cables which are also addressed in this section.

Losses

2.85. The current losses incentive scheme applies a loss incentive to the difference between the losses in any year and the target losses (set as a fixed percentage for the five year price control period) for each DNO. The DNO retains the benefit/cost of the loss incentive in any given year for five years through the application of a rolling incentive mechanism.

2.86. Total payments to DNOs under the losses incentive scheme have averaged approximately £100m each year since the start of DPCR4. Whilst part of this arises from legacy payments under the previous DPCR3 losses incentive mechanism, DNOs have earned a total of £197m in losses incentives so far from the DPCR4 settlement. During the same period total losses on the distribution networks have increased by approximately 430GWh (or two per cent). While losses may have been higher without a losses incentive scheme, it is not clear that customers have got value for money from this incentive or that it appropriately rewards DNOs in line with their efforts and success they achieve.

2.87. Many DNOs feel that the current mechanism does not incentivise them to undertake actions to reduce technical losses (physical losses on the system) since the results of these actions are masked by the fluctuations within the settlement system. We agree that settlement volatility has made it difficult for DNOs to measure the results of loss reduction initiatives, but note that the volatility is decreasing and that the DNOs still receive the marginal benefit of any technical loss reduction despite the fluctuations.

2.88. It is difficult to measure the true volatility of the settlement system because DNOs are currently using three different losses reporting methods. We have historically allowed this on the condition that DNOs must report consistently and must inform us before any changes are made. However we now want to monitor volatility and obtain a consistent measure of losses across all DNOs. Hence we are proposing to require all DNOs to report annual losses in the same way - based on the settlement data received in that year.

2.89. There is also a view from some DNOs that the current losses incentive is flawed in that it incentivises total loss reduction and does not recognise the limited ability of DNOs to influence the level of commercial losses[19]. However the performance of EDF Energy would appear to challenge this assertion, since they have successfully focussed on reducing commercial losses and have achieved significant loss incentive benefits.

DNO proposal

2.90. DNOs have proposed and developed a hybrid approach to losses with an input system for technical losses[20] and an output system for commercial losses. The input system involves the DNO calculating the expected loss reduction per project and valuing this according to an agreed value of losses (£/MWh). The DNO would propose projects where the expected value of loss reduction exceeded the additional project cost and would receive a reward of the value of the losses avoided.

2.91. The DNOs propose to retain a lower powered variant of the current output incentive in order to reward companies that make progress in managing non technical losses. This would involve setting a target for commercial losses (the DNOs have not identified how this would be done) and determining performance against this target by measuring the losses remaining after the forecast technical losses identified in the mechanism above have been subtracted from the reported total.

2.92. This hybrid system would require industry and Ofgem agreement on the loss reductions that could be achieved by various projects (less difficult for equipment such as low loss transformers, but harder for other initiatives) and would not allow for local circumstances affecting the actual loss reduction. Ofgem would also need to satisfy itself that the proposed investment had been implemented effectively and we have concerns about the resource implications.

Ofgem proposal

2.93. We favour the current output based approach since it measures the actual losses and reductions achieved and maintains the focus on environmental benefit.

2.94. We recognise some of the benefits of the DNO proposed system and are considering allowing the DNOs to include low loss equipment expenditure in their DPCR5 capex forecasts - where the expected loss reduction justifies the additional

[19] Unaccounted for losses; theft, un-billed accounts, estimated customer accounts and inventory/estimation errors on unmetered supplies.
[20] For ease of explanation this has been described in this document as an input system for technical losses and an output system for commercial. In fact the DNO proposal allows for commercial loss reduction initiatives to be included in the input system, as long as the benefits can be quantified.

expenditure. We would retain an output incentive, but set a tougher target for each DNO that takes into account the loss reduction expected from the allowed investments. DNOs would then be rewarded or penalised by the loss incentive depending on whether they exceeded or failed to achieve these targets. This would avoid us having to audit the delivery of particular projects and would ensure that DNOs are rewarded for reducing losses.

2.95. There are some issues with target setting and incentive value in the current approach which we need to address for DPCR5.

2.96. Feedback from the initial consultation raised issues regarding target setting. Incentive payments are calculated on performance against a target rather than absolute performance. Therefore a DNO can still gain incentive benefits, even with an increase in losses, as long as it is still below the target. Whilst this is inherent in a target based mechanism we believe that the targets can be set to better reflect recent performance.

2.97. We propose that the DPCR5 losses target be set to reflect recent performance (say five years history or less[21]) but also to incorporate the agreed loss reductions generated from low loss equipment allowed in the DPCR5 capex forecasts.

2.98. The present incentive value of £48/MWh[22] was set at a value to reflect the cost of electricity and an element of the environmental costs. The initial consultation document explored the appropriateness of explicitly factoring the shadow price of carbon (SPC) (as set by the Department for Environment, Food and Rural Affairs (Defra)) into the incentive value which was well received by respondents. Using current prices, if the SPC was included the incentive value would nearly double[23]. We recognise that this value would overvalue some commercial losses. However it has been estimated that only ten per cent of losses are commercial and of this a significant proportion may be large scale theft (such as cannabis farms) which, when detected, would stop and therefore reduce electricity consumption.

2.99. We have also been exploring ways of improving the measurement of losses - as this is key to ensuring that companies get rewarded according to the impact they make on system losses rather than according to a measurement error. One DNO, Western Power Distribution (WPD), has proposed that smart meters could be installed on the low voltage side of all substations (e.g. 11kV/LV secondary transformers). Used in combination with grid supply point (GSP) metered data this

[21] Whilst we are proposing changing the loss reporting methodology, DNOs have stated that they can restate historic loss performance using the new reporting methodology which will enable us to set reflective targets.
[22] In 2004-05 prices.
[23] Calculated using the forward wholesale electricity price less the current EU Emission Trading Scheme (ETS) carbon price plus the SPC.

would allow accurate measurement of technical losses for a very significant part of a distribution network.

2.100. Whilst residential smart meters could potentially also better facilitate the measurement of technical losses it would be some years before comprehensive roll-out is achieved, we do not yet know the functionality of the proposed meters and in addition they will not measure theft where the meter is bypassed or damaged. WPD believes that these secondary transformer meters could be installed in under two years and at a reasonable cost. We requested opinions on this in our published Update Letter on the DPCR5 process (151/08) and received a mixed response from the DNOs. The majority are in favour of investigating this option further, but there are concerns regarding meter accuracy, total cost (versus benefits), the time required to roll this out and service interruptions during installation. We intend to explore this option further to test its feasibility.

2.101. We invite views on our losses proposals, including any additional comments on the option to install smart meters on low voltage substations.

Theft

2.102. Electricity theft forms part of commercial losses. It imposes significant costs on the industry and can endanger lives and property. The volume of theft is likely to have risen in recent years given the increase in electricity prices and a rise in electricity abstraction associated with cannabis farms.

2.103. There is clearly scope to augment the incentives we give DNOs to tackle non-technical losses with new arrangements on suppliers. This may mean DNOs are required to play an enhanced role - we will be considering this as part of a separate consultation process.

Sulphur hexafluoride (SF6)

2.104. SF6 is one of the most potent greenhouse gases[24]. Its usage is likely to increase in distribution networks since older switchgears are often replaced with SF6-insulated equipment and at present there is no real economic substitute.

2.105. However, analysis of DNOs' environmental reporting shows that DNOs leakage rates are on average low (around 0.6 per cent of SF6 in use in the first three years of

[24] SF6 has a global warming potential 23,900 higher than CO_2. Source: http://www.defra.gov.uk/environment/business/envrp/pdf/ghg-cf-guidelines-annexes2008.pdf

DPCR4) and in some cases nil. We understand that this is a reflection of the fact that most distribution assets that make use of SF6 are 'sealed for life' units[25].

2.106. We therefore do not propose to set an incentive scheme on SF6 emissions, since we consider it more appropriate to consider SF6 within the reporting framework for the DNO business carbon footprint, as detailed below.

DNO business carbon footprint

2.107. Most of the DNOs have in place voluntary initiatives for reporting on their emissions[26]. Some DNOs have set up a comprehensive methodology for business carbon footprint (BCF) reporting, whereas other DNOs report some elements of GHG emissions in the context of corporate social responsibility reporting (often within the wider ownership group reporting).

2.108. Several initiatives, at both international and UK level, are now established that aim to provide guidance and tools for carbon footprint reporting[27]. The majority of the DNOs that are already reporting refer to and have built on these initiatives.

2.109. Feedback from the initial consultation and subsequent discussion at the EWG revealed that there is a general consensus that, in principle, DNOs should be incentivised to consider their environmental impacts but several points of concern have been raised about the low materiality of emissions other than those associated with losses.

2.110. We are mindful that the costs of regulatory intervention shall not exceed the associated benefits but also that there is an increasing demand that the regulatory framework should put pressure, akin to consumer pressure, on DNOs to show environmental responsibility.

2.111. We therefore propose to:

- Develop a common reporting methodology for BCF, building on the GHG protocol and other existing initiatives,

[25] At transmission level, equipment using SF6 may have to be filled onsite, and in case of faults have to be fixed and refilled on-site, giving rise to higher likelihood of SF6 leakage. These technical differences are reflected in the transmission SF6 incentive, which aims to reduce leakage rates over the price control period from the current leakage level (about three per cent of SF6 in use) down to two per cent of SF6 in use. This final target is about four times higher than current average DNO performance.
[26] Losses, SF6, business travels, operational vehicles fleet, building usage, air conditioning.
[27] E.g. the GHG Protocol, Carbon Disclosure Project, Defra's conversion factors, Environment Agency's carbon calculation tools.

- Use this as a basis for a league table which reports DNOs' percentage performance in reducing their (non-losses) BCF against a baseline over time,

- Initially not attach any financial incentive to the league table, although we reserve the right to review this position after reasonable confidence in the reporting methodology has been developed.

2.112. Appendix 6 presents the details of the proposed methodology for BCF reporting. We invite views on the various aspects of the proposal and whether it is appropriate that SF6 be treated as part of the BCF as opposed to having a separate incentive.

Undergrounding in Areas of Outstanding Natural Beauty (AONB) and National Parks

2.113. At DPCR4, Ofgem introduced an allowance for network undergrounding in National Parks and AONBs. DNOs are allowed to log up actual capital expenditure on network undergrounding in these areas up to a maximum value. Entitlement to log up costs is subject to the DNO demonstrating that it has taken account of advice from local environmental groups and/or planning bodies in deciding how to best prioritise any expenditure on network undergrounding. We consider that there is a case for some continued funding of undergrounding by customers and we therefore are committed to the continuation of the DPCR4 undergrounding scheme into the next price review period. Customers valued undergrounding for visual amenity reasons highly in the willingness to pay research that we conducted earlier this year and the scheme has been positively received by stakeholders and DNOs alike.

2.114. In general, the design of the DPCR4 mechanism has worked well and there are key principles that we would like to retain such as funding being based on the removal of existing overhead lines. However, we recognise that certain features of the scheme could be improved. A more detailed discussion of suggestions and questions raised can be found in appendix 6 including:

- Extending the scheme to other protected or conservation areas,

- Avoiding new overhead lines being erected in designated areas,

- Boundary issues whereby existing lines overlap the visual boundary of designated areas,

- Interactions with DNOs' normal replacement work and the potential to combine funding from this scheme with normal replacement funding,

- Schemes that are initiated in DPCR4 and completed in DPCR5, and

- Using the allowance to fund a project officer to liaise with stakeholders.

2.115. The allowances per DNO are set out in appendix 6, along with a discussion of the per km caps. We invite views on our proposals for refining the undergrounding scheme, in particular whether we should apply caps per km of cable by voltage level or whether we should remove all voltage caps and just have a single overall cap.

Fluid filled cables

2.116. The use of insulating oil in fluid filled cables (FFCs) in distribution networks poses an environmental risk since if they leak the oil can contaminate ground water. The Environment Agency (EA) and the Energy Networks Association (ENA) have created an Operating Code, to promote best practices for FFC operational management as well as risk-based approach to strategic replacement. It also aims to benchmark current environmental performance and set improvement targets and milestones.

2.117. In feedback to the initial consultation there was some support among respondents for the risk-based approach in this Operating Code, which contrasted with a lack of any clear support for a full-scale replacement programme of FFCs.

2.118. We are minded to propose that all DNOs subscribe to the Operating Code and that they report oil leak incidents to both Ofgem and the EA in a common format on an annual basis.

2.119. We welcome DNO initiatives to develop standardised risk assessment processes and invite DNOs to undertake investments in new technologies for leak detection which are likely to result in environmental and operational benefits. DNOs have the opportunity to use IFI funding to finance such activities. We would expect examples of best practices to be adopted by other DNOs.

2.120. We invite views on our proposed approach for the treatment of fluid filled cables.

3. Customers

Chapter summary

This chapter sets out the main customer issues and areas we want DNOs to focus on during the next price control period. We propose to develop a number of new and existing mechanisms and financial incentives to facilitate and encourage DNOs to respond better to their customers' needs.

Question 1: Do you think that the range of existing and proposed arrangements will deliver the levels of service customers expect?
Question 2: What percentage of revenue/return on equity should be exposed to customer service and how should it be split between the various areas?
Question 3: Do you agree with our intention to develop a broad measure of customer satisfaction and the proposed advocacy approach?
Question 4: Do you agree with our proposed approach to connections, which of the options do you support and why?
Question 5: Do you agree with the proposed amendments to the IIS (in full) and what are your views on how incentive rates should be structured?
Question 6: Do you agree with our proposed long-term objective of DNOs being able to automatically know which of their customers are off supply and the exact times, and if so what is the appropriate timescale to achieve this?
Question 7: Do you agree with the proposed focus on worst served customers and which of the options do you prefer?
Question 8: We have raised some detailed questions throughout this chapter and the appendix. We welcome views on these issues.

Introduction

3.1. The DNOs are responsible for maintaining and developing an economic, efficient and co-ordinated distribution network. This includes responsibility for ensuring that consumers can get a reliable electricity supply, restoring power promptly in the event of an interruption to supply and connecting new customers and local generators to their network quickly and efficiently. These and other responsibilities are set out in the DNO licences, the Electricity Act 1989 and the Utilities Act 2000.

3.2. The initial consultation document set out the arrangements currently in place to incentivise DNOs to achieve reliability of supply and to address wider customer service issues including the provision of new connections. We identified a number of issues that need addressing, discussed potential areas for development including refinement of existing schemes and new measures and invited views on whether we had covered the right areas. In general the responses to the initial consultation document and our DPCR5 customer research support the broad range of measures in place and the suggested areas for further development.

3.3. This chapter sets out the results of our quantitative research and further thinking on the improvements we should make for the next price control period. These include: introducing incentives around a broader measure of customer satisfaction with their network company; improved incentives on customer interruptions; and measures to ensure better service for those seeking a new connection and worst served customers. We also put forward our proposals for the guaranteed standards, telephony and the discretionary reward scheme.

3.4. A key question across the entire price review is, what is the range of return on equity we wish to see across DNOs and how can we ensure that those DNOs that outperform our incentives and offer the best customer service are the ones that achieve the highest return on equity? The existing and proposed incentives covering customer service feed into this debate and there are questions of how much of the total return on equity should be exposed to customer service and within that how should it be apportioned between the proposed incentives.

Customers' priorities

Who are DNOs' customers?

3.5. The March consultation document identified the variety of customers that DNOs serve including domestic customers, industrial and commercial customers, generators, IDNOs and communities. We also note that suppliers have a strong interest in the service provided by DNOs[28]. The responses to the initial consultation document were broadly in agreement with this and the developments in this chapter are aimed at delivering improvements for those customers.

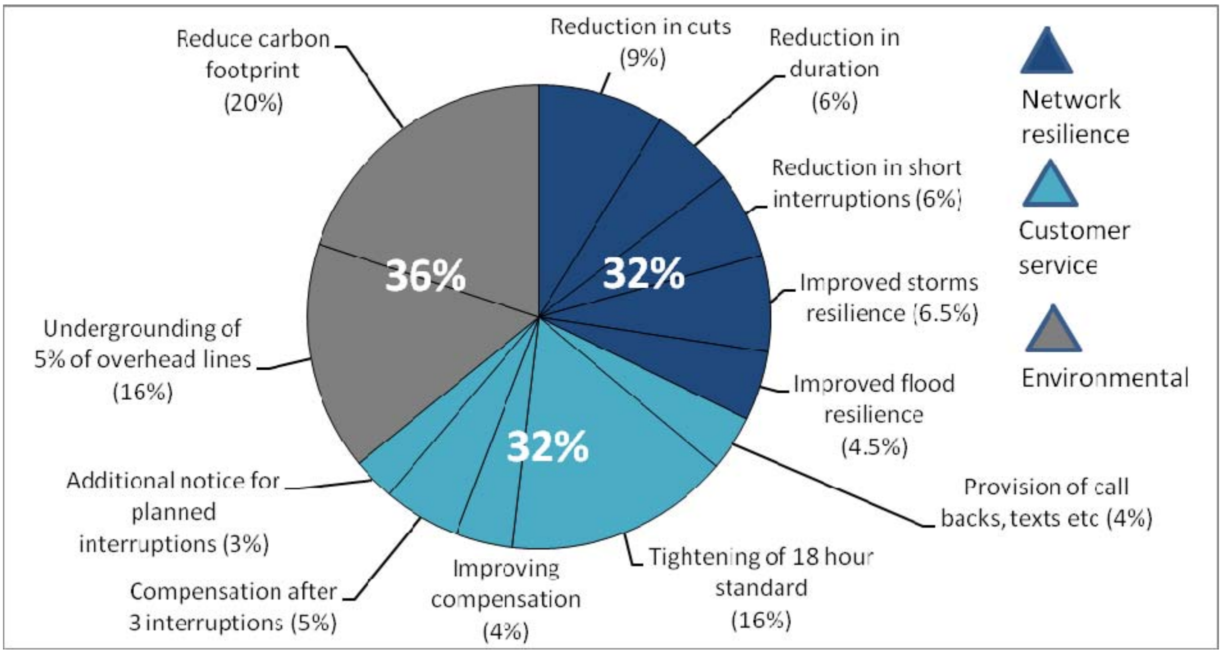
What do customers want?

3.6. As part of DPCR5 we undertook an extensive package of consumer research to get a clear understanding of what customers want from their DNOs. The research was conducted over a 12 month period and included a number of different elements[29] to cover a variety of service issues and customer groups. The questions that we asked customers concerned potential improvements that could be made to the resilience of the network, how DNOs act towards customers during an outage and the role the company plays in environmental issues. As illustrated by the pie chart in figure 3.1 customers place similar emphasis on these three areas. Other noteworthy findings were:

[28] Suppliers are often the parties that have the direct relationship with customers and therefore take on a price risk on distribution costs when they enter into fixed term contracts with domestic and non-domestic customers.
[29] 'Expectations of DNOs & Willingness to Pay for Improvements in Service, stage one: qualitative report' December 2007
http://www.ofgem.gov.uk/Networks/ElecDist/QualofServ/Documents1/1704rep03.pdf
'Expectations of DNOs & Willingness to Pay for Improvements in Service: Final Report' July 2008, (106/08)
'Worst-served Customers: Final Report' September 2008 (133/08)

- Willingness to pay for service improvements is lower than when we conducted a similar research study in 2004,
- Customers indicated low willingness to accept deterioration in service for the frequency and duration of power cuts, suggesting they are broadly satisfied with current service levels and that they would expect a significant reduction in bills for longer or more frequent power cuts,
- The priorities for improvements identified by business and domestic customers were broadly similar, and
- Worst-served customers in particular valued proactive communication during outages and in the longer term to understand the causes of repeated interruptions.

Figure 3.1 - Service improvement priorities indicated by the willingness to pay research for average domestic customers



3.7. The pie chart shows that:

- Customers value rapid restoration of supply and carbon reduction initiatives most highly, and
- Customers did not support funding improved compensation under the guaranteed standards of performance.

3.8. The consumer research has provided a very useful indication of where we should focus our attention for DPCR5 and has helped us understand more about the experience customers have when they have contact with DNOs. Nevertheless, we recognise that customers' priorities may change over time, especially in a climate of rising energy prices and a deteriorating macro-economy. It will be important to carry out further research in 2009 to help gauge any shifts in priorities and understand customers' reactions to the scale of price increases that may occur as a result of the price control settlement.

3.9. In addition to consumer research, we recognise that there are other sources of information that can provide consumer insight. For example, the Consumer Challenge Group has provided valuable feedback on customer service and connections issues and has helped us in developing our proposals for a new customer service metric. We also continue to monitor complaints to Ofgem very closely and will seek to monitor complaint handling more widely through the newly implemented complaint handling standards.

Wider communication with customers

3.10. Our consumer research suggests that customers are generally satisfied with the reliability of supply. However, both the DPCR5 research and broader evidence suggests that there are still some areas of concern. For example, the National Federation of Builders 2008 Utilities Survey[30] cites poor communication from utility providers as the main source of dissatisfaction for developers obtaining connections. Similarly, our consumer research with worst served customers highlighted the lack of information and explanation for repeated interruptions from DNOs.

3.11. Our objective is to incentivise DNOs to behave like companies facing competitive pressures that need to satisfy customers consistently in order to retain them and stay in business. We accept the views of respondents that the telephony scheme (which monitors and rewards DNOs for performance in dealing with particular enquiries over the phone) provides a narrow incentive for DNOs to improve customer service overall. DPCR5 provides a valuable opportunity for DNOs to place greater focus on customer service across a range of activities. Developing a broad measure of customer satisfaction plays an important role in achieving this.

Customer satisfaction

3.12. We have two customer satisfaction work streams: developing a broader measure of customer satisfaction to better understand the performance of the DNOs in this area and then designing a new incentive around this measure, with a reward

[30] National Federation of Builders
http://www.builders.org.uk/news.aspx

and/or penalty; and improving the existing telephony incentive scheme. We propose running the new broad customer satisfaction measure with the telephony scheme for the early part of DPCR5 with a view to replacing the telephony incentive with the broader customer satisfaction incentive mechanism as soon as is practicable within the price control period.

Broad customer satisfaction measure

3.13. The initial consultation document sought views as to how we could broaden customer satisfaction measures to better capture the full range of interactions with DNOs. We propose that the new measure should have the following features. It should:

- Capture customers' satisfaction with the overall experience of contact with the DNOs across a range of the activities and services they provide to their customers,
- Take account of the key service attributes that matter to customers,
- Enable robust and simple comparisons between DNOs,
- Provide DNOs with useful feedback on their performance against factors driving satisfaction or dissatisfaction, and
- Be cost-effective to run.

3.14. Our discussions with DNOs suggest that some form of advocacy scoring may be a useful measure of assessing customer satisfaction. Under such an approach, customer satisfaction is assessed on whether customers would recommend the company to others. Some DNOs have trialled such advocacy measures with some success. However, there is clearly a question about the principle of recommending a monopoly business such as a DNO where there is low consumer choice and involvement. We intend to take advice from market research professionals on the best way of phrasing such an overarching question for electricity distribution. We could adopt a similar approach to that taken by the Office of Rail Regulation (ORR) to measure the train operating companies' satisfaction with Network Rail's service[31]. The ORR's measure assesses satisfaction by eliciting how respondents feel about Network Rail by using a scale of customer response ranging from spontaneously critical to advocate. We favour using a mixed methodology with a number of lead-up questions to provide some context to respondents and to enable DNOs to identify the drivers of their customers' satisfaction/dissatisfaction.

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[31] Annual assessment of Network Rail 2007-08' September 2008' www.rail-reg.gov.uk/upload/pdf/378.pdf

Table 3.1 - Initial ideas for the scope of the broad customer satisfaction measure

Attributes of customer satisfaction	Customer interactions
▪ Handling of enquiries, problems and complaints ▪ Staff – helpfulness, friendliness, competence ▪ Quality and availability of information (website and by phone) ▪ Being kept informed ▪ Ease of making contact ▪ Speed of service ▪ Satisfactory completion of work	▪ Planned and unplanned power cuts ▪ New connections ▪ Service alterations ▪ Supply upgrades ▪ Plant enquiries ▪ Complaints ▪ Obtaining compensation

3.15. An important consideration is whether DNOs would be best placed to undertake the surveys themselves or whether they should appoint a market research agency to undertake the surveys independently. If DNOs conducted the surveys themselves it could provide valuable real time feedback which they could act on. However, it could be more complicated to audit and relies on DNOs being consistent in their interviewing. Using a market research agency would bring some uniformity to the surveys, which is important for comparative and public scrutiny purposes.

3.16. We are interested in views from respondents on:

- whether you agree with the overall approach proposed for measuring and incentivising customer satisfaction,
- relevant considerations in developing an advocacy metric for DNOs,
- whether the scope of the lead-up questions proposed are appropriate,
- whether the scope of the customer interactions is appropriate, and
- who should conduct the surveys.

Telephony incentive scheme

3.17. Our view is that there is a continuing role for the telephony scheme as we work towards developing and implementing the new metric during DPCR5. The proposed improvements that can be made to the scheme include:

- streamlining the existing survey questions,
- widening the scope of the survey to include calls answered by messaging,
- taking account of the proportion of unsuccessful calls in assessing incentive payments, and

- having the DNOs run a uniform assessment, approved by Ofgem, by contracting with a single provider.

3.18. Amendments to the telephony scheme are discussed in more detail in the appendix 7.

Connections

3.19. The initial consultation document identified connections as an important theme for DPCR5. It set out our concerns with the pace at which competition is developing and the inadequate service that some customers receive. Our concerns were supported by a number of consultation responses from industry stakeholders as well as by the findings of the 2007-08 connections industry review (CIR).

3.20. A recent survey by the National Federation of Builders has highlighted worsening service levels for electricity connections over the last two years, with delays and communication being particular problems[32]. Ofgem still receives many complaints about connections as demonstrated by table 3.2. We see DPCR5 as an opportunity to review the existing regulatory treatment of connections, taking into account pace of development of competition and potentially implement a fresh approach.

Table 3.2 - The volume and type of electricity distribution complaints to Ofgem (April 2006 until 30 September 2008).

Category of complaint	Authority determination	Informal advice	Referrals to energywatch
DT.1 - Quality of supply	0	1	160
DT.2 - Reliability of supply/supply distribution	0	0	106
DT.3 - Connections/alterations of supply	11	179	323
DT.4 - Difficulty or delay in obtaining a connection	0	0	233
DT.5 - Excavations/Reinstatement	0	1	36
DT.7 - Network safety	0	1	20

[32] http://www.builders.org.uk/news.aspx

Key issues with current framework

Competition in connections (CinC)

3.21. Ofgem's policy is to facilitate competition on a national basis across all voltages of connection. However, there are significant variations in the uptake of competition nationally and across different voltages. Competition has been most prevalent in the Midlands and North West where the DNO market share is as low as 16.8 per cent (CN East at HV). In other parts of the country competition is limited with some DNOs retaining market shares as high as 100 per cent (CE Electric and WPD at HV).

3.22. We have identified a number of potential barriers to competition in the electricity connections market. These have been informed by responses to the 2007-08 CIR. They include:

- There is no ability for DNOs to earn margins on competitive connections activities and this may make it difficult/impossible for competitors to compete for business,
- There are limits to the activities that are open to new entrants (i.e. for safety reasons independent connection providers (ICPs) cannot complete the final connections),
- DNOs can provide poor cooperation with new entrants (i.e. delays in providing services that are not open to competition, unclear technical specifications, roll out of LV live jointing, lack of transparency on non-contestable charges),
- Differing service levels and requirements across the country,
- Unwillingness of ICPs and DNO contractors to compete independently and risk losing lucrative DNO contracts,
- High start up and accreditation costs for ICPs,
- Lack of ICP engagement in regulatory processes,
- Complexity of electricity connections processes compared to gas makes the market less attractive to ICPs,
- Non-standard adoption agreements,
- Application of the inspection and testing regime, and
- Shortage of skilled engineers.

3.23. We are concerned that the current 'one-size-fits-all' approach to the way we regulate the connections market has not led to the establishment of effective competition that is in the best interest of customers. We are also concerned about the barriers to competition that remain. The following sections explore the options for a regional, segmented approach to regulating the connections market and the potential for strengthening incentives on DNOs to facilitate competition.

Options examined

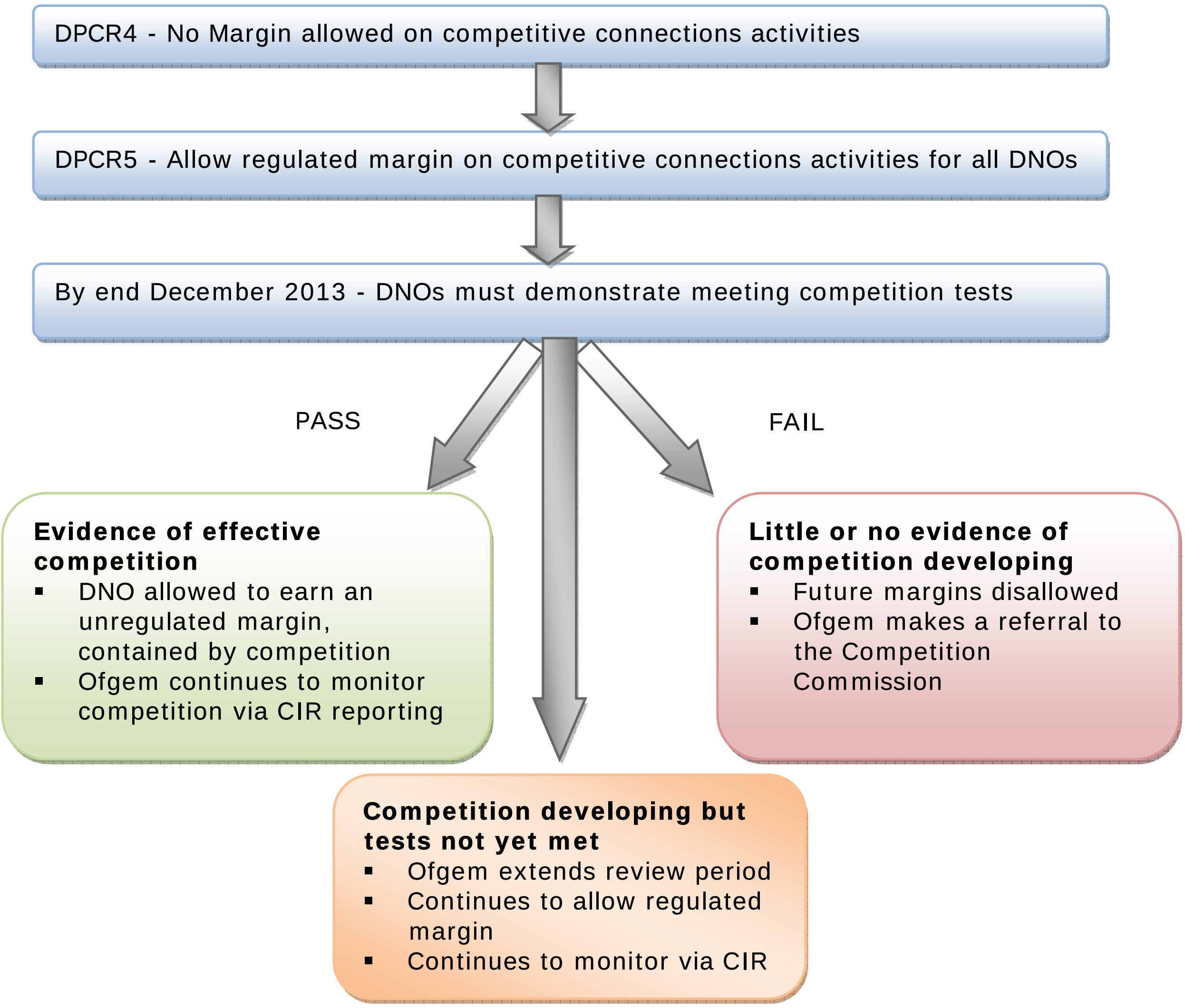
3.24. We have set out a number of options to strengthen incentives on DNOs to promote competition and improve service to customers in the transition to competition.

3.25. In other markets where we have sought to facilitate competition, for example in metering, we have allowed the incumbent to earn a regulated margin (or return) in the expectation that any headroom will help to attract new market entrants and that customers will benefit through the pressure that new market entry will bring to raise efficiency, lower prices and/or improve service. It is possible (and some DNOs say) that one reason competition is not developing is that we have not taken this approach in connections. DNO margins on contestable connections are currently removed through the way the Regulatory Asset Value (RAV) is updated for actual connections costs and income, although DNOs retain a limited benefit through the capex rolling incentive. The effect is that any margin the DNOs earn effectively reduces the RAV, discouraging DNOs from earning a margin.

3.26. Allowing DNOs to earn regulated margins may encourage price competition and attract new entrants to the market potentially resulting in better, faster services and/or lower costs for connections customers in the long term. We are keen to ensure that the regulatory arrangements are not hampering the development of competition. We invite views as to whether setting regulated margins for DPCR5 would facilitate competition and if so what would be an appropriate level to set them at given the potential for prices to increase in the short term as a result of allowing the margins. Appendix 7 explores and seeks views on the connections activities and market segments where we could allow a margin.

3.27. We would review whether competition has developed after a period of three years in the relevant market segment for the DNO in question, although DNOs who could prove that they have met the tests earlier than this would be free to submit their case at any time. This could mean that some DNOs are in a position to earn an unregulated margin from the start, or early on in DPCR5. We would assess this through a number of competition tests which provide a broad view of the effectiveness of competition regionally and in particular market segments. Further details of potential competition tests are set out in appendix 7. If a DNO meets the competition tests by the given deadline, the DNO would be able to earn an unregulated margin. If a DNO fails the tests, depending on the extent of failure, Ofgem could disallow future margins or consider a market investigation referral to the Competition Commission. Our options and timescales are set out in figure 3.2.

Figure 3.2 - Proposed treatment of competitive connections for DPCR5



Connections provided by the DNO on a non-competitive basis

3.28. DNOs are the providers of last resort for connections. Currently, there is some regulation to protect customers that opt for the DNO to provide the entire connection but this is mainly concentrated in the market segments where it was considered that competition would be unlikely to develop (i.e. small scale LV connections). In the gas connections market regulation is much tighter and large amounts of compensation, in the region of £350,000 during 2007-08, are being paid out to the benefit of customers where the GDNs fail to provide an appropriate level of service. The existing protection for electricity customers taking the non-competitive route is summarised in table 7 in appendix 7. We consider that there is a strong case for rolling out and strengthening regulation for customers that choose the non-competitive connections route and for segments of the connections market where competition has not developed or is unlikely to develop. This includes the provision of broader standards on accuracy of quotations and completion of connections work.

Options examined

3.29. Although some protection for customers choosing non-competitive connections already exists, we consider that the lack of uptake of CinC points to the need for greater protection in segments where competition has not developed and for customers choosing the non-competitive route. Responses to the initial consultation document were generally supportive of further regulation for connections provided by the DNO on a non-competitive basis. The options we are considering involve further service and price protection including:

- guaranteed standards of performance and a licence condition to improve the accuracy of connections quotations and the time taken to deliver them for all connections customers,
- price regulation in market segments where competition is not feasible to ensure consistent treatment of customers and minimise the potential for charging disputes,
- a price accuracy scheme for all connections quotations to enable customers to challenge the DNO over the price they are quoted, and
- a cost efficiency incentive for market segments where competition is not feasible which could result in cost savings for customers.

3.30. We invite views as to:

- the merits of the options set out in appendix 7,
- the combination of options that would deliver improvements for connections customers, and
- the connections market segments that would benefit from further price and service protection.

Guaranteed standards of performance

3.31. The guaranteed standards set out service levels that should be met by each DNO. These standards have been set to guarantee a level of service that is reasonable to expect companies to deliver in all cases. If the distribution company fails to meet the level of service required, it must make a payment to the customer subject to certain exemptions. The current guaranteed standards cover a range of activities including supply restoration, connections and voltage quality. The initial consultation document sought views on whether the existing standards still cover the right areas and offer adequate levels of protection for customers. With the exception of connections discussed above, we are satisfied that the strength and scope of the current standards is adequate and we do not propose making amendments for this purpose. However, we consider that a number of refinements should be made such as updating compensation payments for inflation. This is discussed in detail in appendix 7.

Customer service reward scheme

3.32. This initiative was introduced at DPCR4 to reward DNOs that demonstrate best practice for consumers in areas that cannot be easily measured or incentivised through more mechanistic regimes. Each year, a total reward of £1 million is available across the chosen categories. In the initial consultation document we committed to reviewing the current scope and value of the scheme including whether it should incorporate DNO performance in tackling climate change. We have decided that the customer service reward scheme is not the appropriate vehicle for incentivising DNOs to reduce their carbon footprint given that reporting arrangements are being developed as part of DPCR5 (see chapter 2). We consider it is appropriate to retain the current three categories[33] but refocus these on the following areas:

- Communication with worst-served customers,
- Approach to ongoing stakeholder consultation, and
- Assistance for other categories of customers such as vulnerable customers who only have electricity.

3.33. We understand that the recognition DNOs can secure from winning a reward under the scheme may be more important than the level of the monetary reward. We therefore propose to maintain the value of the scheme at £1 million per year.

3.34. Embedding best practice identified during DPCR4 is an important objective for the scheme as we move towards DPCR5. We are keen to ensure that customers nationwide benefit from the service improvements that the scheme has given rise to. We would value views on the options for ensuring that DNOs adopt best practice. Best practice could be enshrined in the licence or become part of the minimum requirements for the DPCR5 discretionary reward scheme. These options are set out in more detail in appendix 7.

[33] Priority customer care, wider communication and corporate social responsibility

Quality of service interruptions incentive scheme (IIS)

Overview

3.35. As discussed in chapters 1 and 4 we are looking to place greater emphasis on outputs as part of this review. The current IIS places symmetric penalties and rewards on customer interruptions and customer minutes lost, with each DNO having individual annual targets for both measures. While the interruptions information and incentives are well developed we consider that there are a number of key areas for further thought and development:

- How much of the total return on equity exposed to incentives should be allocated to interruptions,
- The long-term path for improvement in interruptions information,
- Whether we should be signalling/committing to long-term incentives for interruptions where the targets will either stay the same or tighten over time,
- Incentive rates, and
- General refinements to the IIS.

Return on equity exposed to the IIS

3.36. Currently three per cent of base revenue is exposed to the IIS, which on average implies a +/- 1.6[34] per cent upside (or downside) on the allowed return on equity. In the wider context of the price review, given the overall spread of return on equity of 4 per cent up to 11 per cent, we are interested to know whether respondents think that this level of risk/reward associated with the IIS is appropriate or whether it should be increased or reduced.

Long term objective

3.37. While the quality of interruptions information has improved very significantly over the past seven years due to major efforts throughout the industry, the current incentive framework still relies on some estimation and information provided by customers to their DNOs. We would like to signal a long term objective, to be in place for the DPCR6 period if not before, of DNOs being able to automatically know which of their customers are off supply and the exact times. This information should be available in real time on DNO websites and customers should also be able to access their interruption history via their DNO's website. Business representatives on

[34] Minimum ROE 1.47 per cent, maximum ROE 1.71 per cent.

Ofgem's Consumer Challenge Group have expressed a strong desire to have more real time information and we believe that this would also be of benefit to other customer groups as well, such as vulnerable customers. We anticipate that as smart meters become more commonplace this information should be more readily available.

3.38. We invite views on this long term objective and also the possible ways, such as through a licence condition, of achieving it by the beginning of DPCR6 at the latest.

Duration of the scheme

3.39. As part of DPCR5 we are looking to place greater emphasis on output measures. This includes broadening the scope of output measures to include condition indices and the risks of certain parts of the network not being able to meet demand.

3.40. However, it is also important to consider whether we should be signalling longer-term targets and incentives in this area. Interruptions are typically a lagging indicator of performance and the impact of investments now may not be visible for a number of years. A five year price control period may result in potential quality of service investments yielding no return whereas the benefits if measured over a longer timeframe may in reality make such projects economic. We consider that there would be benefits in signalling enduring, long-term incentives on interruptions. As part of this there may be merit in extending the period for which the targets and incentive rates apply. In proposing to use a broadly similar methodology for target setting for DPCR5 as was used for DPCR4, we think it is a good time to explore the merits of committing to the IIS for more than just the next period. We invite views on whether the IIS should be set beyond DPCR5.

3.41. An additional element to the setting of longer-term targets would be that future targets would only ever be at the existing levels or tighter, except under exceptional circumstances. As such, where a DNO chooses to defer capex investment in one price control period it would still be required to deliver the expected performance levels in the future and if not it would be penalised under the IIS. We have reflected this in our draft unplanned targets by setting the starting point as the lower of either current three year average performance or the unplanned 2009-10 target. We have then set the 2014-15 target as the lower of either the 2014-15 benchmark or the starting point for DPCR5. Tying this approach to the broader capex programme for DPCR5 it may then be appropriate to tighten targets for DNOs even where the benchmarking indicates otherwise. We invite views on how past and future capex and targets should be incorporated into setting targets for DPCR5 and beyond.

Incentive rates

3.42. The DPCR4 approach to setting incentive rates, using a uniform percentage of revenue exposure and equal percentage performance bands around the targets, resulted in varying incentive rates for interruptions and minutes lost across individual DNOs. Under this approach the same project designed to deliver the same benefit to customers may currently yield a positive return for one DNO but not for another DNO due to these differences in incentive rates. Customer research for DPCR5 points to greater uniformity in incentive rates across the country, with the possible exception of London, where there was significantly higher willingness to pay[35]. An additional consideration we will need to take account of when setting the IIS incentive rates is the interaction with the capex rolling incentive. The following example illustrates these issues and we invite views on how these should be addressed.

Table 3.3 - Example of impact on NPV of differential IIS and rolling capex incentive rates

	DNO A	DNO B
Cost of scheme	-£100,000	-£100,000
Reduction in interruptions	2,000	2,000
Number of connected customers	2,000,000	2,000,000
Reduction in customer interruptions	0.1	0.1
Customer interruptions incentive rate £ million	£317,000	£75,000
Capex roller	29%	40%
Pre-tax WACC	6.9%	6.9%
Present value of costs	-£27,128	-£37,418
Present value of benefits (5yr)	£130,325	£30,834
Net present value	£103,197	-£6,584

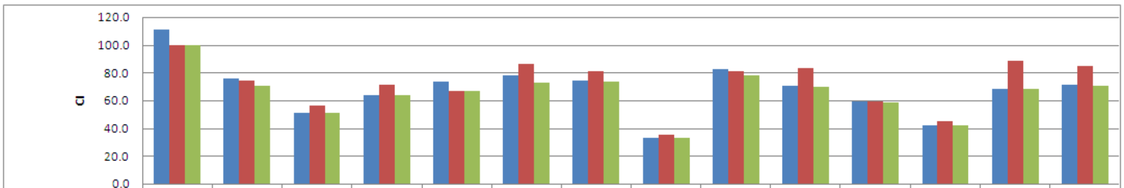
3.43. The two DNOs have different customer interruptions (CI) incentive rates, due to their differing CI targets and base revenues. As the DPCR4 methodology took an equal percentage of base revenue, which varies by DNO, the actual amount of money exposed to IIS is different across DNOs. DNOs also have individual CI and customer minutes lost (CML) targets. For CIs a bandwidth of 25 per cent around the target was used to determine the maximum and minimum bounds of the incentive. Applying a fixed 25 per cent to a differing CI target and then dividing this number into a different sum of money results in varied incentive rates as shown. In the example the different incentive rates mean that the same reduction of 0.1 CI in both DNOs gets rewarded more highly in DNO A than in DNO B. Over the course of a five year review period this results in a difference of almost £100,000 in terms of reward between DNO A and DNO B. The varying capex rolling incentive rates also mean that the cost of the scheme borne by the DNO varies, in this case by just over £10,000. Taken together these differences result in the net present values presented in table 3.3.

[35] The weighted average willingness to pay for a reduction in the frequency of power cuts per year was around £4 per customer for all DNO areas bar London, where the figure was in excess of £13 per customer.

Refinements to the IIS

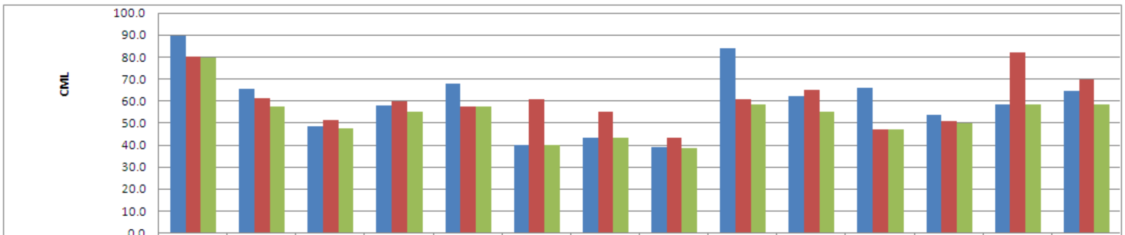
3.44. Most responses to the initial consultation document supported maintaining the IIS in generally the same format as DPCR4. They supported some modifications to some of the benchmarking and target setting methodologies, the exceptional events mechanism and the interruptions and minutes lost incentive rates, which are discussed in appendix 7. Figures 3.3 and 3.4 below show the updated draft unplanned interruptions and minutes lost targets for 2015 based on the proposed benchmarking and target setting methodologies as set out in appendix 7. The principal differences with the initial consultation document figures are the setting of targets at current average performance rather than benchmark for a number of the DNOs and a greater weight being given to DNOs' own fault rate, particularly for underground circuits where improvements in fault rates are likely to be extremely costly. The final targets will need to reflect any further methodological changes and the costs associated with any required performance improvements. As discussed in appendix 7 we have also taken into account the DPCR4 2009-10 targets. It may be necessary to relax targets where the costs of improvement beyond the existing 2009-10 targets are deemed to be uneconomic.

Figure 3.3 - Draft unplanned 2015 CI targets vs. 2010 unplanned targets



	CN West	CN East	ENW	CE NEDL	CE YEDL	WPD S Wales	WPD S West	EDFE LPN	EDFE SPN	EDFE EPN	SP Distribution	SP Manweb	SSE Hydro	SSE Southern
Current 3yr average	111.2	75.6	50.8	64.0	73.5	77.8	73.9	33.0	82.9	70.8	59.3	42.3	68.3	71.1
2010 CI target	100.1	74.0	56.4	71.0	66.6	85.9	80.6	35.4	81.3	83.2	59.5	45.2	88.7	84.7
Draft 2015 CI target	100.1	70.6	50.8	63.6	66.6	73.0	73.7	33.0	77.6	70.1	58.7	42.3	68.3	70.5

Figure 3.4 - Draft unplanned 2015 CML targets vs. 2010 unplanned targets



	CN West	CN East	ENW	CE NEDL	CE YEDL	WPD S Wales	WPD S West	EDFE LPN	EDFE SPN	EDFE EPN	SP Distribution	SP Manweb	SSE Hydro	SSE Southern
Current 3yr average	89.7	65.5	48.7	58.2	68.0	39.9	43.2	39.1	83.8	62.4	66.1	53.9	58.6	64.8
2010 CML target	80.4	61.4	51.2	59.8	57.6	61.0	55.4	43.4	60.9	65.3	47.1	51.1	82.1	69.6
Draft 2015 CML target	79.7	57.3	47.7	55.4	57.6	39.9	43.2	38.5	58.3	55.0	47.1	49.8	58.6	58.4

3.45. In light of the responses to our initial consultation document, the results of the customer research and ongoing work we invite views on the following:

- The proposed changes to the benchmarking and target setting methodologies set out in appendix 7,
- The preferred approach to incentive rates taking account of the analysis set out in appendix 7, and
- Other possible refinements discussed in appendix 7.

Worst served customers

3.46. The IIS scheme has been successful at improving average reliability across all customers but does not appear to be improving performance for those customers experiencing on average more than five high voltage interruptions per annum, over 300,000 customers nationally. The existing IIS tends to encourage investment in areas that will provide the greatest overall benefit for a majority of customers. Worst served customers typically represent a small proportion of the total customer base and are often located in low density and/or rural areas. For these reasons, expenditure on these customers is often difficult to justify.

3.47. As the majority of worst served customers are situated in rural /or low density areas, Ofgem also has a statutory obligation in regard to customers in rural areas under section 3A-(3)(d) of the Electricity Act 1989.

3.48. In our initial consultation document we set out three mechanisms to encourage service improvements for worst served customers. The overall response from DNOs was positive with most supporting targeting worst served customers via a set allowance or an incentive, which are discussed further below. The allowance is expanded upon further in appendix 7. Our consumer research indicated that guaranteed standards would not be the most appropriate tool for tackling worst served customers. DNOs supported this view given the large sums of money that would be circulated amongst customers without driving any substantive change in performance. They also raised concerns with the potential introduction of perverse incentives which could act to the detriment of customers. Our work to date has been aided by the DNOs and input from the Consumer Challenge Group and we invite all stakeholders to contribute their ideas to the development of this policy.

3.49. The options we have looked at in this section are aimed at delivering improvements in network performance through investment in the network. Findings from our research with worst served customers showed that in many instances contact with DNOs was poor. There were calls for more accurate information and proactive communication, particularly of the outage causes. These results mean that it is essential that DNOs improve communication with worst served customers along with any improvements in network performance. We propose to include communication with worst served customers in the customer service reward scheme and would expect to see greater DNO engagement with such customers.

Defining the worst served customer

3.50. The two most appropriate ways for defining worst served customers are in terms of the number of customer interruptions and/or the aggregated duration of interruptions. An increase in interruptions experienced by a customer is due to network issues, which could be mitigated with appropriate expenditure on the network. On the other hand, restoration time can be affected by both network issues and external factors. The distance between the local depot and the fault, field resource limitations, spares issues and noise restrictions can all cause an increase in restoration time and these cannot always be mitigated through capital expenditure on the network. Although the field resources and spares could be overcome with operational expenditure, it may not be cost effective to have significant stocks of spares and additional staff solely for dealing with the worst served. We consider that defining worst served customers in terms of customer interruptions is more appropriate than aggregated customer duration. We invite views on how we propose defining worst served customers.

Incentive

3.51. An incentive mechanism would require defined outputs over a particular period, which may prove difficult to set for just one price control period and as such we believe it is not the right time to introduce an incentive. With no historical information on individual worst served customers, Ofgem would have to rely on DNOs to put forward the potential improvements from expenditure on worst served customers and this may result in inappropriate target levels. Measuring changes to performance for worst served customers would be difficult without better and longer ranging historical information to help counteract annual fluctuations/variability. This adds to the complexity of setting a scheme solely for DPCR5. A high level incentive could be placed on the rolling average performance of all customers experiencing more than a defined number of interruptions, although individual schemes may then get masked by ongoing volatility.

Defined allowance for worst served customers

3.52. A defined allowance could be made available in DPCR5 on a 'use it or lose it' basis. DNOs would be required to provide annual scheme plans on a rolling basis, with these plans specifying amongst other things, the expected improvements in performance, which would then be reported on over the course of DPCR5.

3.53. Given current information, we propose that a specified allowance is adopted for worst served customers in DPCR5. We would also pursue improved reporting for all worst served customers and particularly those targeted by DPCR5 expenditure. As our understanding of performance for worst served customers increases over time, we may be able to incorporate or move toward an incentive based approach.

3.54. The key issues with this approach are determining an appropriate amount for the allowance and deciding on how the allowance should be distributed. The total amount for DPCR5 could be based on:

- An amount similar to that provided for undergrounding in National Parks and Areas of Outstanding Natural Beauty in DPCR4 - £64 million,
- Projected costs for worst served customers schemes indicated in the August FBPQs - £69 million, or
- Worst served customers' contribution to the cost of existing quality of service initiatives (the rationale being that worst served customers pay for, but do not generally receive the benefit of current quality of service initiatives and the worst served customer fund would allow DNOs to reinvest these costs to the benefit of the worst served) - £42 million.

3.55. The total allowance could be allocated amongst DNOs either equally or according to the proportion of total worst served customers in each DNO area.

3.56. These options are detailed further in appendix 7 as well as the possibilities for non-network solutions. Ofgem proposes that any amount relating to worst served customers in DPCR5 be split evenly amongst the thirteen DNOs having customers defined as worst served customers, as this would reduce the impact on customers in those DNOs with relatively high proportions of worst served customers and low overall customer numbers. Additionally, the ability of DNOs to carry out the work needs to be taken into consideration and our preference is to provide allowances which are used.

4. Networks

Chapter summary

In this chapter we set out further details on our approach to setting the price control for DPCR5 including the nature of settlement and the associated behaviours we are seeking to encourage. We discuss DNOs' performance during the DPCR4 period and their costs forecasts for DPCR5 and the issues arising from this. We outline potential changes with regards to the cost incentives and to place greater weight on network output measures. We also discuss our latest thinking on the methodology for cost assessment.

Question 1: Have we identified the right behaviours for DNOs? Are there others which should be included?
Question 2: What action should we take where a DNO has deferred investment and created a backlog in DPCR4?
Question 3: What approach should we manage to deal with volume uncertainty?
Question 4: What approach should we take to price uncertainty?
Question 5: Should we be looking to equalise incentives for opex and capex? If so, what approach should we adopt?
Question 6: Do you consider that we should make refinements to the IQI? If so, what changes should we make?
Question 7: What action should we take where DNOs provide insufficient output information as part of their February FBPQ?
Question 8: Do you agree with our proposed approach to assessing network operating costs and indirect costs?
Question 9: Do you agree with our proposed approach for assessing network investment?

Introduction

4.1. We raise a number of key issues in this chapter associated with the management of electricity distributions networks. We are concerned with the extent to which DNOs are underspending their capex allowances in the price control period to-date and the impact that this may be having on levels of network risk. To the extent that this is creating a backlog for DPCR5, we consider that the recovery of the backlog should be funded by shareholders and not customers unless DNOs can identify clear efficiency benefits that benefit customers. For example, if they can show that asset replacement costs are falling and the delay has lowered the total cost to customers and that customers have not faced significantly greater network risk because of the deferral.

4.2. The initial DPCR5 forecasts submitted by the DNOs in August showed very significant rises in both capex and opex. Clearly, these forecasts need to be considered in the context of significant uncertainties in the current macro-economic environment which impact on both cost pressures and growth in network demand and we expect these factors will lead to significant reductions in the main forecasts for the price control that the DNOs will provide in February. However, the scale of the costs means that we will be strongly challenging the DNOs underlying assumptions and it will be critical for the DNOs to demonstrate that they are taking all possible steps to consider options for contracting with DG and using demand side management to manage possible capacity constraints. This will be even more important if more cost reflective charges are not in place. The DNOs will need to explain not only that they are forecasting appropriate volumes of new assets and replacement, but also that these are being replaced by the right assets. Like-for-like solutions may not always be appropriate given potential changes to the operation of the network in the future with more DG or changes in the pattern of demand. It will be important to avoid excessive risks of stranding.

4.3. We will be looking to ensure that DNOs have taken all appropriate steps to develop their condition based information and approaches to managing risk as well as investing in new or replacement assets.

4.4. In the context of significantly rising network investment , it will be essential for the DNOs to explain to us the outputs that their plans will be delivering. Outputs will form a key part of both the assessment of the DNOs' costs and will be an integral part of the final settlement to ensure that DNOs deliver on their promises and provide value for money. We are considering varying the final settlements for DNOs depending on the robustness of the ouput information. Where DNOs provide more robust information, we will look to set more highly powered incentives and apply less scrutiny to outturn costs provided the DNOs meet their outputs.

4.5. We consider that there are a number of ways we could develop the current incentive framework on the DNOs and we also need to introduce revised mechanisms to deal with uncertainty. We discuss options for introducing additional investment drivers or triggers and introducing input price indexation for changes above a certain materiality. We are placing restrictions on DNOs revising their forecasts at DPCR5 and discuss a number of other options for improving the IQI.

4.6. We outline a range of improvements to our cost assessment methodology including focusing on more robust cost drivers for different areas of costs, appropriate cost groupings and refinements to both the load related and asset replacement modelling.

Nature of the price control settlement and behaviours

4.7. There are a range of behaviours we are seeking to encourage from DNOs with regards to how they invest in and manage their network assets which underpins this form of settlement and the associated incentives. Each DNO should:

- Meet all licence and statutory requirements including developing an economic and efficient network and delivering pre-defined output measures:
    - the level of expenditure should take account of the long-term requirements of customers,

  - o the network should be managed at an efficient cost for an appropriate level of risk and other outputs,
  - o investment should be at a sustainable level, and
  - o decisions should be made on the basis of whole-life costs including the impact on the environment,

- Ensure the safety of employees and the public
- Reassess the cost base regularly to improve efficiency,
- Support innovation and development,
- Invest in a sustainable workforce,
- Facilitate the development of competition in supply and generation and development of DG,
- Maintain adequate records to meet regulatory reporting requirements, and
- Provide forecasts of an efficient level of costs to manage their networks on the same basis that the plan and manage their business internally.

Performance against the DPCR4 settlement

DPCR4 actual capex performance

4.8. Table 4.1 shows the performance of individual DNOs and the industry against the DPCR4 capex allowances.

Table 4.1 Individual DNO capex performance against DPCR4 allowances[36]

£m 2007/08 Prices	05/06 - 07/08				DPCR4 (05/06 - 09/10)			
	Actuals	Allowance	Over/under spend	%	Actuals/ Forecast	Allowance	Over/under spend	%
CN West	392	392	0	0%	623	650	-27	-4%
CN East	359	387	-29	-7%	627	643	-17	-3%
ENW	295	363	-68	-19%	545	603	-57	-10%
CE NEDL	214	219	-5	-2%	377	365	12	3%
CE YEDL	272	292	-20	-7%	489	486	4	1%
WPD S Wales	153	155	-2	-1%	256	257	-1	-1%
WPD S West	225	224	1	0%	372	373	-1	0%
EDFE LPN	302	349	-47	-13%	534	581	-46	-8%
EDFE SPN	277	374	-96	-26%	571	620	-49	-8%
EDFE EPN	437	542	-105	-19%	868	902	-33	-4%
SP Dist	269	292	-24	-8%	470	486	-16	-3%
SP Manweb	297	314	-17	-6%	514	523	-9	-2%
SSE Hydro	134	167	-33	-20%	266	277	-11	-4%
SSE Southern	318	439	-122	-28%	664	731	-67	-9%
Total	**3944**	**4510**	**-566**	**-13%**	**7177**	**7497**	**-321**	**-4%**

4.9. Overall capex for 2005-06 to 2007-08 is 13 per cent below the DPCR4 allowance. On average this adds 1.1 per cent to the return on equity with the smallest impact across the DNOs being 0.7 per cent and the largest 1.5 per cent. EDFE LPN, EDFE EPN, EDFE SPN, ENW, SSE Southern and SSE Hydro have all spent significantly less than their allowance. DNOs have highlighted a range of factors affecting their ability to deliver the increased capital investment plans during the early years of the period including delays in mobilising their contractors, shortages of skilled labour and management decisions to reduce volumes of work to meet costs.

4.10. They have also highlighted a number of other reasons for lower expenditure relative to their allowances such as reduced asset replacement due to improved asset management, the exclusion of related party margins and connections margins from affiliates, increases in connections income and load increases not materialising.

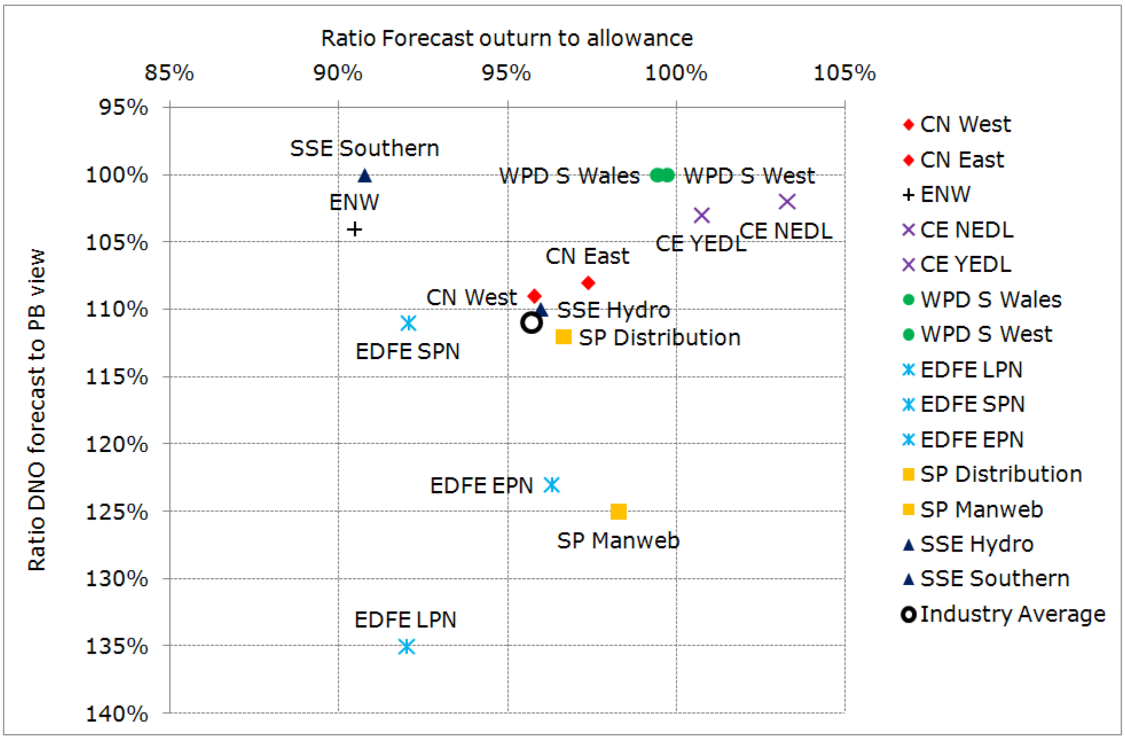
4.11. Given that we set unprofiled capex allowances at DPCR4, it is not surprising that there would be some underspend in the early part of the period followed by higher expenditure in the latter years. In total DNOs are forecasting to outturn 4 per cent below the DPCR allowance with individual DNO ranging from an 10 per cent below to 3 per cent above. These forecasts depend on DNOs achieving their own forecasts for the remaining two years of DPCR4.

[36] There are currently a number of areas of costs associated with changes to the Electricity, Safety, Quality and Continuity Regulations (ESQCR) 2002 where reopener provisions were include in DPCR4 to manage uncertainty in costs. Taking this into account, the degree of underspend is higher than we have noted.

Key issues regarding actual DPCR4 capex performance compared to DNO forecasts

4.12. Figure 4.1 shows the ratio of the DNOs' final capex forecast at DPCR4 to the view of our capex consultants (PB Power) on the vertical axis. It shows the ratio of DNOs current forecast outturn to the allowance on the horizontal axis.

Figure 4.1 Ratio of DNO forecast to PB view and DPCR4 and forecast out-turn expenditure against their allowance



4.13. DNOs whose forecasts were relatively high compared to PB Power's view and are now forecasting to underspend the allowance are shown to the lower left of the plot. Those DNOs whose forecast were broadly in line with PB Power's view and are now forecasting to spend in line with the allowance are shown to the upper right of the plot. On average DNOs' forecasts at DPCR4 were 11 per cent higher than PB Power's view while their current forecasts for out-turn expenditure are 4 per cent lower than the allowances. This highlights two key issues with performance in DPCR4.

Reduced investment expenditure despite real increases in input prices

4.14. DNOs have indicated that real increases in input prices have increased capex by up to 20 per cent in the DPCR4 period to date. Despite this, they are forecasting that their capex will out-turn significantly below their own DPCR4 forecasts. This may indicate that DNOs have managed price risk in DPCR4 by reducing volumes of investment. This is a result of a range of factors including investment:

- being deferred to offset higher input prices due to self-imposed financial constraints,
- being deferred due to delivery constraints,
- not being required due to poor/over forecasting,
- not being required/being deferred due to changes in user behaviour, and
- being deferred due to improved asset management.

4.15. Where network investment has been deferred due to a self-imposed financial constraint (for example, where a DNO has chosen not to overspend its allowance) or deferred work due to delivery constraint, there will be an impact on the future level of network investment. The deferred investment creates a backlog that will need to be caught up in future. It is also likely to adversely impact network performance such as fault rates or network loading or at the very least there will be an increased risk of poor performance until the backlog can be recovered.

4.16. In the final proposals for DPCR4 it was made clear that customers should not be expected to fund a back log or catch up programme. Ofgem's current thinking is that any backlog created as a result of the DNOs constraining the level of investment in DPCR4 should be recovered at a cost to shareholders not customers unless DNOs can clearly identify efficiency benefits that benefit customers.

4.17. DNOs have also presented examples where investment has been deferred due to better asset management. This is where better information or policies have allowed the performance and/or risk to be managed at the same level with a lower level of investment. We consider that where this is supported with appropriate output information this is an efficiency improvement and no further action should be taken.

Increased customer contributions

4.18. Actual and forecast connections income for DPCR4 is 41 per cent higher than the assumption underpinning the DPCR4 net capex allowance. Higher contributions reduce the level of net capex compared to the allowance and may result in DNOs underspending. There are a number of potential reasons for actual contributions being higher than forecast including the nature of the forecasts themselves, changes in the volume and mix of connection work, changes in the connection charging methodologies and the removal of tariff support.

4.19. We are looking into this issue further and gathering additional information from the DNOs. As part of the work in taking forward cost incentives we will look to ensure that changes between forecast and actual contributions do not have a significant impact on the cost incentives. One way of doing this may be to do a true-up for actual connections contributions.

DPCR4 opex performance

4.20. Table 4.2 below shows the performance of individual DNOs and industry against the DPCR4 opex allowances.

Table 4.2 Individual DNO performance against DPCR4 opex allowances (£m 2007-08 prices)

£m 2007/08 Prices	05/06 - 07/08			
	Actuals	Allowance	Over/under spend	%
CN West	188	169	19	11%
CN East	189	180	9	5%
ENW	145	163	-18	-11%
CE NEDL	122	117	5	4%
CE YEDL	161	141	20	14%
WPD S Wales	99	110	-11	-10%
WPD S West	148	133	16	12%
EDFE LPN	160	142	18	12%
EDFE SPN	172	144	28	20%
EDFE EPN	278	223	55	25%
SP Dist	151	152	-1	0%
SP Manweb	154	126	28	22%
SSE Hydro	95	104	-9	-9%
SSE Southern	199	189	10	5%
Total	**2261**	**2092**	**169**	**8%**

4.21. DNO expenditure for the DPCR4 period to date is £169m (8 per cent) above the allowances (2007-08 prices). While the allowances were set to decrease by 1.5 per cent per annum actual costs have increased year-on-year. On average this reduces the DNOs' return on equity by 0.3 per cent. The range is from -1.2 per cent to +1.9 per cent.

4.22. The key areas of increased opex over the past three years relate to tree cutting for continuity of supply and network resilience, in response to changes in the Electricity, Safety, Quality and Continuity Regulations (ESQCR) 2002, non-operational capex and engineering management and clerical support.

4.23. The extent of opex overspends is a key area of concern for the DNOs and they argue that, in setting opex allowances at DPCR4, we did not take adequate account of the impact of forecast increases in capex on their indirect costs. We will consider this in the round with capex where DNOs have significantly underspent the allowances.

Further efficiencies

4.24. Some DNOs have suggested that they are already operating efficiently while others have been very open in explaining that they have further efficiencies to achieve and in some cases set out plans for attaining these. This highlights that further efficiency can be realised through comparative analysis and this will continue to play a key role at this review.

4.25. Most DNOs, even those suggesting they have further efficiencies to make in their own business, have suggested that the scope for further improvement for the industry as a whole (or frontier shift) has now been exhausted as they have been working under an RPI-X regime for nearly 20 years. Those DNOs have suggested alternative approaches to setting allowances at, or around, the current level of costs.

4.26. In competitive markets companies continually strive to make improvements in efficiency to maintain or increase profitability. We think it is important to mimic this incentive for DNOs and consider that there are potentially further efficiencies to be realised by all DNOs and will be carrying out analysis in this area. We will be looking at trends in total factor productivity and operating costs for comparator industries and looking at the most relevant components of the retail price index.

DPCR5 forecasts

4.27. We gathered initial forecast information for DPCR5 from all of the DNOs in early August. These initial Forecast Business Plan Questionnaire (FBPQ) responses were based on analysis the DNOs undertook earlier in the year and therefore do not reflect the latest economic conditions. In the majority of cases the forecasts were based on assumptions that economic growth would continue at historical trend rates. In practice economic conditions in recent months have seen us move to a position of decline in economic activity in the last quarter and there have been significant reductions in many of the relevant commodity prices. We would therefore expect the revised forecasts in the February FBPQs to show significant reductions in expenditure.

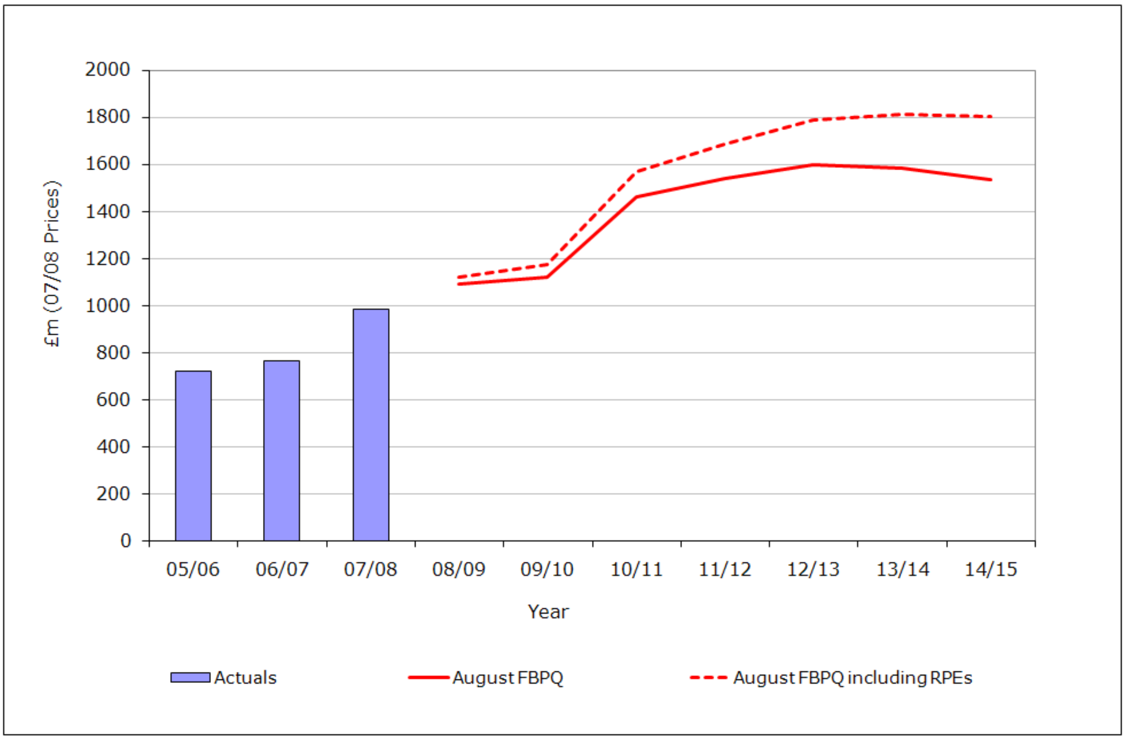
4.28. The following section contains a high level summary of the initial FBPQs. More detail is provided in appendix 17 which also includes a DNO commentary on their forecasts.

Network investment forecasts

Overview of forecasts

4.29. Figure 4.2 shows the network investment[37] forecast (excluding distributed generation) for all DNOs for the remainder of DPCR4 and DPCR5. It also shows actual spend to date. DNOs are forecasting that network investment will increase by 65 per cent from DPCR4 to DPCR5 excluding real price effects and by 82 per cent including real price effects. The forecasts for individual DNOs are highlighted in table 4.3 below. Given the scale of the increase in network investment we are reviewing and challenging the DNOs forecasting assumptions in detail.

Figure 4.2 Actual and forecast network investment for DPCR4 and DPCR5



[37] Network investment is the total expenditure on network assets excluding overheads, less all income received from customers for new connections and reinforcement as determined under the charging arrangements. It only includes direct costs or prime expenditure as defined by the current RRP rules. Network investment shown in figure 4.2 is therefore on a different basis to capex shown in table 4.1. Capex shown in table 4.1 includes a proportion of network operating costs and indirect costs in accordance with the DPCR4 rules.

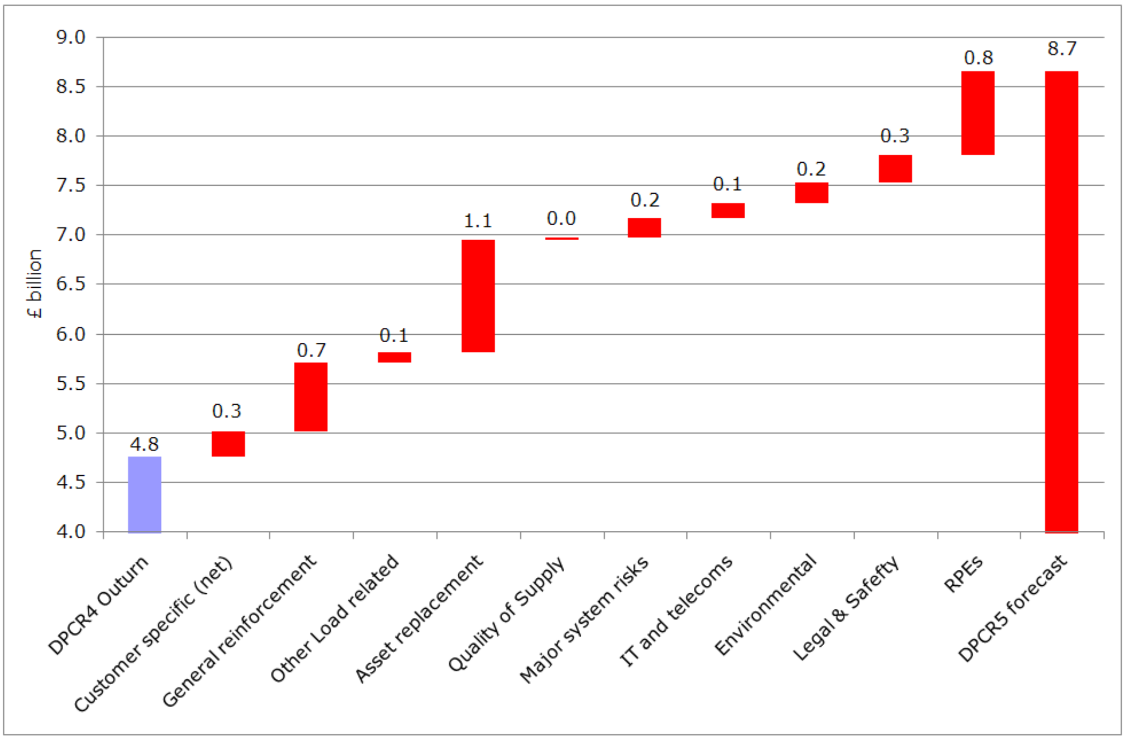
Table 4.3 Actual and forecast network investment by DNO for DPCR4 and DPCR5

£m (07/08 Prices)	DPCR4				DPCR5			Change DPCR4 to DPCR5
DNO	Actuals	Forecast	RPEs	Total	Forecast	RPEs	Total	%
CN West	243	143	6	392	602	83	685	75%
CN East	213	179	7	399	682	95	777	95%
ENW	189	176	5	370	622	59	681	84%
CE NEDL	138	105	2	246	368	18	386	57%
CE YEDL	177	145	3	325	501	24	525	61%
WPD S Wales	87	59	1	147	269	21	290	97%
WPD S West	138	101	2	242	374	30	404	67%
EDFE LPN	203	152	4	359	753	57	810	126%
EDFE SPN	179	201	5	384	628	50	678	77%
EDFE EPN	275	283	7	565	924	72	995	76%
SP Distribution	169	151	13	333	506	148	653	96%
SP Manweb	202	185	16	402	681	196	877	118%
SSE Hydro	60	84	3	147	216	22	238	62%
SSE Southern	198	245	8	452	602	57	659	46%
Total	**2470**	**2211**	**82**	**4763**	**7727**	**931**	**8658**	**82%**

Key factors contributing to the rise in network investment

4.30. The main factors explaining the forecast increases in network investment are shown below.

Figure 4.3 Key elements of the increase in network investment



Load related expenditure

4.31. The DNOs are forecasting that gross load related expenditure will increase by 26 per cent in DPCR5 and net load related expenditure[38] by 96 per cent excluding real increases in input prices and distributed generation. The largest contributory factor to this is a £690 million (59 per cent) increase in general reinforcement[39]. The DNOs are also forecasting a £260 million (10 per cent) increase in gross customer specific demand investment with no corresponding increase in customer contributions. We have concerns with this given the large increase in customer contributions seen in the DPCR4 period.

[38] Gross load related expenditure is the total cost associated with new system assets connected by the DNO to the network because of a new connection, system reinforcement associated with a new connection and general reinforcement of the network due to an increase in demand, Net load related expenditure is the gross spend minus costs that are paid up front by the customers that are connecting as a connection charge (customer contributions).
[39] General reinforcement costs are the costs associated with new or upgraded system associated due to an increase in demand.

Condition based asset replacement

4.32. At DPCR4 network investment allowances were set that included an allowance for increased expenditure on asset replacement compared with DPCR3. This was mainly due to the need to replace poor condition assets, many of which were installed in the 1950s and 1960s. In their August FBPQ submissions the DNOs are forecasting a further increase in condition based asset replacement of 39 per cent (excluding RPEs).

Other areas of non load related investment

4.33. The DNOs have forecast £854 million for other areas of investment in DPCR5 including improvements in quality of supply, work to mitigate the risk of prolonged widespread power outages to central business districts (CBDs) and to mitigate the risk of prolonged widespread power outages due to flooding, work on operational IT and Telecoms, legal and safety requirements and environmental schemes. Real input prices

4.34. Increase in real input prices account for approximately 24 per cent of the total increase in network investment.

Issues identified during the cost visits

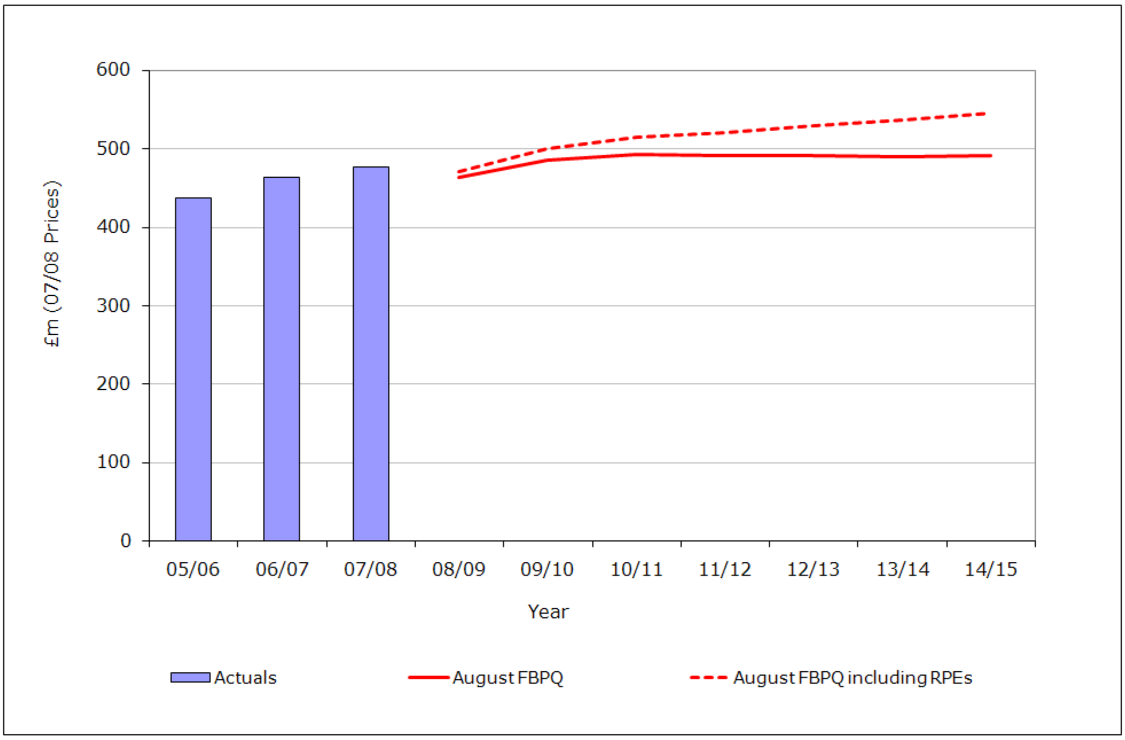
4.35. During September and October 2008 we conducted a series of DNO visits to discuss capex performance for DPCR4 and their August FBPQ forecasts for the remainder of DPCR4 and DPCR5. Forecasts for expenditure on the primary network were generally built up from individual identifiable schemes where possible (bottom up), with top-down modelling used to forecast expenditure requirements further out (towards the end of DPCR5). Expenditure on the secondary network was built up from top down modelling or on the perceived need to maintain or reduce equipment fault rates. In some cases bottom up forecasting appeared to be unconstrained by any top down view or any consideration of overall system risk. In particular we would look for DNOs to quantify the effect that their plans have on system risk and to justify any changes.

Network operating cost forecasts

Overview of forecasts

4.36. Figure 4.4 shows the DNOs' actual network operating costs to date and the forecasts for the remainder of DPCR4 and DPCR5. The costs include faults, inspections and maintenance and tree cutting work excluding atypical items as defined in the Regulatory Reporting Pack (RRP) Rules. These are the forecast costs as reported by the DNOs and have not been adjusted for DPCR4 capitalisation rules.

Figure 4.4: Actual and forecast network operating costs for DPCR4 and DPCR5



4.37. In total DNOs forecast that network operating costs will increase by 5 per cent between DPCR4 and DPCR5 excluding real increases in input prices and 13 per cent including such increases. The figures for each DNO are set out in table 4.4.

Table 4.4: Actual and forecast network operating cost by DNO for DPCR4 and DPCR5 period

£m (07/08 Prices)	DPCR4				DPCR5			Change DPCR4 to DPCR5
DNO	**Actuals**	**Forecast**	**RPEs**	**Total**	**Forecast**	**RPEs**	**Total**	**%**
CN West	126	78	0	204	192	0	192	-6%
CN East	143	85	0	228	214	0	214	-6%
ENW	81	64	2	147	162	15	177	21%
CE NEDL	76	43	1	120	104	5	109	-9%
CE YEDL	109	71	2	181	170	8	178	-2%
WPD S Wales	55	38	0	94	102	4	106	13%
WPD S West	81	57	1	138	151	5	157	14%
EDFE LPN	100	69	2	171	175	17	192	12%
EDFE SPN	114	77	2	192	197	15	212	10%
EDFE EPN	173	124	2	299	327	23	349	17%
SP Distribution	76	53	3	132	141	25	166	25%
SP Manweb	85	54	4	143	163	32	195	36%
SSE Hydro	43	37	3	83	100	15	114	37%
SSE Southern	118	97	3	218	252	31	284	30%
Total	**1378**	**947**	**24**	**2349**	**2451**	**194**	**2645**	**13%**

4.38. CN and CE are forecasting lower expenditure in the DPCR5 period and relatively small increases in input costs. WPD and EDFE are forecasting modest increases in costs overall although for EDFE a larger proportion of the increase is due to increase in input costs. ENW, SP and SSE are forecasting higher increases in costs including large increases in input costs.

Indirect costs and non operational capex forecasts

Overview of forecasts

4.39. Figure 4.5 shows the DNOs' actual indirect costs and non-operational capex to date and the forecasts for the remainder of DPCR4 and DPCR5. The costs are as defined in the Regulatory Reporting Pack (RRP) Rules and exclude atypical items. These are the forecast costs as reported by the DNOs and have not been adjusted for DPCR4 capitalisation rules.

4.40. In total DNOs forecast that indirect costs and non-operational capex will increase by 9 per cent between DPCR4 and DPCR5 excluding real increases in input prices and 15 per cent including such increases. The figures for each DNO are shown in table 4.5.

Figure 4.5: Actual and forecast indirect costs and non-operational capex for DPCR4 and DPCR5

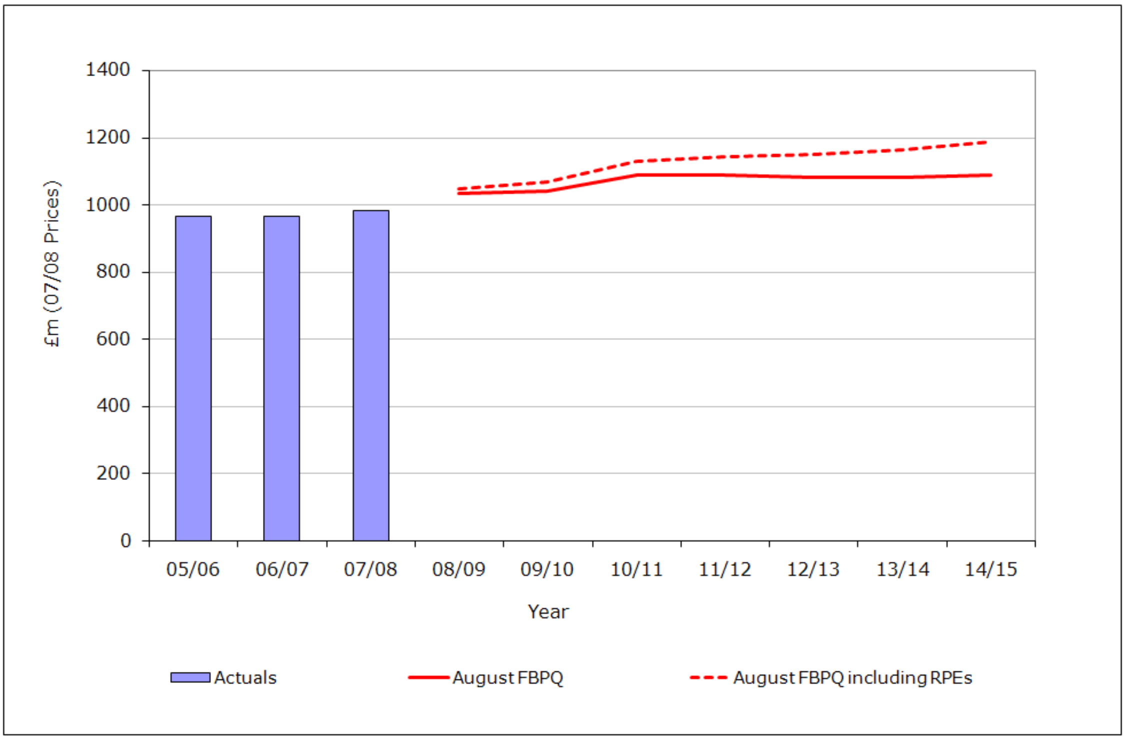


Table 4.5: Actual and forecast indirect costs and non-operational capex by DNO for DPCR4 and DPCR5

£m (07/08 Prices)	DPCR4				DPCR5			Change DPCR4 to DPCR5
DNO	**Actuals**	**Forecast**	**RPEs**	**Total**	**Forecast**	**RPEs**	**Total**	**%**
CN West	236	164	0	400	424	0	424	6%
CN East	231	142	0	374	368	0	368	-1%
ENW	270	183	5	458	505	45	550	20%
CE NEDL	153	107	2	262	272	13	284	8%
CE YEDL	173	118	3	294	304	14	318	8%
WPD S Wales	123	86	1	210	230	8	238	14%
WPD S West	163	109	1	273	309	11	320	17%
EDFE LPN	209	170	4	382	449	34	483	26%
EDFE SPN	205	174	4	383	437	30	467	22%
EDFE EPN	330	285	6	621	717	52	768	24%
SP Distribution	217	126	5	347	326	52	379	9%
SP Manweb	204	125	5	333	334	50	384	15%
SSE Hydro	143	102	3	247	263	15	278	12%
SSE Southern	259	182	5	445	479	32	511	15%
Total	**2915**	**2072**	**42**	**5029**	**5416**	**356**	**5772**	**15%**

4.41. CN and CE forecast small increases in costs in DPCR5 with relatively low increases in input costs. WPD, SP and SSE forecast moderate increases in costs. Both

ENW and EDFE are forecasting large increases driven in part by larger increases in input costs.

4.42. Most DNOs did not include their expected costs for training apprentices over the remainder of DPCR4 and the DPCR5 period in their August submissions and have indicated that these will be included in February. The key exception is ENW who have forecast an increase in training costs of around £5m in from 2010-11. We have undertaken an initial review of the work carried out by the EU Skills and the ENA, which suggests that an additional £158.5m of expenditure (across opex and capex) will be required in the DPCR5 period. This would fund the costs of recruiting and training an additional 9000 new staff split between their own labour and external contractors. We recognise the need to train additional apprentices in the next price control period and will carry out further analysis to ensure that the level of costs is appropriate and to decide how these should be funded.

Incentives and output measures

4.43. The discussions in chapter 1 and actual and forecast expenditure for DPCR5 highlight a number of issues for development of price control incentives. In particular we need to:

- develop mechanisms for managing uncertainty given volatility in economic conditions,
- refine incentives for forecasting and managing actual expenditure so that we receive reliable data as part of the price control review and so that DNOs make sound economic decisions trading off operating and capital expenditure, and
- have enhanced output measures both to assess company forecasts and to ensure that the DPCR5 settlement delivers value for money to customers.

Managing volume uncertainty

4.44. There are a number of options for managing uncertainty in economic growth and its impact on demand and load related network investment including revenue drivers, investment drivers and triggers.

4.45. The current price control includes revenue drivers based on units distributed and customer numbers to manage uncertainty in demand and new connections. We do not consider that these measures adequately capture the relationship between changes in economic growth and costs and the units distributed driver may discourage DNOs from using demand side management (DSM) schemes to defer reinforcement. We therefore propose to remove these drivers in DPCR5.

4.46. In both DPCR4 and TPCR capex drivers were introduced due to uncertainty surrounding levels of generation connection during the period and dealing with volume uncertainty more directly. We intend to extend the use of capex drivers to demand related investment and associated indirect costs where we identify significant uncertainty.

4.47. For example, we may flex connections network investment allowances according to actual volumes of new connections. We may flex general reinforcement expenditure allowances (i.e. expenditure on reinforcing the network due to general load growth which cannot be attributed to a specific customer) based on the increase in demand in MVA at highly loaded substations. We are also considering introducing triggers for high materiality projects. As part of these arrangements, DNOs will need to demonstrate that they have done all they can to manage demand at heavily loaded substations including encouraging DSM and through their charging methodologies.

4.48. Where capex drivers or triggers have been implemented in previous price controls they have included a fixed allowance to fund 'baseline' investment and variable allowances to allow an increase or reduction in investment should volumes outturn differently to those assumed in the baseline. We intend to adopt a similar approach in this review.

Managing input price uncertainty

4.49. DNOs have indicated that increases in real input prices have increased capex spend by up to 20 per cent in DPCR4. However, in recent months there have been sharp reductions in commodity prices. For example, the price of copper rose from around £2,000 per tonne at the beginning of DPCR4 to over £4,000 per tonne in 2006. Since then there has been significant volatility with the latest prices at approximately £2,300 per tonne.

4.50. In principle such changes in input prices are a risk faced by the DNO as there is no reopener for input prices or any form of indexation included in the current control. In practice DNOs are given significant protection through the capex rolling incentives (they only bear between 29 and 40 per cent of the increases) and have also managed higher input prices by varying the volumes of activity to keep their overall level of expenditure within the cost allowances. However, there will be less opportunity for DNOs to manage price risk in this way as we introduce additional outputs measures for DPCR5.

4.51. A key issue for DPCR5 is how much input price risk should be placed on customers relative to shareholders. There are advantages in setting a fixed ex-ante allowance for changes in input prices as this provides strong incentives for DNOs to manage costs where they can, for example through effective procurement, purchasing in advance or hedging some of the risks. However, given the current volatility in input prices it is difficult to set a robust forecast for DPCR5 and there is a danger that we either set prices at the peak resulting in a loss to consumers or set prices significantly too low resulting in a loss to shareholders.

4.52. There are advantages in using some form of indexation whereby our allowance for input prices would track market indices for input costs. A difficulty with this approach is that it may reduce DNOs' incentives to manage costs if they choose to minimise their risk by matching the indices. There are also practical issues in terms of determining an appropriate index. There is no ready-made index for electricity distribution input prices and it would be necessary to determine appropriate weightings to combine other broader indices.

4.53. We consider that it may be appropriate to set an ex-ante allowance for input costs and expose DNOs to price risk up to a certain trigger level of change in prices. Beyond this we would apply indexation for the protection of both customers and shareholders.

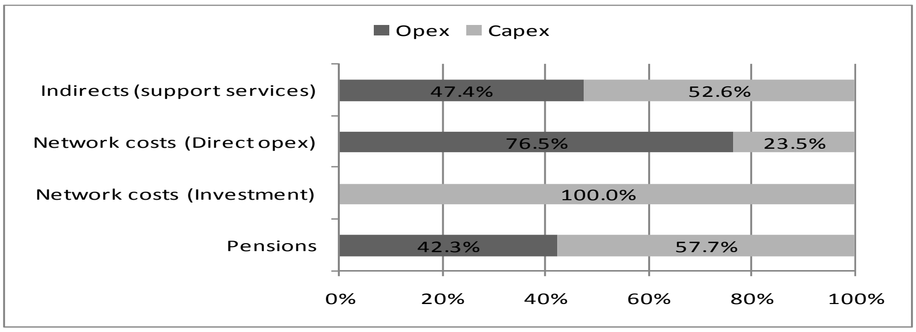
4.54. We would welcome views on the appropriate approach to managing uncertainty associated with input prices. Should we set an ex-ante allowance based on a forecast increase in input prices, introduce indexation or adopt a hybrid approach whereby indexation is introduced above a certain threshold?

4.55. We developed our forecast business plan questionnaires (FBPQs) in such a way that we separate out changes in costs due to underlying variations in volumes of activity and efficiency from changes in real input prices. This gives us a better understanding of the reasons for forecast changes in expenditure and allows us to identify elements of the forecasts that are more uncertain. We consider that the Information Quality Incentive (IQI) mechanism should exclude the impacts of changes in real input prices. It will then only reflect differences in forecasts for the underlying volumes of work that are needed on the network to deliver appropriate outputs rather than differing forecasts for input prices. An allowance for input costs can then be added in after the incentive has been applied.

Equalising incentives

4.56. There are currently imbalances between in the incentives for costs that are classified as opex and costs that are classified as capex under the DPCR4 RAV rules. These imbalances may distort real economic trade-offs between capex and opex solutions and create boundary issues. DNOs bear the full cost if they spend £1 of additional opex but only 29p to 40p if they spend £1 of additional capex. The diagram below sets out the proportion of costs that are capitalised to RAV for each of the groups of activities under the current cost reporting rules.

Figure 4.6 Capitalisation of costs for different activities



4.57. DNOs benefit if more direct operating costs (such as tree cutting, fault costs, or inspections and maintenance) are classified as network investment or indirect costs, because this moves costs out of an area with stronger incentives and into an area with weaker incentives.

4.58. The balance of incentives is particularly important in the context of forecasts for large increases in opex and capex. We are looking to ensure that DNOs have given appropriate consideration to innovative solutions including potentially deferring greater volumes of work and doing more to actively manage and monitor levels of risk or adopt non-network solutions such as demand-side management or contracting with distributed generation to manage constraints.

4.59. A significant amount of our resources during the DPCR4 period have been spent monitoring the boundary between various categories of costs, for example the distinction between fault costs and asset replacement or the treatment of site engineer costs. Equalising cost incentives could reduce the reporting burden for both the DNOs and Ofgem. It may also lessen concerns with definitional issues, which would allow the regulatory reporting pack (RRP) to be less resource intensive to complete and review.

4.60. We are considering a number of potential options for moving towards more equal incentives:

- We could treat the costs for all activities the same way and capitalise the same percentage of all costs into the RAV. This would remove the costs boundaries and reduce any distortions to the economic trade-offs we are encouraging DNOs to make. It may be appropriate to apply the IQI mechanism to all costs.

- We could treat all direct costs, engineering indirect costs, networks investment support costs and any constraint payments (e.g. DSM or payments to DG) in the same way. A fixed proportion of all such costs would be allocated to RAV but business support costs would be fully expensed. This may capture the key economic trade-offs and significantly reduce boundaries but there may be some distortions remaining under such an approach.

- We could identify where the key trade-offs are between activities such as faults and asset replacement and ensure that such costs are included in the RAV using the same fixed percentage. This would reduce but not remove all boundary issues.

4.61. There are a number of issues which need further consideration under these approaches. For example, under the first two options we would need to decide the appropriate portion of costs to capitalise and what impact this may have on financeability, appropriate regulatory asset lives and depreciation.

4.62. There have been mixed views to-date from the DNOs on this issue. While some DNOs supported moving towards greater equalisation of incentives, others have suggested that further work is needed to resolve issues with the IQI mechanism before this is taken forwards. Others noted concerns about potentially weakening the strength of opex incentives. We welcome your views on each of these options and which approach you consider should be adopted.

Information quality incentives (IQI)

4.63. In recent price controls, including DPCR4 and GDPCR, we introduced a number of refinements to the RPI-X framework to address issues of variations in the strength of incentives throughout the price control period and risks associated with companies earning high returns through submitting high capex forecasts and then significantly underspending these forecasts.

4.64. The IQI places more weight on DNOs' forecasts in setting allowed revenues, whilst encouraging them to forecast expenditure at more realistic levels. Given the assumption that management and shareholders are risk-neutral, DNOs earn the highest income by accurately forecasting their intended capex. We consider that the IQI was beneficial in terms of encouraging both EDFE and SP to submit revised forecasts at DPCR4, reducing capex by approximately £200m. However, we have concerns that some of the other DNO groups who submitted relatively high forecasts at DPCR4 have spent significantly less than their allowances to date and may outturn significantly below their allowances by the end of the period.

4.65. Responses to our consultation documents and other papers have highlighted two main issues with the IQI mechanism. Management may be risk averse and looking to protect themselves against increases in costs. This may lead to DNOs forecasting higher than their actual view of their cost requirements. Giving companies' complete freedom to reforecast through successive FBPQs may undermine the IQI incentives. A DNO may submit a high forecast at an early stage to influence Ofgem's baselines and then submit lower forecasts to benefit from higher cost incentive rates and cash rewards under the scheme.

4.66. We consider there have been significant benefits to customers from applying the IQI to date and will continue to apply this mechanism as part of DPCR5. However, there may be scope for further improvement in this approach, both in terms of the coverage and the effectiveness of the incentives.

4.67. We have decided to place limits on the ability of DNOs to update their forecasts later in the price control process, similar to those set out by Ofwat. After initial proposals, DNOs will be allowed to update their forecasts on the basis of new evidence or significant changes in outputs, or scope of work, but we will not allow wholesale changes to the forecasts. Companies will have to provide detailed explanations of changes to their forecasts. This approach means that it is critical that DNOs do all they can to ensure that the February submissions reflect their best forecasts possible.

4.68. We are also considering options for sharpening the IQI to deal with issues of risk aversion and to provide protection against the risk of major over or underspends. We are considering introducing deadbands or weaker incentives around the allowance to address concerns that the companies that forecast closest to our view stand to bear the highest percentage of any overspend. A more detailed discussion of the IQI and potential changes to it is set out in appendix 9.

Output measures

4.69. In the first consultation document we highlighted the current lack of output measures and in particular those relating to asset driven investment. The need to develop good output measures is driven by a number of key requirements including the assessment of efficient investment requirements, for DNOs to improve the way they plan and operate the networks with a focus on the outputs that will be delivered and to ensure that the DPCR5 settlement provides value for money to customers.

4.70. The outputs presented must be:

- measurable, controllable, auditable and replicable over time,
- aligned with the underlying business processes that are used to plan and operate the network,
- cover the major areas of network investment and network operating costs. As a minimum the outputs must address general reinforcement and condition based asset replacement, and
- where possible capture outputs or outcomes such as performance, asset health, network capacity or headroom or network risk and as a last resort inputs such as the volume of asset installed.

4.71. DNOs must be able to show how the outputs would vary with changes in expenditure and the trade-off between different outputs. Examples of output measures are set out in table 4.6 below.

Table 4.6 Examples of output measures

Area	Outputs
Overall customer performance	Number and duration of interruptions Overall customer satisfaction
Load related spend	Number of connections made Composite risk metric capturing numbers of customers at risk, time at risk, capacity headroom and extent of load growth Overall network loading
Asset replacement	Composite metric capturing asset condition and criticality Asset fault rates Modelled percentage remaining life
Flooding	Number of substations with improved flood mitigation

4.72. Given the current stage of development of output measures in distribution it is more practical for DPCR5 to have a common framework for the development of outputs but with each DNO able to develop its own set of company specific outputs for areas of investment where the industry has been unable to agree a common approach. For general reinforcement and condition based asset replacement Ofgem will be working closely with all the DNOs to try and develop the basis for a common set of outputs.

4.73. In the longer term it would be desirable to develop a common set of outputs across all the DNOs similar to the approach being used in the Transmission output measures project.

4.74. Any company specific outputs must meet all the requirements set out paragraph 4.70. The high level FBPQ responses and narrative provided by the DNOs in August did not adequately address this requirement. If companies do not provide sufficient output information as part of their FBPQ they are likely to find it more difficult to convince us of their cost forecasts. For example, where there is insufficient output information we will place more emphasis on high level benchmarking or undertake a more detailed review of forecast expenditure and/or individual projects. We are also considering whether, if a company is unable to provide an adequate range of measurable outputs, we should be seeking to constrain their ability to outperform against the weighted average cost of capital (WACC) or to take other measures to reflect the greater scope that company will have to increase shareholder returns at the expense, for example of network condition. In such cases it may be appropriate to apply a different IQI matrix, for example, with lower powered incentives and retain the option of an ex-post review.

4.75. We would welcome views on what action we should take with DNOs who provide insufficient output information as part of their FBPQ.

4.76. As discussed in chapter 1 we intend to explicitly include a wider range of output measures and associated targets as part of the licence conditions underpinning the DPCR5 settlement. This will include requirements for annual reporting of performance against the outputs. In addition it may be appropriate to introduce some form of independent audit of the DNOs' output metrics.

4.77. We would like, as a matter of principle, wherever possible to agree ex ante mechanisms to adjust allowed revenues according to performance against the outputs but where we have new output measures this may not be possible and we may have to revert to ex post reviews where outputs are not delivered. As long as a DNO provides accurate forecasts at DPCR5 and meets the agreed outputs any underspend against allowances should then be the result of a true efficiency saving.

Cost assessment methodology

4.78. One of the key benefits of the cost reporting work that has been carried out in this period is that we now have much more robust data on which to base our cost assessment analysis. In parallel with this we have also carried out work to improve the quality of the benchmarking and investment modelling work.

Comparative analysis work

4.79. We have broadly grouped direct operating costs, engineering support and business support activities into two categories. Those where statistical techniques such as regression analysis are appropriate and others where other techniques such as bottom-up analysis or expert review are more appropriate. The latter includes road occupation costs, insurance, IT and property management.

4.80. We have undertaken extensive work to understand the main cost drivers for each of the activities we are looking to include in our statistical analysis and to consider any adjustments that should be made prior to benchmarking. We have then used this to guide our view of those activities that we should group together for benchmarking purposes.

4.81. We have been discussing our approach to the cost benchmarking with a number of academics as well as the DNOs and are looking to develop the range of techniques we are using in line with best practice for other regulators taking into account the availability of data. These techniques include corrected ordinary least squares (COLS) regression, panel data techniques, use of international data and Data Envelope Analysis. We will carry out benchmarking at both a top-down and more disaggregated level.

4.82. Further details are set out in the appendix 8.

Assessment of investment requirements

Asset replacement

4.83. We now have sufficient resources in-house to review DNOs' forecast asset replacement and have developed our own capability to carry out age-based investment modelling and to assess the approaches used by the DNOs. We have developed a range of techniques to better estimate asset lives based on the information available to us. We intend to use our age-based models as a starting point to sense check and better understand the DNOs forecasts. Where they forecast significantly higher or lower capex volumes than our benchmarked model output they will need to justify their differences on the basis of sound asset management techniques such as condition based replacement forecasting and be able to quantify the outputs associated with the asset replacement.

Load-related investment

4.84. For load-related expenditure (LRE), given the decline in growth of units distributed over recent years, the main drivers of load-related investment tend to be new connections and areas of above average load growth and particularly large one-off connections. We have therefore had to adapt our models so that they focus on those parts of the network which require reinforcement due to higher loading and/or higher than average load growth. We are also considering appropriate investment drivers for demand triggered connections and triggers for high materiality general reinforcement projects. Further details are set out in appendix 8.

Next steps

4.85. Over the next few months we will be continuing to develop our approach to benchmarking and investment modelling as well as carrying out the analysis itself. We will also be reviewing the February 2009 FBPQ submissions. In early May we will be publishing a consultation document setting out our latest methodology for the cost assessment work and our initial results.

5. Financial issues

Chapter summary

This chapter considers: our approach to calculating the cost of capital and regulatory asset values, financeability, financial modelling, the treatment of taxation, and pensions. In developing our policies in this area we will take account of our duty to consider the need for efficient DNOs to be able to finance their activities in carrying out their statutory and licence obligations. We will aim to provide strong financial incentives for companies to identify and make efficiency savings and to enable customers to share in the benefits from any savings over time.

Question 1: Have your views on the appropriate methodology for setting the cost of capital or on indexing the cost of debt changed as a result of the current turmoil in the capital markets?
Question 2: What is the appropriate timing of actuarial valuations for setting ex ante pension allowances (see also appendix 10)?

Cost of capital

5.1. The cost of capital is an important component of the review as it determines the rate at which DNOs' RAV is remunerated. But it constitutes only one of the factors that drive the overall financial performance under a price control; the various incentive schemes in the price control enable well run, efficient DNOs to outperform the settlement and earn above their allowed cost of capital over the period of the review[40]. For DPCR5, we are proposing to recognise this more explicitly and to view the settlement more holistically to avoid too narrow a focus on the cost of capital decision. This will involve setting the cost of capital and all of the various incentive arrangements to determine an appropriate range of potential returns that a company will be able to earn from the package as a whole. The weighted average cost of capital (WACC) will be only one of several components in that assessment.

The current economic climate

5.2. During the past few months, capital markets have seen great uncertainty and volatility. Debt markets have been especially affected as reduced capital availability and concerns over creditworthiness have reduced liquidity. This has, on occasions, limited the availability and raised the price of debt instruments even for network companies that have traditionally been viewed by the markets as relatively low risk. The package recently put together by the government coupled with significant

[40] As an indication of its relative importance, a 10 basis points reduction in the allowed weighted average cost of capital (WACC) in DPCR4 would have resulted in a 0.60 per cent decrease in revenues for all 14 DNOs for the 5-year duration of the price control.

reductions in interest rates by most major central banks are expected to improve liquidity in the market and lower the cost of debt from current levels. But at the time of publication companies are still reporting difficulties accessing the debt markets on a consistent basis and are also reporting significantly increased rates for both short term and long term debt issuances relative to the prices they were paying before the current credit squeeze began.

5.3. Compared with the wider economy and other companies, the electricity distribution sector may be relatively insulated and better placed to meet the challenges presented by the current market conditions as (i) with few exceptions the refinancing needs for DNOs are limited during the remaining DPCR4 period and (ii) on average, the structure of DNOs' embedded debt is geared towards fixed rates, thus shielding them from short-term interest rate movements. As a result, DNOs are still generally considered as sound investments and this is reflected in their maintenance of their investment grade credit ratings.

5.4. We note, however, that given the expected increased capex spending in DPCR5, currently estimated at 82 per cent compared to DPCR4 DNOs are likely to need to raise additional finance on both a long term and short term basis in DPCR5.

5.5. Going forward, we intend to continue monitoring closely developments in general and the effect of recent government policy in particular on the availability and cost of debt instruments, in order to assess the duration and depth of the current 'credit crunch'. Our final decision on the cost of capital for DPCR5 will be informed by how the situation evolves during 2009. We will set out our initial views on the cost of capital range during initial proposals in July 2009 and we will publish our final decision in final proposals in December 2009.

Calculation methodology

5.6. Most respondents to our initial consultation maintained that the methodology used in setting the WACC in DPCR4 - which places a greater weight on long-term trends rather than short term movements - remains appropriate and should also be used in DPCR5. Our decision on the cost of capital will also be informed by a relative risk analysis. At this point, we also do not see any advantages in altering substantially our methodology for calculating the cost of debt and equity and we intend to maintain our post-tax approach which requires the tax allowance to be calculated separately.

Cost of equity

5.7. As outlined in the initial consultation document, the limited number of independent publicly-quoted DNOs on the London Stock Exchange presents a significant challenge for the calculation of the beta[41] and as a result we intend to examine a number of variables to arrive at a cost of equity. We are not in a position at this point to confirm whether the range of long-term average returns of 6.5-7.5 per cent that we used in DPCR4 is still appropriate under DPCR5. We particularly acknowledge that, should the credit crunch prove long lasting, it may have an effect on the cost of equity, which we will take into account in our final decision.

5.8. In the initial consultation we also raised the issue of employing market asset ratios (MARs) as one of the parameters used in setting the cost of equity. While we will keep monitoring MARs as one of a wide range of indicators regarding expectations, we recognise that each transaction has its specific characteristics and thus we do not intend to explicitly factor MARs into our cost of equity calculations.

Cost of debt

5.9. In setting the cost of capital, we have hitherto calculated the weighted average of the expected cost for debt and equity assuming a notional level of gearing ex ante for the entire duration of the price control period. In the initial consultation we raised the possibility of indexing the cost of debt in order to trail actual interest rates more closely. Most respondents argued against the introduction of indexation/triggers. We would welcome additional feedback if views have changed because of current market conditions.

5.10. In deciding the appropriateness of introducing indexation we examined it under three criteria:

- Desirability, i.e. whether it would encourage the kind of DNO behaviour that we would like to promote,
- Practicality, i.e. how easy would it be to construct an appropriate and transparent index, and
- Materiality, i.e. what is the magnitude of the improvement for customers that the introduction of such a mechanism would entail without compromising the ability of companies to finance their activities.

5.11. Our analysis concluded that the ex ante approach provides the appropriate incentive mechanism for DNOs to obtain better rates and put in place an efficient debt structure. Interest rate risk is best managed by DNOs and a transfer of this risk to the consumer via indexation would be sub-optimal. Further, there is no single index that can be universally accepted as representing the cost of debt for DNOs and

[41] In the Capital Asset Pricing Model (CAPM) calculation of the return of equity, the beta coefficient describes how the expected return of a stock or portfolio is correlated to the return of the financial market as a whole.

constructing an appropriate benchmark index would involve a wide range of equally arbitrary assumptions, in addition to being fraught with technical difficulties. The issue of materiality depends heavily on the assumptions used for the construction of the index and in particular the choice of the benchmark, the sensitivity of the index to actual movements in rates, and whether it would be applied only to new debt or also to embedded debt. Overall, although there seem to be some potential benefits, we believe that these are outweighed by de-incentivising DNOs to manage interest risk.

5.12. Our analysis echoes the Competition Commission's conclusion in September 2007 that '… indexation would start to erode one of the core foundations of RPI-X regulation – i.e. that shareholders are asked to manage cost risk for periods of five years at a time – without offering sufficient benefits to justify the apparently sub-optimal allocation of risk'[42].

5.13. Although our 'minded to' position is currently against the introduction of a pure indexation mechanism, we would question whether recent events in the capital markets suggest that it might now be in customers' interest to consider some form of debt trigger/re-opener. We thus intend to retain the option of introducing a cost of debt trigger or re-opener in DPCR5 if when we set the cost of capital, capital markets conditions remain difficult or debt rates remain well above long term averages. Under such circumstances, a trigger/reopener mechanism will enable us to set the cost of capital at a level that will allow companies to finance their activities while current conditions prevail, without penalising consumers with higher charges once actual rates have reverted to their long-term average. A trigger mechanism would mean that there would be a range of cost of debt within which DNOs would manage their interest rate risk while a trigger would be activated once the cost of debt moves outside this range. We consider that should current market volatility persist, this potential benefit could outweigh the difficulties of correctly setting a trigger or a potentially higher degree of uncertainty associated with a reopener. A final decision on this matter will be taken closer to final proposals.

Gearing

5.14. The notional level of gearing used in the calculation of the WACC was 57.5 per cent, 60.0 per cent and 62.5 per cent in DPCR4, TPCR and GDPCR respectively. Given the current volatility in the markets, most respondents to our initial consultation argued that a significant increase to the notional level of gearing could potentially create financeability difficulties for DNOs. However, one respondent pointed out that current market evidence suggests that DNOs can achieve gearing levels up to 70 per cent whilst maintaining an investment grade rating.

[42] A report on the economic regulation of the London airport companies (Heathrow Airport Ltd and Gatwick Airport Ltd), appendix F, www.competition- commission.org.uk/rep_pub/reports/2007/fulltext/532af.pdf

5.15. In line with the other parameters of the cost of capital range, our assessment of the notional gearing ratio of net debt to RAV will be taken at a later stage, although we do not expect a substantial departure from the decisions we have taken recently regarding gearing levels.

Financeability and Financial modelling

5.16. In the initial consultation we raised the issue of whether we should apply financeability adjustments to allowed revenue in order to ensure that DNOs can finance their operations. Most respondents argued that provided the cost of capital is set at the right level, NPV-positive financeability uplifts are unnecessary and should be avoided. This is also our current view.

Accelerated depreciation

5.17. We have previously increased regulatory depreciation rates for English and Welsh DNOs (for some DNOs at DPCR3 and for others at DPCR4) in order to mitigate the effects of the full depreciation of assets held at privatisation. If we had not made this depreciation adjustment, this post vesting 'cliff face' would have significantly depressed DNOs' allowed revenues and impacted on their financeability. This adjustment of regulatory rates has brought regulatory depreciation rates out of line with accounting rates with potential adverse implications in the future if asset replacement reaches a steady state. As outlined in our initial consultation, in DPCR5 we might consider re-setting depreciation rates for the RAV. Any decision, however, will be informed by financeability issues as well as our final proposals regarding the calculation of the RAV.

5.18. Because of different vesting times and rates, the two Scottish DNOs did not reach the cliff face in DPCR4 but will do so in DPCR5 and we will take this into account when we set the deprecation rates applicable to them.

Financial modelling

5.19. We have sent DNOs the first draft of the financial model we propose to use for DPCR5 for their feedback and we are currently processing their comments. As we stated in the initial consultation we believe it is important that the price control is a transparent process. We intend to publish an aggregate DPCR5 financial model for all 14 DNOs at the beginning of 2009 and the fully populated model together with our final proposals, as we did for GDPCR.

5.20. In our initial consultation, we also raised the issue of whether the three key financeability ratios used in DPCR4 (FFO[43]/interest, retained cash flow/debt and average net debt/average RAV) remain relevant indicators of financeability. We have discussed the issue with the rating agencies and we remain confident that this is indeed the case. We also intend to incorporate and monitor a number of additional ratios in our financial model, such as FFO/net debt and closing net debt/closing RAV.

Profiling

5.21. In DPCR4 we smoothed revenues over the five-year period in order to reduce the volatility of the charges paid by consumers. In GDPCR revenue profiling was not applied as a cost-reflective price structure was deemed to be more appropriate. We consulted on this issue in our initial consultation and received mixed responses. We intend to make a final decision on profiling at a later stage of the price review process, taking into account the benefits of cost reflectivity but also the potential magnitude of P0 for DPCR5.

Treatment of taxation

Overall approach

5.22. As noted in the initial consultation, we will maintain our approach at the last three price controls for setting tax cost allowances on an ex-ante basis with an ex-post adjustment where actual level of gearing exceeds the gearing assumption underpinning our cost of capital assessment. Under this methodology, DNOs are responsible for managing tax risk and for the duration of each review period retain the benefit of any tax cuts or bear the extra burden of tax rises.

Triggers

5.23. In initial consultation we sought views on capping the tax incentive through the introduction of a sharing mechanism for ex post adjustments for specific changes in the tax regime and legislation that is outside the control of DNOs. Respondents expressed mixed views on the issue of a sharing mechanism. In subsequent discussions with DNOs there was broad agreement that this was favoured but only for changes in the tax regime outside the control of licensees, such as changes to the corporation tax rates or to the rate of tax relief for capital expenditure. It is noted that the net effect of the tax regime changes introduced in April 2008 resulted in a windfall for DNOs for the last two years of DPCR4. This gain is estimated to be equivalent to a 60 basis point increase for each year of the DPCR4 period in the return on regulatory equity. We intend to keep the option of a sharing mechanism open, possibly subject to a trigger to avoid adjusting for relatively immaterial

[43] Fund flows from operations.

changes. Should we decide to implement such a mechanism, this is likely to be symmetric (i.e. for both tax rate cuts and increases) and be activated once an explicit materiality threshold is reached.

5.24. An alternative approach to the trigger would be to pass through any changes in tax costs. We consider this approach would disincentivise DNOs to manage their tax costs efficiently and bring little potential benefits to consumers. In addition such a mechanism carries a number of practical issues relating to the fact that tax liabilities are closed with Her Majesty's Revenue & Customs (HMRC) and settled some years after the year to which they relate. Annual payments may be distorted because of this and extracting tax payments related to non-distribution activities would be an added complication.

Claw back of tax benefits of excess gearing

5.25. As indicated in the initial consultation we intend to maintain the ex post adjustment which claws back from licensees the revenue benefit they obtain from lower tax costs where both the gearing assumption and interest costs have exceeded those modelled at the relevant price control. As this adjustment is also applicable to transmission operators and gas distribution licensees in their respective price controls we are publishing in parallel to this document a separate letter on this issue for DNOs, GDNs and TOs. The letter outlines our proposal on how to tackle a number of practical issues not specifically addressed at the respective price controls, arising from developments in financial reporting and financial engineering.

Modelling of capital allowances

5.26. In the initial consultation we indicated that in modelling the categorisation of capital expenditure to the main capital allowance pools we would maintain the generic approach consistent with DPCR4. That basis did not necessarily result in capital allowances that mirrored DNOs' own capex profiles and attributions in application of the tax rules.

5.27. Historically, we have adopted different approaches across our price controls, influenced by data availability across both time and licensees and the materiality of our assessment of tax charges. At DPCR4 we adopted a generic approach, rather than actual, to allocating capex to individual tax pools as our primary criterion was for consistency across DNOs. At GDPCR and TPCR4 we used actual allocations but the circumstances were different. For TPCR4 there were few companies and consistency across time within a licensee was the main criterion. In GDPCR there was a lack of tax history following the sale of GDNs by National Grid.

5.28. Going forward to DPCR5 there are three distinct options for the allocation of expenditure into the various tax pools:

- The generic approach, which involves using our view of how this allocation should be made:

- The common approach, which relies on an 'average' actual allocation based on the information we receive from the DNOs, and
- The specific approach, which uses the actual DNO-specific tax pool allocation policy.

5.29. We have reviewed our approach following discussions with the DNOs and have collected additional data to enable us to evaluate moving closer to their own allocations based on their own underlying capex profiles. We consider that the application of the capital allowance rules should in theory result in a consistent approach. In practice, we recognise that for historical reasons there are variations in treatment of similar items. We are minded to revise our methodology to follow, where practical, the common treatment to attributions followed by DNOs, which should more closely reflect their own treatment. Compared to the generic approach used in DPCR4 we do not expect this revision to have a significant impact on tax allowances.

5.30. With the exception of one DNO, our initial analysis indicates that the divergence of DNOs' actual allocation policies from the common allocation percentages proposed is limited (normalising for different capex programmes, the resulting tax allowances are between minus 9 per cent and plus 5 per cent compared to what they would have been if the company specific approach was followed). In one case, the tax allocation policy followed is, for historical reasons, significantly different from other DNOs. In this case we may apply the specific approach which more closely matches that DNO's own attributes.

Regulatory asset value

Finalising DPCR4 RAV

5.31. Following consultation with the Energy Networks Association (ENA) we are working to crystallise all the outstanding matters of interpretation and treatment of DPCR4 expenditure for the purposes of calculating the RAV. We have sent guidelines to all DNOs on how these should be treated.

5.32. In the initial proposals we will provide the methodology on the computation of DPCR5 RAV. This methodology will depend on the approach taken in determining the RAV. In particular, should capex and opex incentives be equalised we expect that the calculation of the RAV to be significantly simplified - see chapter 4.

Revenue adjustment

5.33. In the initial consultation we indicated that in the event that actual 2004-05 RAV additions turned out to be materially different to the estimate of RAV additions used for that year in setting revenues, where the difference was not due to genuine efficiencies we may decide to claw-back the benefit of any under-spend relative to the estimate used. We have reviewed the position and no adjustments are required.

Treatment of excluded services

5.34. We indicated in the initial consultation that we were minded to consider other methodologies to deal equitably with excluded services costs and revenues from the DPCR4 methodology. We will review this as part of the methodology for determining RAV additions in DPCR5, with the overriding objective that customers are not adversely affected. Decisions in this area will be also affected by the approach we decide to take regarding allowing regulated margins for connections - see chapter 3.

Treatment of pensions

Cost of pensions

5.35. Pension costs represent 7 per cent of total allowed DPCR4 revenue. In the first three years of DPCR4 actual pension costs were 11 per cent of total costs, excluding pass-through and tax; and the forecast outturn pension costs are £1.3 billion compared to allowance of £1.2 billion (all in 2007-08 prices) for DPCR4. Looking forward to DPCR5 and the current capital market uncertainty, pension costs and deficit repair payments are expected to increase substantially. DNOs' current forecasts for DPCR5, which exclude any increase over known deficit repair costs, are £1.5 billion.

5.36. We also note that the pension schemes for DNOs, GDNs and TOs are characterised by varying contribution rates and funding levels (see tables below). This has contributed to our concerns as to whether the principles are working and to review whether it continues to be appropriate to accept all the assumptions used by scheme actuaries when we set price control allowances.

Table 5.1: GDN actual funding rates

Licensee (scheme)	NGG	NGN	Scotia	WWU
Future accrual contribution rate	31%	31%	37%	39%
Past accrual funding level	97%	85%	77%	82%

Table 5.2 TPCR4 actual funding rates

Licensee (scheme)	NGGT	NGET	SPT	SHETL
Employer contributions	30.2%	20.6%	23.0%	25.0%

Table 5.3 ESPS/principal Scottish schemes
Electricity distribution contribution rates over time

	Last valuation	04-05	05-06	06-07	07-08	08-09
CN West	31-Mar-07	18.1%	16.7%	16.8%	16.8%	23.1%
CN East	31-Mar-07	15.5%	16.9%	16.8%	16.8%	23.1%
ENW/UU	31-Mar-04	17.6%	20.2%	20.2%	20.2%	20.2%
CE NEDL	31-Mar-07	13.6%	20.6%	20.6%	20.6%	26.3%
CE YEDL	31-Mar-07	14.0%	20.6%	20.6%	20.6%	26.3%
WPD S Wales	31-Mar-07	13.9%	18.5%	18.5%	18.5%	21.1%
WPD S West	31-Mar-07	13.9%	18.5%	18.5%	18.5%	21.1%
EDFE LPN	31-Mar-07	17.3%	18.3%	18.3%	18.3%	20.2%
EDFE SPN	31-Mar-07	17.3%	18.3%	18.3%	18.3%	20.2%
EDFE EPN	31-Mar-07	17.3%	18.3%	18.3%	18.3%	20.2%
SP Distribution	31-Mar-06	15.0%	15.0%	15.0%	15.0%	15.0%
SP Manweb	31-Mar-07	14.1%	14.1%	15.8%	15.8%	20.3%
SSE Hydro	31-Mar-06	20.0%	20.0%	23.8%	27.5%	27.5%
SSE Southern	31-Mar-07	19.9%	19.9%	20.6%	20.6%	23.4%

Pension consultation process

5.37. As indicated in the initial consultation document, we launched a separate consultation to review the working of our pension principles. The background to this consultation is outlined in appendix 10. During the consultation we asked three general questions:

- Have we identified the key issues with the current pension principles?
- Do the principles need amending, and if so, what changes are required?
- Which issues should be addressed as part of DPCR5 and which issues are better dealt with as part of the RPI-X@20 review?

5.38. Following the publication of the Price Control Pension Principles Consultation Document[44] on 7 August, we received and analysed the responses of stakeholders. These are available on our website[45] and are summarised in appendix 10. We also organised a workshop on 8 October providing an additional opportunity for interested parties to express their position.

[44] Price Control Pension Principles ref 120/08
[45] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=98&refer=Networks/ElecDist/PriceCntrls/DPCR5

5.39. Ofgem does not have the power to, nor do we seek to, direct the trustees of pension schemes to make any particular decisions or take any particular actions in relation to company pension schemes. The management of the companies, in conjunction with the scheme trustees, are – and will continue to be - free to make their own decisions on pensions and their other costs. Our consultation was looking at the financial incentives we place on the network companies' management and ultimately shareholders to manage these costs effectively to protect consumers' interests.

5.40. In summary, respondents agreed that the key issues were identified and that our Pension Principles[46] remain appropriate and generally work well. We think it is appropriate to carry out further work to reassure stakeholders and customers that the companies are meeting the principles rather than looking to change the overall principles. In addition to these wider questions, the pensions consultation document raised a number of application issues. A summary of these and the current position is set out in appendix 10.

5.41. One of these application issues concerns identifying the appropriate timing of actuarial valuations. Following receipt of the responses we have expanded the number of options available to include a re-opener. These options are set out in appendix 10 under the 'Appropriate actuarial valuation for setting price control allowances' section. We invite views on which option is considered appropriate.

5.42. In ensuring that our first Pension Principle '*Efficient and Economic Employment and Pension Costs'* is adhered to, most attendees at our workshop on 8 October 2008 accepted that there is need for greater transparency of the pension costs and the actions network companies have undertaken to manage them. We intend to issue a further data request to companies to enable us to make the relevant comparisons and to improve transparency.

5.43. The Pensions Act has received the Royal Assent and will introduce some significant changes. We are currently examining the potential consequences for the price control review.

[46] Developing Network Monopoly Price Controls May 2003 (54/03)
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=41&refer=Networks/Policy

6. Process and timetable

Chapter summary

This chapter outlines the proposed content and dates for our key publications during the remainder of the distribution price control review. It explains how we have and will continue to consult with key stakeholders, including DNOs and the new Consumer Challenge Group. The chapter also summarises the key findings from the lessons learnt exercise for the gas distribution price control review and explains how we will address these for the DPCR5 review.

Question 1: We invite views on which format stakeholders would find most useful for the Ofgem workshops to be held in January 2009.
Question 2: We invite views on our proposed process.

Introduction

6.1. The initial consultation document outlined our proposed process for DPCR5. This chapter provides further detail on the process including some new proposals. We intend to maintain a transparent, consultative process and to provide a clear rationale for the decisions that we take during the review.

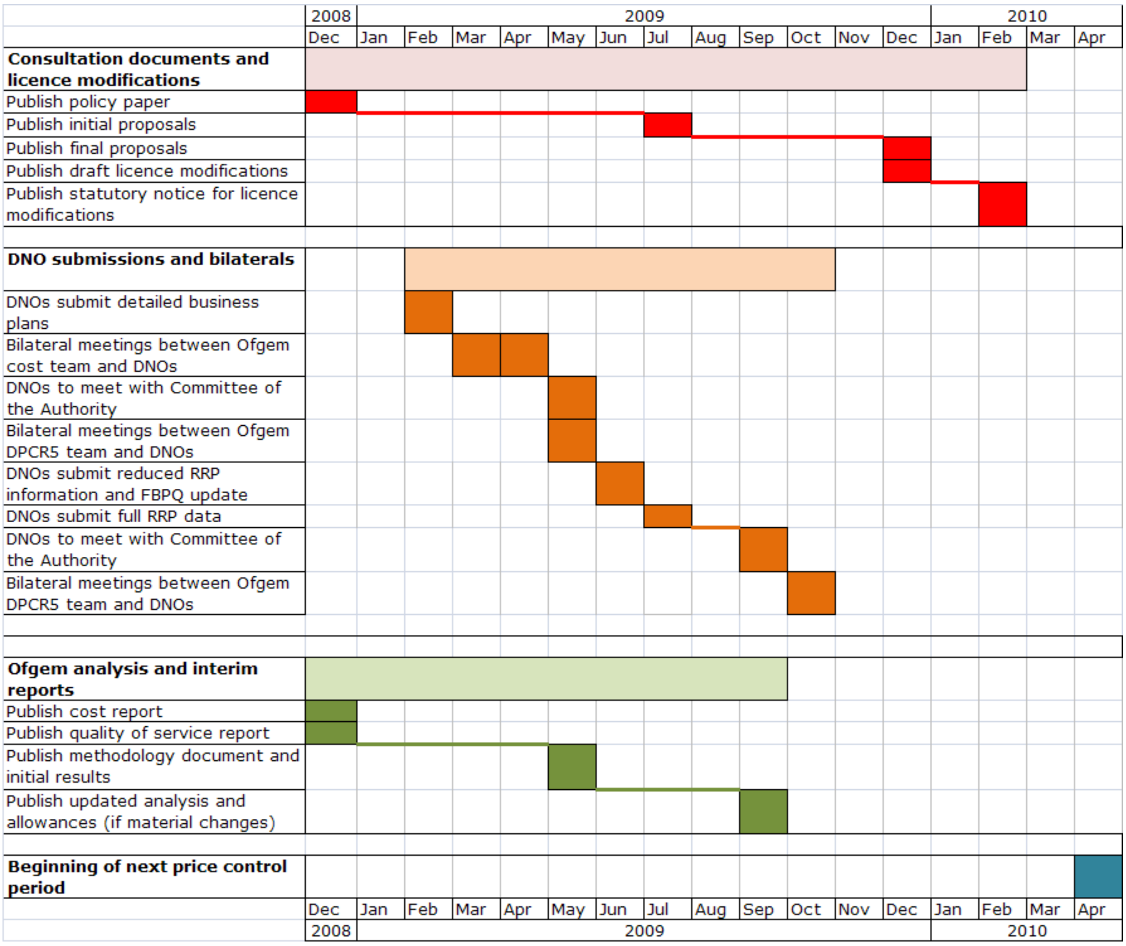
Timetable

6.2. An updated timetable for the remainder of the DPCR5 process is set out in the following table and is shown in the diagram below (figure 6.1).

Table 6.1 - Updated timetable for DPCR5

2008	
December	**Publish policy paper** **Publish cost report** **Publish quality of service report**
2009	
January	
February	DNOs submit detailed business plans (13 February) Consultation closes for policy paper (13 February)
March/April	Bilateral meetings between the Ofgem cost team and the DNOs
May	**Publish methodology document/initial results** Second round of Bilateral meetings between the Ofgem cost team and the DNOs (if required)
June	DNOs submit reduced RRP information and FBPQ update (26 June)
July	**Publish initial proposals (late July)** DNOs submit full RRP data (late July)
August	
September	Publish updated analysis and allowances (if material changes from initial proposals)
October	
November	
December	**Publish final proposals** **Publish draft licence modifications**
2010	
January	
February	**Publish statutory notice for licence modifications**
March	
April	Beginning of new price control period

Figure 6.1 - Timetable for DPCR5



Consultation documents

6.3. We plan to maintain the proposed structure of four main consultation documents for DPCR5. The initial consultation in March 2008 and this policy paper will be followed by initial proposals and final proposals documents.

Policy paper

6.4. This document presents initial recommendations for key policy areas and is based around the three main themes of environment, customers and networks with a separate section discussing financial issues.

6.5. This document will be issued for a ten week consultation period which will allow interested stakeholders time to consider their views and to provide detailed responses on the proposals outlined. We consider that a ten week consultation period is sufficient to allow stakeholders to submit a detailed level of response, taking account of the Christmas break. We have shorted the consultation period slightly from 12 weeks to allow the responses to feed into our analysis at a sufficiently early stage. This will inform an additional consultation paper for publication in May 2009 that will summarise our cost assessment methodology and initial results. Further details about this document are outlined below (paragraph 6.23).

6.6. A summary of the responses to our initial consultation document is provided in appendix 5.

Initial proposals

6.7. We intend to publish our initial proposals document in late July 2009. This document will set out our initial views on allowances and provide ranges on the relevant incentives. It will contain a substantive set of proposals for policy issues and include final impact assessments. The document will also include draft licence modifications where possible.

6.8. We will receive further RRP and FBPQ data from the DNOs before we publish initial proposals but this information will not be included in the document. We will undertake analysis of this data following publication of initial proposals. If this analysis results in material changes or it has a significant impact on our proposals then we will publish a document in September 2009, providing updated allowances.

Final proposals

6.9. We intend to publish our final proposals document in December 2009 as outlined in the initial consultation document. This document will present our final proposals on all outputs and incentives as well as our final views on allowances, RAV roll forward and cost of capital.

Ofgem-led workshops

6.10. We consider that the workshops held in May 2008 were a success. We received positive feedback from the majority of attendees who felt that the content and structure were useful in both providing information and encouraging debate. We are keen to ensure that stakeholders are given further opportunity to participate in a workshop if they wish. We are interested in views on how we can best achieve this.

During consultation period (January 2009) - as previous

6.11. We could maintain the same format as the previous workshops. This would involve presentations from Ofgem and each DNO, with the option for further presentations from other stakeholders. We could hold roundtable discussions as before based on the main topics of the policy paper.

During consultation period (January 2009) - stakeholder focus

6.12. Another option would be to tailor the workshops to cater primarily for non-DNO stakeholders. This could involve Ofgem providing guidance and clarity on the proposals outlined in our policy paper.

6.13. Each DNO could be invited to present on the stakeholder engagement undertaken, the outcomes of this work and how their plans have taken stakeholder views into account. We could have roundtable discussions based on specific proposals/options. This would allow us to reach a wide audience and inform responses to the policy paper.

6.14. We invite views on which option would be most useful for stakeholders or any alternative suggestions on how best to run these workshops.

Consumer Challenge group

6.15. We have established a Consumer Challenge Group as outlined in the initial consultation document. The intention of the Group is to act as a 'critical friend' to Ofgem and to ensure that the consumer perspective is considered throughout the DPCR5 process. We will examine how the Consumer Challenge Group works through the price control review and may look to roll this out to further projects in the future.

6.16. We have held a series of four meetings with the Group so far, the penultimate of which involved the group meeting the Committee of the Authority.

6.17. The Consumer Challenge Group have focussed on a number of specific areas that they are most interested in. These include:

- the consumer research,

- worst served customers,
- measures of customer satisfaction,
- connections,
- losses,
- the impact of environmental issues on the DNOs, and
- output measures.

6.18. Discussions with the Group have helped to inform the development of our views and we have incorporated their views into our proposals where we consider appropriate. We will continue to meet with the Consumer Challenge Group during 2009 and they will also meet with the Authority ahead of initial and final proposals. The Group has an important role to play in promoting the consumer perspective and in challenging our proposals on consumers' behalf. The Group differs from the Consumer First Panel as the group members are experienced in the energy field and so can provide advice and input on more complex issues.

6.19. We are considering whether the Consumer Challenge Group should have a roundtable meeting with the DNOs to discuss the Group members' key areas of interest. Further detail on the composition and terms of reference for the Consumer Challenge Group is contained in appendix 13.

Consumer First Panel

6.20. In October 2008 Ofgem set up the Consumer First Panel, of 100 domestic customers, recruited from five locations across Great Britain. The Panel will meet three times a year to improve Ofgem’s understanding of what matters to domestic consumers and to increase genuine consumer contributions into Ofgem’s policies. We are considering whether it is appropriate to make use of this panel for DPCR5 in 2009 and how this could complement our work with the Consumer Challenge Group.

DNO submissions

6.21. The DNOs will be required to submit detailed business plans for the DPCR5 period to Ofgem by 13 February 2009. This should take into account discussions held with the Ofgem cost team to date, the outcomes of their stakeholder engagement exercises and the proposals put forward in this policy paper.

6.22. We plan to publish non-confidential aspects of these submissions soon after receipt. We will then include additional information in our subsequent consultation documents. Further bilateral meetings will be held with each DNO and the Ofgem cost team in March/April 2009.

Methodology initial results – May 2009

6.23. In May 2009 we intend to publish an update paper showing the initial results of our benchmarking work and our analysis of the business plans submitted by DNOs.

This will provide clarity on progress made by Ofgem by outlining the cost assessment methodology we have used and the initial results that it has generated.

Further RRP and FBPQ submissions

6.24. The DNOs will need to submit initial RRP information for 2007-08 and an update on their DPCR5 business plans to Ofgem by 26 June 2009. We expect that the business plans will be robust at this stage, and propose to limit the number of changes that DNOs can make following this submission. DNOs will then be asked to submit full RRP data for 2007-08 by late July 2009.

6.25. We will publish the initial proposals document in July 2009. Ahead of final proposals we would expect to have to make changes to these proposals to accommodate the additional year's actual cost data from the DNOs, the updated business plan figures submitted to Ofgem and any changes in the macro-economy in the second half of the year.

Updated allowances - September 2009

6.26. In the past, we have published an updated proposals document around September to allow consultation on any changes made following publication of initial proposals. For DPCR5 we are keen to limit the number of changes DNOs make to their plans between initial and final proposals and expect DNOs to be able to justify any proposed changes.

6.27. We propose that changes will only be permitted if they are due to additional information received, if there are significant changes to the macro-economy that have a bearing on their forecasts or if unforeseen circumstances arise. Therefore, we do not propose to issue an updated proposals document for DPCR5 unless there are material changes arising as a result of any or all of these factors.

6.28. We are keen to develop our proposals through ongoing discussion with the DNOs and other stakeholders. The DNOs will be invited to meet with the DPCR5 team and the Committee of the Authority between the publication of initial and final proposals. We think that this will be a better use of our resources than working to publish a further consultation document.

6.29. At this time we think that, if we were to publish such a document, it would not cover the full range of issues in the settlement and would only look to provide information on key changes following the publication of initial proposals.

Working groups

6.30. We have set up a number of DPCR5 policy working groups to inform discussion and development of policy proposals. These include dedicated groups focussed on environment, customers and finance which seek to progress work in developing options on policy. These are not forums for gaining customer and other stakeholder views which we have sought to address through Ofgem-led workshops, our consumer research, the consumer challenge group and by encouraging DNOs to undertake their own stakeholder engagement.

6.31. We have sought to use the working groups to enrich discussion and enable development of our proposals and will continue to do so through the remainder of DPCR5. Membership of the working groups consists primarily of DNOs. Other stakeholders have been invited to attend to discuss specific issues if it is felt that they have a particular contribution to make, such as if they have undertaken research on a topic or have submitted a paper. We propose to continue with this format for the duration of DPCR5.

Committee of the Authority

6.32. We held the first round of meetings with the Committee of the Authority in September and October 2008. These allowed each DNO a dedicated opportunity to present their initial views on DPCR5 to the Committee. We intend to hold two further rounds of Committee meetings for the DNOs, to take place prior to publication of initial proposals and final proposals. We consider that the session prior to initial proposals may be more important than in previous reviews, as we intend to limit the changes that DNOs can make to their forecasts between initial and final proposals, unless justified by additional information or arising issues.

6.33. The Consumer Challenge Group met with the Committee in October, and will continue to do so each time that the Committee meets with the DNOs.

Gas distribution price control review (GDPCR) lessons learnt

6.34. Ofgem completed a lessons learnt exercise following completion of GDPCR. This involved an open letter[47] seeking responses from industry and other interested stakeholders. The consultation closed on 30 May 2008 and non-confidential responses are available on our website[48].

6.35. The findings of the GDPCR lessons learnt exercise suggested that the process was successful but that there were some improvements that could be made for

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[47] Gas distribution price control review - Review of process open letter
http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/GDPCR%20lessons%20learnt_open%20letter.pdf
[48] Associated documents
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=469&refer=Networks/GasDistr/GDPCR7-13

future price control reviews. We are using this feedback to improve the process for DPCR5. The main suggestions for improvement are outlined below.

Stakeholder engagement

6.36. Some respondents felt that they were not consulted with sufficiently and that they wanted more detailed information on the companies' plans. For DPCR5 we have made use of workshops where various stakeholders can take part and ask questions and will hold a further round in 2009. We have also stressed that we expect each DNO to undertake consultation with its regional stakeholders in order to inform its business plans.

6.37. In DPCR5 we have endeavoured to use workshops effectively. We consulted with stakeholders about agenda items in advance of the May workshops and allowed them the scope to send specific attendees for specific topics. We received positive feedback on these workshops in terms of their usefulness to stakeholders but remain open minded on how these could be improved for the second year of DPCR5. We plan to publish parts of the FBPQs shortly after receiving them from the DNOs in February 2009. We will then publish further details through our May 2009 initial results paper. This should allow other stakeholders the opportunity to review the DNOs' plans at an earlier stage.

Data submission and analysis

6.38. A further area for improvement for GDPCR was the large number of supplementary questions that the gas distribution networks (GDNs) received after completing the detailed BPQs. The RRP process which will be used for DPCR5 has been in place since DPCR4 whereas this was a new development for GDPCR.

6.39. The established RRP process for DPCR5 has maintained a flow of information and allowed robust submissions of accurate data. Ofgem is also working with DNOs to develop FBPQs and associated guidance. We plan to submit detailed FBPQs to the DNOs to explain their forecasts for the DPCR5 period.

6.40. We recognise legitimate concerns from some DNOs that they would like to limit the number of times that Ofgem requests additional information to a reasonable level. We are trying to address this issue by building on our work with RRP data to develop a considered FBPQ.

Consultation documents and consultation periods

6.41. GDNs, suppliers, and other respondents suggested that some consultation periods were too short, which was also highlighted in the transmission price control review (TPCR). There were suggestions that a minimum period of six to eight weeks should be used. This is one of the reasons why we have not built a formal September updated proposals document into DPCR5. We also plan to have longer consultation of between ten and 12 weeks, for each of the four main documents.

Dealing with issues early

6.42. Respondents suggested that some issues, such as specific policy areas and licence drafting, could be dealt with earlier in the process. For DPCR5 this policy paper sets out initial views on policy areas, including draft impact assessments. We intend to begin licence drafting early after initial proposals in line with the approach for GDPCR.

Committee of the Authority

6.43. The GDNs believed that they had sufficient access to the Committee of the Authority but would have preferred longer meeting times and a more two-way debate. The DPCR5 team has established a Committee of the Authority with meetings held with the DNOs in September/October 2008 and with further meetings planned prior to publication of initial proposals and again before final proposals. We will seek feedback from both the DNOs and the Committee on how these can be improved throughout the DPCR5 process.

Impact assessments

6.44. The majority of respondents agreed with our proposed approach to publish specific impact assessments for each important decision. We have followed this approach in this document by providing draft impact assessments relating to proposals dealing with use of system charges for generators who connected prior to 2005 (G2010), innovation and worst served customers. We will include full impact assessments on these options and other arising issues in initial proposals, where appropriate.

DNO stakeholder engagement

6.45. In our initial consultation document we outlined our expectations that each DNO should consult with its regional stakeholders in order to involve them in the DPCR5 process and to consider and take account of their views. Each DNO has now undertaken this work, and has used a range of approaches to do so. A summary outlining each DNO’s approach and our initial views on their efforts is outlined in appendix 12.

6.46. Overall we recognise that this is a difficult and technically complex area and so getting 'normal' customer insight is problematic. Appendix 12 summarises each DNO's views on the approaches that they used to gather stakeholders' views. There seems to be a benefit in DNOs consulting with stakeholders using costed options as this allows stakeholders to better consider these issues in context.

6.47. We do not think that the stakeholder engagement by the DNOs is a substitute for the work that Ofgem is undertaking through tactics such as, the Consumer Challenge Group, Ofgem-led workshops and consumer research. However, the DNOs have found this exercise to be generally helpful and most have suggested that they will seek to learn from this work and will continue to engage with stakeholders in the future. They have also reported that the stakeholders themselves were positive about being involved in informing the plans for their local region.

6.48. Following the completion of this round of stakeholder engagement we expect the DNOs to demonstrate how they have used this work to inform their decisions on the areas that they will focus on during DPCR5.

Appendices

Index

Index - Supplementary appendices

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 13 February 2009 and should be sent to:

DPCR5 Response
Electricity Distribution

Ofgem
2nd floor
9 Millbank
London
SW1P 3GE

020 7901 7026

DPCR5.reply@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Any questions on this document should, in the first instance, be directed to:

Nicola Cocks
Programme Management, Electricity Distribution

9 Millbank, Ofgem, London, SE1P 3GE
020 7901 7036

nicola.cocks@ofgem.gov.uk

Chapter 1: Introduction and overview

Question 1: Do you agree with our assessment of how the DPCR4 settlement has performed in practice?
Question 2: Do you agree with the main lessons we have drawn from this assessment?
Question 3: Have we identified appropriate measures to address our concerns and deliver a settlement that provides better rewards/penalties for highly performing/poorly performing companies?
Question 4: Do you think our proposal to base DNOs' incentives for under/outperformance around their effective return on equity is appropriate?
Question 5: If you do, what range of return on equity do you think would represent a fair balance between customers' and shareholders' interests to reward increased efficiency, better service and innovation, whilst maintaining strong incentives for shareholders of any poorly performing DNOs to improve performance?

Chapter 2: Environment

Question 1: Do you agree with our view of future uncertainties and the need for DNOs to change their way of working and thinking to encompass innovation and flexibility?
Question 2: What are your views on our proposals for DNOs to provide more information to help low carbon initiatives and have we adequately identified and defined the information requirements?
Question 3: Do you agree with our proposal that all distributed generation should pay use of system charges, and if not, can you provide evidence to substantiate your specific concerns?
Question 4: Do you agree that the distributed generation (DG) incentive should be retained? Should embedded transmission be deemed relevant DG?
Question 5: What are your views on our proposals on innovation and flexibility? How would you rate their feasibility and which option is most likely to drive the more innovative and flexible behaviour that we are seeking?
Question 6: What are your views on our proposal to set an incentive on transmission grid exit charges?
Question 7: What are your views on our losses proposals, and do you have any additional comments on the option to install smart meters on low voltage substations?
Question 8: What are your views on the various aspects of the business carbon footprint proposals?
Question 9: What are your views on our proposals for refining the undergrounding scheme? In particular, should we apply caps per km of cable by voltage level or should we remove all voltage caps and just have a single overall cap?
Question 10: Do you agree with our proposed approach for the treatment of fluid filled cables?

Chapter 3: Customers

Question 1: Do you think that the range of existing and proposed arrangements will deliver the levels of service customers expect?
Question 2: What percentage of revenue/return on equity should be exposed to customer service and how should it be split between the various areas?

Question 3: Do you agree with our intention to develop a broad measure of customer satisfaction and the proposed advocacy approach?
Question 4: Do you agree with our proposed approach to connections, which of the options do you support and why?
Question 5: Do you agree with the proposed amendments to the IIS (in full) and what are your views on how incentive rates should be structured?
Question 6: Do you agree with our proposed long-term objective of DNOs being able to automatically know which of their customers are off supply and the exact times, and if so what is the appropriate timescale to achieve this?
Question 7: Do you agree with the proposed focus on worst served customers and which of the options do you prefer?
Question 8: We have raised some detailed questions throughout this chapter and the appendix. We welcome views on these issues.

Chapter 4: Networks

Question 1: Have we identified the right behaviours for DNOs? Are there others which should be included?
Question 2: What action should we take where a DNO has deferred investment and created a backlog in DPCR4?
Question 3: What approach should we manage to deal with volume uncertainty?
Question 4: What approach should we take to price uncertainty?
Question 5: Should we be looking to equalise incentives for opex and capex? If so, what approach should we adopt?
Question 6: Do you consider that we should make refinements to the IQI? If so, what changes should we make?
Question 7: What action should we take where DNOs provide insufficient output information as part of their February FBPQ?
Question 8: Do you agree with our proposed approach to assessing network operating costs and indirect costs?
Question 9: Do you agree with our proposed approach for assessing network investment?

Chapter 5: Financial issues

Question 1: Have your views on the appropriate methodology for setting the cost of capital or on indexing the cost of debt changed as a result of the current turmoil in the capital markets?
Question 2: What is the appropriate timing of actuarial valuations for setting ex ante pension allowances (see also appendix 10)?

Chapter 6: Process

Question 1: We invite views on which format stakeholders would find most useful for the Ofgem workshops to be held in January 2009.
Question 2: We invite views on our proposed process.

Appendix 2 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ('the Authority'), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[49]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[50].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[51]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[52]

[49] entitled 'Gas Supply' and 'Electricity Supply' respectively.
[50] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[51] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[52] The Authority may have regard to other descriptions of consumers.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed[53] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[54] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

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

Appendix 3 - Glossary

123

132 kV

132 kV refers only to 132 kV assets

A

Areas of Outstanding Natural Beauty (AONB)

An AONB is an area of countryside with significant landscape value that has been designated by the Countryside Agency. The purpose of the designation is to conserve and enhance the natural beauty of the landscape; ANOBs rely on planning controls and practical countryside management.

Active Network Management (ANM)

Systems that operate to take action automatically to maintain networks within their normal operating parameters.

B

Business Carbon Footprint (BCF)

Total set of GHG emissions caused directly and indirectly by the operation of a business.

Department of Business Enterprise and Regulatory Reform (BERR)

C

CUSC Amendment Proposal (CAP)

See CUSC below.

Capital Expenditure (Capex)

Expenditure on investment in long-lived distribution assets, such as underground cables, overhead electricity lines and substations.

Central Business District (CBD)

A key city centre area with high density business or commercial properties which yield a high economic value added relative to other parts of the country.

Combined Heat and Power (CHP)

The simultaneous generation of usable heat and power (usually electricity) in a single process, thereby discarding less wasted heat.

Customer interruptions (CIs)

The number of customers whose supplies have been interrupted per 100 customers per year over all incidents, where an interruption of supply lasts for three minutes or longer, excluding re-interruptions to the supply of customers previously interrupted during the same incident. It is calculated as:

$$\frac{\text{The sum of the number of customers interrupted for all incidents} * 100}{\text{The total number of customers}}$$

Competition in Connections (CinC)

Connections Industry Review (CIR)

Ofgem publishes an annual CIR which aims to highlight trends in the market for gas and electricity connections (including connections for distributed electricity generation) and to monitor the development of competition.

Customer minutes lost (CMLs)

The duration of interruptions to supply per year – average customer minutes lost per customer per year, where an interruption of supply to customer(s) lasts for three minutes or longer, calculated as:

$$\frac{\text{The sum of the customer minutes lost for all restoration stages for all incidents}}{\text{The total number of customers}}$$

Corrected ordinary least squares (COLS)

Corrected ordinary least squares is a form of benchmarking in which the frontier is estimated (rather than calculated) using statistical techniques. A functional form for the production / cost function is specified and this is estimated using ordinary least squares techniques. The calculated line of best fit is then shifted to the efficient frontier or relevant benchmark by adding the absolute value of the largest negative estimated error to that of the other errors (for a cost function).

Carbon Reduction Commitment (CRC)

Defra's emission trading scheme that targets large non-energy intensive commercial users and government organisations, with the aim of incentivising improvements in energy efficiency, with effect from 2010.

Connection and Use of System Code (CUSC)

Contractual framework for connection to, and use of, National Grid's high voltage transmission system.

D

Defined benefit (DB)

Pension scheme in which an employee's pension is based on number of years of service and final salary (or in newer schemes average salaries over the employment period) with sponsoring employer(s).

Distribution Connection Use of System Agreement (DCUSA)

The DCUSA provides a single centralised document which relates to the connection to and use of the distribution networks.

Data envelope analysis (DEA)

An approach which determines an efficiency frontier or "envelope" using linear programming techniques.

Department of Energy and Climate Change (DECC)

Department for Environment, Food and Rural Affairs (DEFRA)

Distributed Generation Incentive (DG / DGI)

The DG incentive is a 'hybrid' incentive scheme that provides for partial pass-through treatment of reinforcement costs incurred in providing network access to DG and a £/kW revenue driver to incentivise connection of DG. The 'hybrid' incentive sought to combine incentives for efficiency (via the incentive rate) with protection against cost uncertainty (via the cost pass through). An additional element to the incentive was created to provide ongoing network access (availability). The allowances were set based on the DNOs' expectations of likely DG connections and the costs associated with those connections.

Distribution Network Operators (DNOs)

A DNO is a company which operates the electricity distribution network which includes all parts of the network from 132kV down to 230V in England and Wales. In Scotland 132kV is considered to be a part of transmission rather than distribution so their operation is not included in the DNOs' activities.

There are 14 DNOs in the UK which are owned by seven different groups.

Distribution Price Control Review 4 (DPCR4)

Distribution price control review 4. This price control runs from 1 April 2005 until 31 March 2010.

Distribution Price Control Review 5 (DPCR5)

Distribution price control review 5. This price control is expected to run from 1 April 2010 until 31 March 2015.

Distribution Services Area (DSA)

A geographic area in which DNOs are obliged by their licence to provide specific electricity distribution services.

Demand side management (DSM)

Demand Side Management (aka Load Management) is any mechanism that allows a customer's demand to be intelligently controlled in response to events on the power system. Such events would include lack of network capacity or insufficient generation.

E

Environment Agency (EA)

Embedded Debt

A utility's actual historic debt portfolio.

Extra High Voltage (EHV)

Includes all voltage levels above 20kV up to but excluding 132kV.

Energy networks association (ENA)

Early Retirement Deficiency Contributions (ERDCs)

Cost of providing enhanced pension benefits granted under severance arrangements which have not been fully matched by increased contributions.

Electricity, Safety, Quality and Continuity Regulations 2002 (ESQCR)

The ESQCR specify safety standards, which are aimed at protecting the general public and consumers from danger. In addition, the regulations specify power quality and supply continuity requirements to ensure an efficient and economic electricity supply service to consumers.

Environmental Transformational Fund (ETF)

Initiative for supporting the commercialisation of low carbon energy and energy efficiency technologies, jointly funded and administered by Defra and BERR.

Environmental Working Group (EWG)

Industry working group organised by Ofgem to discuss environmental policy issues for DPCR5.

F

Forecast business plans (FBPs)

Forecast business plan questionnaire (FBPQ)

Expenditure information requested by Ofgem from the licensees relating to the period from 2008-09 to 2014-15.

Fluid Filled Cables (FFC)

High voltage underground cables that use oil as an insulator.

Funds from Operations (FFO)

This is one of a number of ratios used currently by credit rating agencies to assess financeability.

G

Gas distribution networks (GDNs)

GDNs transport gas from the National Transmission System to final consumers and to connected system exit points. There are currently eight GDNs in Great Britain which comprise twelve local distribution zones.

Gas Distribution Price Control Review (GDPCR)

The review of the price control applying to gas distribution networks. The review extended the existing price control for the year 2007-08 and reset the control for the period commencing 1 April 2008.

Generator Distribution Use of System Charges (GDUoS)

See UoS below.

Greenhouse Gas Emissions (GHG)

Guaranteed Standards of Performance (GSOPs)

Guaranteed Standards set service levels to be met in each individual case and are established by a Statutory Instrument. If the licence holder fails to provide the level of service required, it must make a payment to the customer affected subject to certain exemptions.

Grid Supply Point (GSP)

Point of connection between the GB transmission system and a distribution network, large power station or other non-embedded customers where National Grid delivers electricity.

H

Hydro fluorocarbons (HFC)

Health Indices (HI)

High impact low probability (HILP)

Electricity distribution networks are designed and built to ensure supply continuity for most customers during planned outages and faults that are considered to be credible events. There is a small risk that a more extreme event occurs that has a very high impact on the ability of the distribution system to provide supply continuity. Such an event could result in extended periods of supply interruption for a significant number of customers and is referred to as HILP.

Her Majesty's Revenue and Customs (HMRC)

High Voltage (HV)

Includes all voltage levels above 1kV up to and including 20kV.

I

Inspections and maintenance (I&M)

The activities of both:

- Inspections - the visual checking of the external condition of assets, and
- Maintenance - the invasive ('hands on') examination of plant and equipment.

Impact Assessment (IA)

Ofgem has a statutory duty to carry out IAs in certain circumstances concerning decisions that it considers to be "important". This is set out in section 5A of the Utilities Act 2000. If we decide that it is not necessary to publish an IA then we must publish a statement explaining the reasons for our decision.

Independent Connection Provider (ICP)

Independent distribution network operators (IDNOs)

See DNO above.

Innovation Funding Incentive (IFI)

The IFI is intended to encourage DNOs to invest in appropriate research and development activities that are designed to enhance the technical development of distribution networks (up to and including 132 kV) and to deliver value (i.e. financial, supply quality, environmental, safety) to end consumers.

Interruptions Incentive Scheme (IIS)

On 1 April 2005 Ofgem introduced a revised interruptions incentive scheme which provides financial incentives to DNOs with respect to the average quality of service they provide in terms of:

- the number of interruptions to supply, and
- the duration of interruptions to supply.

DNOs may be rewarded or penalised by up to 3 per cent of revenue, depending on performance relative to their interruptions targets in each year of the scheme.

Information Quality Incentive (IQI)

The IQI mechanism incentivises DNOs not to inflate their forecasts. It does this in two ways – by giving additional income to companies who forecast spend close to our assessment and by providing these companies with a higher incentive rate than those companies with higher capex forecasts, thereby increasing their rewards for outperformance.

L

Long-term Energy Network Scenarios (LENS)

The ENA commissioned a study to develop publicly defensible scenarios covering the long term investment needs of the electricity transmission and distribution industries to support a positive ENA communications strategy on the long term future of energy networks.

Load related expenditure (LRE)

The installation of new assets to accommodate changes in the level or pattern of electricity or gas supply and demand.

Long Term Development Statements (LTDS)

LTDS' provide information about a DNO's network that allows qualified parties to make initial assessments of connection opportunities. In 2002, Ofgem introduced a licence change that required all DNOs to produce them annually.

Low Voltage (LV)

All voltage levels up to and including 1kV.

M

Market Asset Ratios (MAR)

The MAR represents the ratio between the market value of a regulated business and its regulatory asset value.

Modern Equivalent Asset Value (MEAV)

The total rebuild cost of the network using modern equivalent assets.

Megawatt-hour (MWh)

A measure of energy production or consumption equal to one million watts produced or consumed for one hour.

N

National Association for Areas of Outstanding Natural Beauty (NAAONB)

The National Association for Areas of Outstanding Natural Beauty was formed in 1998 as an independent organisation to act on behalf of Areas of Outstanding Natural Beauty in England and Wales.

National Grid Electricity Transmission (NGET)

NGET owns and maintains the high-voltage electricity transmission system in England and Wales.

Net present value (NPV)

Net present value is the discounted sum of future cash flows, whether positive or negative, minus any initial investment.

Net present value (NPV) neutral

Alternative revenue profiles are net present value neutral if they have the same NPV. We usually use this term in the context of spreading revenues over time (i.e. a price control period) where the costs that they represent have already been incurred, or in comparing different profiles of allowed revenue.

O

Operations and Maintenance (O&M)

Ordinary Least Squares (OLS)

A standard regression technique for estimating the line of best fit between cost and scale variables. See COLS above.

Office of Rail Regulation (ORR)

The Office of Rail Regulation is the independent safety and economic regulator for Britain's railways.

P

Planning Policy Statement 22 (PPS 22)

This sets out the Government's policies for renewable energy, which planning authorities should have regarded when preparing local development documents and when taking planning decisions.

Pension Protection Fund (PPF)

The Pension Protection Fund established to pay compensation to members of eligible defined benefit pension schemes, when there is a qualifying insolvency event in relation to the employer and where there are insufficient assets in the pension scheme to cover Pension Protection Fund levels of compensation.

R

Research and Development (R&D)

Regulatory asset value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee's regulated distribution or (as the case may be) transmission business (the 'regulated asset base'). The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base at privatisation and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock. The revenues licensees are allowed to earn under their price controls include allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

Regional Development Agencies (RDA)

Renewable Energy Association (REA)

Renewable Energy Sources (RES)

Return on Regulatory Equity (RORE)

The rate of return to the portion of the RAV assumed to be financed by equity under DPCR4 final proposals. The detailed calculation of the rate is described in Appendix 11.

Real price effects (RPE)

Increase in prices over and above increases in the Retail Price Index (RPI). For example, increases in the cost of copper, steel, direct or contract labour over and above increases in RPI.

RPI-X

The form of price control currently applied to network monopolies. Each company is given a revenue allowance in the first year of each control period. The price control then specifies that in each subsequent year the allowance will move by 'X' per cent in real terms.

Registered Power Zone (RPZ)

RPZ is a mechanism to encourage DNOs to develop and demonstrate new and more cost effective technologies for connecting and operating generation on their distribution systems. Where a DG connection meets the requirements and is registered as a RPZ the DNO receives an additional incentive over and above the main DG incentive.

Regulatory reporting pack (RRP)

The price control review information submitted annually to Ofgem under standard licence condition 52 in accordance with (and in the form and content prescribed by) the price control review reporting rules.

S

Sulphur Hexaflouride (SF6)

One of the most potent greenhouse gases and is widely used in transmission and distribution equipment.

Stochastic Frontier Analysis (SFA)

An econometric approach to estimating the efficiency frontier where deviation from the frontier is attributable to both inefficiency and random errors or disturbances.

Shadow Price of Carbon (SPC)

Economic measure of the damage costs of climate change caused by each additional tonne of greenhouse gas emitted, based on a stabilisation trajectory and in line with the marginal abatement costs of reaching the stabilisation goal (taking uncertainty into account).

T

Total Factor Productivity (TFP)

A measure of the level of outputs produced from a given quantity of input factors. TFP is an index method of comparing the efficiency of firms using input and output data over time to determine changes in relative productivity.

Traffic Management Act (TMA)

The Traffic Management Act was introduced in 2004 to tackle congestion and disruption on the road network. The Act places a duty on local traffic authorities to ensure appropriate movement of traffic on their road networks. It gives authorities additional tools to manage the coordination of street works[55].

Transmission Price Control Review (TPCR)

The TPCR will establish the price controls for the transmission licensees which will take effect in April 2007 for a 5-year period. The review applies to the three electricity transmission licensees, National Grid Electricity Transmission, Scottish Power Transmission Limited, Scottish Hydro-Electric Transmission Limited and to the licensed gas transporter responsible for the gas transmission system, NGG.

U

Use of System charges (UoS)

Charges paid by generators and demand customers, usually via suppliers, for the use of the distribution network.

W

Weighted Average Cost of Capital (WACC)

This is the weighted average of the expected cost of equity and the expected cost of debt.

[55] Department for Transport: http://www.dft.gov.uk/pgr/roads/tpm/tmaportal

Appendix 4 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

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

1.2. Please send your comments to:

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