Electricity Distribution Price Control Review Methodology and Initial Results 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 present and future consumers. We set a price control every five years. This sets the total revenue allowances that each DNO can collect from customers 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 third document in the review. We have set out details of our cost assessment methodology and our initial results. We have also presented our proposals for two areas of quality of service and our proposed approach to dealing with tax, regulatory asset value and overall incentives. This is the final consultation before we publish our initial proposals on each company's revenue requirements in late July 2009.

Contact name and details: Rachel Fletcher, Director Distribution

Tel: 020 7901 7209

Email: DPCR5.reply@ofgem.gov.uk

Team: Electricity Distribution

Context

In December 2008, we published our Policy Paper for the distribution price control review (DPCR5). The document focussed on three key themes, the environment, customers and networks and set out 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.

In February 2009 all DNOs submitted updated forecasts for the final two years of DPCR4 and the five years of DPCR5. We held initial discussions with each of them. Forecasts have reduced from their initial level in August 2008, but still show a significant increase in both network investment and operating costs between DPCR4 and DPCR5 as outlined in this document. We have identified significant issues with the forecasts and will seek further information from the DNOs to justify their forecasts.

This document sets out details of our cost assessment methodology and the initial results for a number of core cost areas. We will continue to develop our work in this area as we develop draft allowances for the Initial Proposals document. We have not yet completed out analysis or considered our draft allowances. Readers should not therefore try to draw any inferences about them from any of the figures published in this document.

Since December there has been continued volatility in the economy, which makes it even more difficult than usual to forecast accurately. The need for investment is highly uncertain and two key drivers will be how effective measures to improve energy efficiency are and how long it takes for the economic recovery to begin. Input prices, including those that affect financing costs and operating expenditure, will be highly influenced by global economic conditions, the length of the recession and any periods of general deflation. We will need to carefully consider how best to manage this risk and uncertainty so that DNOs do not make windfall gains at customers' expense from economic circumstances, but have sufficient resources over the five years to meet their needs over a wide range of possible outcomes. We have set out a chapter on our evolving thinking on how best to deal with this uncertainty.

We have continued to hold a number of industry working groups focussed on the three key DPCR5 themes and financial issues, which have informed the development of our policy proposals. We continue to make use of these groups to develop our thinking on financial issues, outputs and other policy matters not included in this document, such as improving connections service, basing DNO rewards on a broader measure of customer satisfaction and encouraging DNOs to reduce losses and innovate to tackle climate change. We will set out our proposals for these areas in Initial Proposals in July.

Associated Documents

- Update letter of the DPCR5 process (151/08)
- Electricity distribution price control review. Initial consultation document (32/08)
- Electricity distribution price control review. Policy Paper (159/08)
- Regulating energy networks for the future: RPI-X@20 Principles, Process and Issues (13/09)

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Summary

Our objective in this review is to put in place a price control that encourages DNOs to: play a much larger role in helping to tackle climate change, improve all aspects of customer service, and continue innovating to find ways of reducing the costs of providing secure and reliable electricity networks. The price control needs to encourage the DNOs to prepare for the significant changes to their businesses and the services that could occur over the next few years, as we move to a low carbon economy. These could include the need for active, two-way networks because of the greater use of local, distributed generation and electric vehicles, and the opportunities for smarter networks associated with the mass rollout of smart meters.

This price control review will have been a success if the settlement provides reasonable rewards for delivering these objectives and if those DNOs that innovate and significantly outperform a broad range of output measures earn higher returns.

For the first time, we want to base the settlement around each DNO committing to deliver a defined set of outputs in a sustainable manner in return for the revenues they collect from customers. It also entails targeting incentives to improve the link between performance and rewards so that any company that fails to deliver earns lower returns and companies that outperform or successfully innovate in a way that provides real benefits to customers earns higher returns. We aim to make a holistic assessment of the control to understand the scope that DNOs will have to under and outperform our assumed shareholder returns, in order to avoid too narrow a focus on the headline cost of capital in the final stages of the review.

We seek comments on our methodologies for assessing DNO cost forecasts, the emerging results. We also welcome comments on what other factors we should take into account as we develop our view of the revenues the DNOs should recover from customers over the 2010 to 2015 period. This should reduce the need for debate of our methodologies post publication of our Initial Proposals in July.

The DNOs have collectively bid for a very substantial increase in allowed revenues over the DPCR5 period. They have requested that customers fund an increase in network investment of over 60 per cent on average (and by nearly 90 per cent on some networks) and in operating costs of 11 per cent on average (up to 20 per cent on some networks). The DNOs are also saying that current capital market conditions will require us to set a higher cost of capital than at DPCR4. What the DNOs have asked for - before considering the DNOs' arguments on the cost of capital or other factors which might drive up costs - would lead to increases of an average of around 12 per cent of the distribution element of customers' electricity bills, with the highest DNO seeking over 25 per cent, which equates to a 5 per cent increase in a typical domestic electricity bill. Business customers will face larger increases.

At every price control review, we aim to challenge robustly but fairly the companies' requests. But the scale of the proposed increases and the current economic climate, with many businesses and households feeling the strain, make it more important than ever to do this. However, we also need to recognise some of the drivers of these cost increases, such as the need to replace many distribution assets that are now 40 to 50 years old and are reaching the end of their lives. We must make sure we allow the companies to continue to invest to maintain the high levels of network reliability that customers enjoy and expect.

The first step we take in this process is to assess each DNO's cost forecasts using methodologies we have developed for network investment and network operating costs. The results of these methodologies are key to informing our view of the efficient level of costs. However, our view will ultimately also be informed by a number of other factors. These include the outputs the DNO is committing to delivering, further information from the DNOs and feedback from stakeholders on what they would like each DNO to achieve.

Through our methodologies we have identified issues with the forecasts submitted by all DNOs, either in terms of the forecast volume of network investment, the unit cost of additional capacity or the forecasts of network operating and indirect costs. DNOs will be invited to provide further justification of their forecasts in the coming months. We will expect the DNOs to provide compelling evidence before we adjust our position. We also recognise that in some areas we need to develop and refine our methodologies to reflect responses to this consultation and further information provided by the DNOs before formulating our view of efficient costs for Initial Proposals.

The second aim of this document is to share our views on the quality of service incentives that are close to completion so that we can present near Final Proposals in July. We have developed the detail of a scheme aimed at encouraging DNOs to address the quality of service delivered to worst served customers. We also propose revisions to the targets in the unplanned interruptions incentive scheme so that they more closely reflect customers' willingness to pay for, and the cost of, improved performance. We are still assessing and analysing the information we received from the distribution companies in response to our consultation on how we should deal with pension costs as part of the current price control review.

Finally, in this document, we set out more detail on a range of price control "mechanics" with a view to getting an early response to our emerging thinking. This includes important matters such as managing uncertainty (where we have proposed mechanisms for managing uncertainty around the volume of demand and the price of inputs) and more detail on output definitions (where real progress is being made towards a consistent approach to defining network investment outputs across all DNOs). We set out in some detail how our objective of equalising capital expenditure and operating expenditure incentives might work in practice. This important development encourages the DNOs to consider solutions such as contracting with distributed generation and demand side management to solve network constraints. As part of this document we also set out our views on how the information quality incentive (IQI) might operate. This is the tool that we use to encourage the DNOs to submit more accurate cost forecasts for the DPCR5 period. We set out an IQI matrix which DNOs should refer to when submitting their updated forecasts in June.

We have developed the proposals and approach in this document through discussions with the DNOs and other stakeholders, including those who attended our workshops in January. We particularly welcome the input we have received from the Consumer Challenge Group that we have set up to give us a consumer perspective on what can be technically complex areas. Their comments have informed all of our proposals but most specifically our quality of service proposals, our emerging thinking on managing uncertainty and our commitment to equalising incentives.

1. Introduction and overview

Chapter Summary

This chapter sets out the background to the price control review. It summarises the cost assessment methodology and the policy issues included in this document. We have also set out our planned process and way forward.

There are no questions in this chapter

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 domestic electricity 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 third consultation of DPCR5. We published the initial consultation document[1] 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 the process we intend to follow. We published the Policy Paper in December 2008 and 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. In these documents we have 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

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

- **Networks:** encouraging DNOs to invest efficiently, so that they provide secure and reliable supply at an efficient 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. One of the purposes of this document is to gather views on the DNOs' forecasts, our cost assessment methodologies, the emerging results and how these should be used together with a wider range of information and knowledge to inform our view of the costs DNOs should recover from customers over the DPCR5 period. Our view of efficient costs (also referred to as "cost baselines") will be included in our Initial Proposals for the price control settlement which we will publish in late July.

1.5. This document sets out a snapshot of the data and our cost analysis at a particular point in time. We will continue to develop our work in this area as we develop draft allowances for the Initial Proposals document. We have not yet completed out analysis or considered our draft allowances. Readers should not therefore try to draw any inferences about them from any of the figures published in this document. We have been having a range of discussions with the DNOs and other stakeholders through groups, bilateral cost meetings and other forums. Where possible we have sought to take these discussions into account in developing our approach but there are inevitably areas where further work needs to be carried out. In addition there is further information being received from the DNOs via supplementary question responses and discussions with the companies. We will receive updated DNO forecasts in late June. At this stage we have primarily focused our analysis on core areas of costs covering the majority of spend. There is further work to be carried out in areas of expenditure such as operational IT (telecoms connected to the network) and investment to mitigate High Impact Low Probability Events (HILP). This will be taken into consideration in the development of our Initial Proposals baselines.

1.6. This document has two parts:

- **Part 1** provides an overview of the DNO forecasts for DPCR5 and consults on our cost assessment methodologies and emerging results and how these should be used together with a wider range of information to inform our cost baselines for Initial Proposals. We consider the core areas of network investment, network operating costs and indirect costs. We also set out our approach for analysing costs associated with distributed generation, losses and discretionary investment.

- **Part 2** contains our latest thinking on policy and price control mechanics. This includes the quality of service incentive, the Information Quality Incentive (IQI), measures to manage uncertainty and taxation.

1.7. In addition, we have an appendix document that sets out much more detail on our cost assessment methodologies and results. It also sets our further information on the policy areas.

1.8. We are still assessing and analysing the information we received from the distribution companies in response to our consultation on how we should deal with pension costs as part of the current price control review.

DNO forecasts

1.9. In February 2009 all DNOs submitted updated forecasts for the final two years of DPCR4 and the five years of DPCR5. The DNOs have collectively bid for a very substantial increase in allowed revenues over the DPCR5 period. They have requested that customers fund an increase of 65 per cent in network investment between DPCR4 and DPCR5, but this varies significantly across DNOs from 41 per cent to 89 per cent. The main drivers of the increase in costs are:

- asset replacement ,which is forecast to step up again in DPCR5 as assets that were installed during the peak of investment in the 1950s and 1960s come up for renewal. This represents 30 per cent of the increase,
- general reinforcement to increase network capacity in response to change in demand or generation which contributes 15 per cent,
- real growth in input prices. This represents 16 per cent of the increase, and
- increases in legal and safety investment requirements which contribute 10 per cent.

1.10. While there has been a significant reduction in the forecasts since August 2008, when the DNOs provide us with indicative figures for the DPCR5 period, we are still surprised by the size of forecasts for network reinforcement and input prices given current macroeconomic conditions and in the contraction in economic output and general deflationary pressure throughout the economy.

1.11. Overall DNOs are forecasting a 14 per cent increase in network operating costs, indirect costs and non-operational capex between DPCR4 and DPCR5 but this varies between 5 and 24 per cent. The main drivers of the increase in costs are:

- real growth in input prices. This represents 60 per cent of the increase,
- growth in engineering indirect work (such as project management) closely associated with direct activities, which contributes 17 per cent of the increase, and
- forecast increases in network operating costs (for example inspections and maintenance) which contribute 13 per cent of the increase.

Methodology

Background

1.12. At the last price control review (DPCR4) we recognised that our work was made more difficult because we did not have robust and consistent data upon which to base our analysis. We also recognised that the requirement for a single historical data request during a price control placed too heavy a burden on the DNOs to produce data that their systems were not developed to provide. We now capture cost information annually via a regulatory reporting pack (RRP) which includes both detailed cost spreadsheets and narrative explaining cost movements. Each year we review the data and hold meetings with each of the DNOs to discuss the issues that arise. For example, we are now benchmarking network operating costs and indirect costs using three years' data rather than simply relying on information from a single year.

1.13. The process of cost reporting has also allowed us to develop a stronger in-house team, which has greater experience of the DNOs and their activities and an understanding of each company's strengths and weaknesses. This means that we are better placed than ever to sense check our methodologies and apply our wider experience and knowledge to the outcomes.

Methodologies

1.14. The DNOs have presented us with their forecasts for the last two years of the current price control and for the five years covered by DPCR5. We present an overview of this data in chapter 2. DNOs' core costs broadly fall into six areas:

- Asset replacement is investment made to replace assets on the network that have reached a condition that is no longer fit for purpose and replacement is the most economic solution,
- Load-related investment is investment in new or replacement assets to increase network capacity in response to changes in demand and generation. The core costs include general reinforcement, investment associated with demand connections, investment associated with fault levels and diversions.
- Investment driven by legal and safety issues and operational IT and telecoms,
- Network operating costs such as the costs of repairing faults, inspections and maintenance and tree cutting;
- Indirect costs that are closely associated with direct activities such as project management, network design, and control centre costs etc; and
- Business support costs such as finance and regulation, HR, IS and property.

1.15. We have focused primarily on these core areas at this stage but there are also "non-core" costs where we are currently carrying out further analysis or where additional analysis will be carried out to inform Initial Proposals. For example, we are considering costs directly and indirectly contributing to climate change targets including preliminary investment in smart grids, metering at substations to quantify distribution losses and incremental investment to reduce losses. We are reviewing DNO proposals to mitigate the impact of High Impact Low Probability Events (HILP), which may not be captured by normal planning assumptions and investment to reduce the consequences of flooding. Our consultants are reviewing costs associated with connection of distributed generation (DG), All of this analysis will feed into our Initial Proposals.

1.16. Over the past few years and in parallel with the RRP process we have refined our approach to cost assessment. We have developed the asset replacement modelling taking into account experience from the last transmission review (TPCR4) and further thinking on how it should be used. This is a well understood methodology within the industry. It uses information on asset age profiles and asset lives to determine replacement volumes. We feed back information on what DNOs have actually achieved in DPCR4 and are forecasting to carry out in DPCR5 to refine our views on asset lives and volumes. This model provides a robust starting point for discussions on appropriate levels of asset replacement in DPCR5 and DNOs will have to provide us with robust condition-based evidence if they are to convince us it is necessary to carry out higher volumes of work than our model suggests. These discussions in turn allow us to refine our models further.

1.17. At DPCR4 our top down modelling for load reinforcement at all voltages focused on costs relative to net overall growth in units distributed and customer numbers. We have now tailored our EHV and 132kV modelling to focus specifically on areas of the network that need reinforcement. In essence this looks at the aggregate capacity that is being added at substations that need reinforcement relative to peak demand growth. It then benchmarks the costs of installing this capacity relative to the long-term marginal costs of adding additional capacity to the network. This approach highlights key issues with the DNOs' forecasts but is still being refined to ensure that the inputs to the modelling are on a consistent basis across all companies. Our analysis of network investment is discussed in chapter 4. We have explored developments in cost benchmarking and appointed a senior academic advisor to guide us on the most appropriate techniques and how these should be applied. We have moved from using a single year's data for the cost analysis to panel techniques using three years of RRP data. By the summer, it will be possible to extend this to four years. We are also carrying out data envelope analysis (DEA) and international benchmarking.

1.18. We have considered the appropriate cost drivers at a much more disaggregated activity level with the industry. This allows us to conduct our analysis at both a top-down and a more disaggregated level. We have had a wide range of discussions on potential adjustments for regional factors and business structure, how we should treat particular categories of costs including pensions, related party and severe weather. Our work on cost benchmarking is discussed in chapter 3.

1.19. As well as assessing efficient levels of cost for a base year, it is important to understand the trends in how costs will move over time. We are carrying out work to examine the scope for ongoing efficiencies through assessing relevant productivity trends (such as labour productivity) and trends in operating expenditure in other comparable industries. We have appointed consultants to carry out work for us on real input prices, both considering the robustness of work carried out by the industry and establishing their own forecast for a range of macroeconomic assumptions. They are also exploring the option of including an input price index to understand the potential advantage and disadvantages and practical implementation issues. This work is discussed in chapter 4.

Results

1.20. Our initial asset replacement modelling suggests some significant issues with the DNOs forecast volumes for asset replacement. The companies will have to provide a high standard of information based on robust condition based assessment or other drivers to convince us that higher volumes of new assets are required on their networks

1.21. In terms of our load-related modelling we have concerns with a number of DNOs. In these cases the model suggests that the levels of capacity being added are high relative to local demand growth or that forecast costs of the additional capacity are high relative to long-run average costs or a combination of both.

1.22. Our cost benchmarking results to date highlight some significant differences in efficiency across the DNOs. SSE and WPD appear to be low cost across a wide range of activities, while EDFE EPN, CN West and SPD appear to be high cost. Other DNOs fall into the middle of the range. We have found that the ranking of the DNOs is similar across a broad range of analysis and assumptions but that the magnitude of the differences is sensitive to a number of factors that require further discussion. These include potential adjustments for regional contractor and labour costs variations, costs for very urban or sparse areas and differences in in-sourcing and out-sourcing approaches.

Development of Initial Proposals

1.23. At DPCR4 we introduced the information quality incentive (IQI) to encourage DNOs to submit more realistic forecasts and to allow us to take those forecasts into account, along with the analysis carried out by Ofgem and PB Power, in the price control settlement. As discussed later in this chapter we are proposing to extend the IQI to cover network operating costs as well as network investment and any indirect costs closely associated with those areas of work. Based on the IQI mechanism, if companies submit a higher cost forecast this will be partially reflected in a higher cost allowance but the DNO will also receive a lower amount of additional income and less powerful incentives.

1.24. DNOs will have to provide a detailed explanation and audit trail of areas where the cost forecasts they provide us in June differ from those presented to us in February.

1.25. The cost assessment work that we are carrying out will be a key input into informing our baselines and highlighting issues with the DNO forecasts. But there is also a much broader range of evidence and other considerations that we will take into account in making our judgements, as illustrated in figure 1.1 below. For example:

- We expect DNOs to submit additional condition-based and other supporting evidence in response to the issues raised in this document to justify why their forecasts are appropriate. Given the IQI mechanism already takes some account of the DNO forecast, DNOs will need to present compelling evidence if we are to take their views into account.

- Output measures form a key part of the overall process and nature of the settlement at this review. We would expect the level of costs to be commensurate with the level of outputs each DNO is committing to achieve by the end of the DPCR5 period.

- We have already undertaken a wide range of consultation and meetings with the DNOs and other stakeholders, which have given us a better understanding of key issues with regards to the cost assessment process and a more thorough picture of the issues relating to particular DNOs' costs. We are considering the extent to which DNOs have undertaken effective customer engagement to inform their business plans and ensure that investment is appropriately targeted.

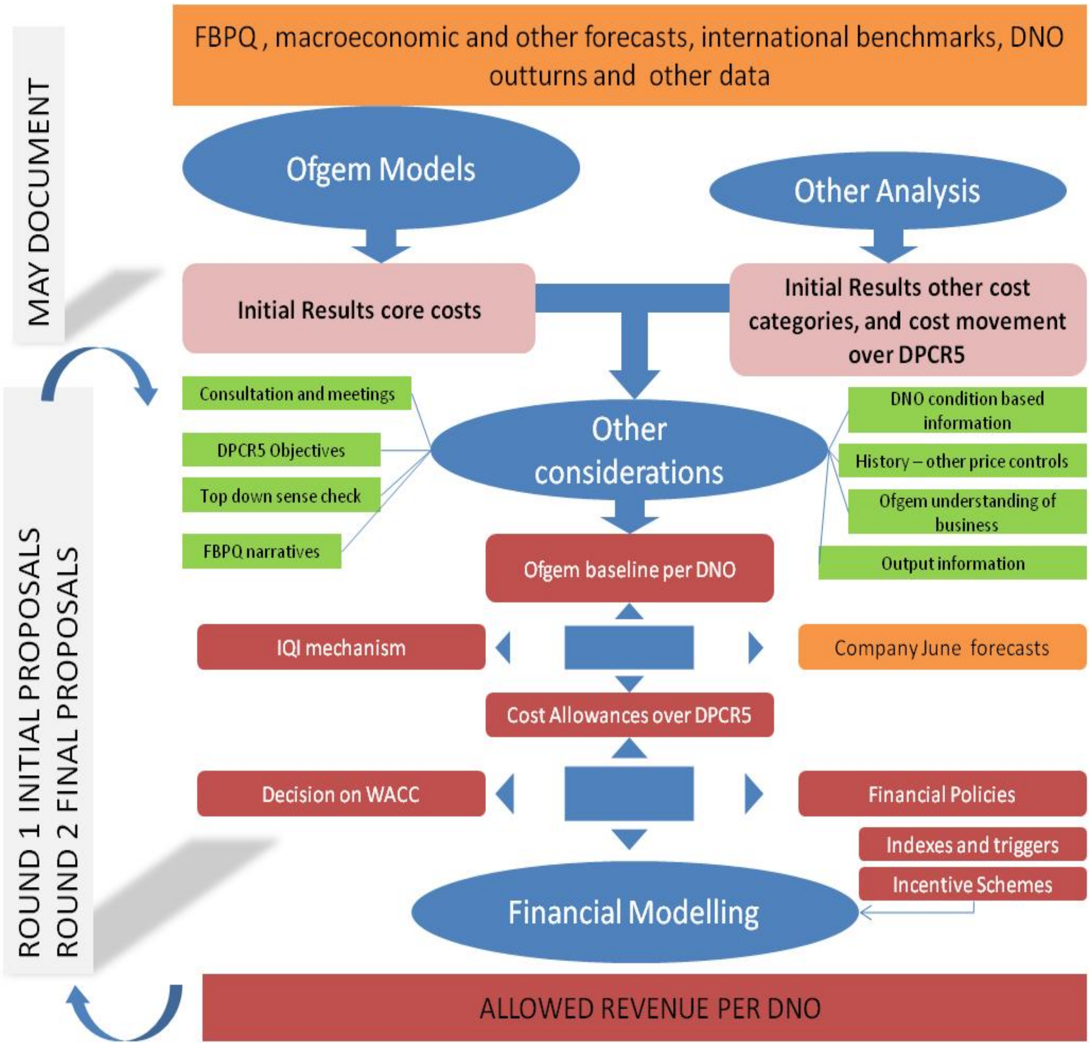
- We have reviewed the narrative submitted by each DNO to understand the robustness of their forecasting processes and associated assumptions. We have discussed issues arising from this as part of the bilateral cost meetings during March and April.

- We have a good understanding of DNOs' businesses and their historical performance through the RRP process and other price controls. We will consider companies' performance in DPCR4 and how they behaved as part of the previous price control process.

1.26. A key part of the process in reaching our views for Initial Proposals will be to draw this information together to develop our baselines for costs and to do an overall sense check to ensure that our proposals across the broad range of costs and associated incentives are appropriate for each of the DNOs. This will include reviewing our proposals against our three core objectives for the price control review in terms of terms of what should be delivered for customers, the environment and network condition.

1.27. It is worth noting that the cost allowances that arise from application of our baselines and the IQI mechanism is only one factor in our initial proposals. As illustrated below, we will formulate these proposals only after taking a holistic assessment of all elements of the settlement and making sure that they work together to provide an appropriate reward for delivering the price control objectives. We will bring the cost allowances together with incentive mechanisms (such as for losses and quality of service), decisions on financial matters (including the cost of capital and notional gearing) and the application of indexes and triggers to understand the impact the settlement might have on the financial performance of the DNOs. We will also be looking to model the extent to which there is scope for DNOs to out or underperform the regulatory settlement and to define more closely what might be the features of a well performing or poorly performing company.

Figure 1.1 - Overview of process for setting price control allowances



Outputs

1.28. We intend to base the settlement around each DNO committing to deliver a defined set of outputs in a sustainable manner in return for the revenues they collect from customers. These outputs should be high level metrics capturing network risk, rather than measures relating directly to volume of work (e.g. number of assets installed). We will be looking to the DNOs to stipulate the levels of output that they consider appropriate.

1.29. The outputs measures are primarily focussed on capturing what the DNO achieves through asset replacement expenditure (where outputs are related to the condition of network assets) and through expenditure on reinforcement (where outputs are related to the level of network utilisation). These categories of expenditure account for 78 per cent of forecast core network investment in DPCR5. We intend to introduce licence conditions on DNOs to develop output measures for other areas during the DPCR5 period.

1.30. We consider that real progress has been made by the industry in developing output measures and this should allow a common methodology to be put in place across the DNOs. Further detail on output measures is set out in chapter 8.

Policy issues

1.31. There are a number of specific policy areas where we are further advanced and are setting out initial proposals in this document. These include:

- certain key elements of quality of service incentives including our proposals for the unplanned element of the interruption targets, the incentive rates and our approach for worst served customers,
- the scope and form of the IQI mechanism, the methodology for rolling forwards the RAV in DPCR5 and our approach to equalising incentives across categories of costs,
- mechanisms for managing uncertainty, and
- our approach to calculating taxation allowances and further consideration of tax triggers.

1.32. Our latest views on these matters are contained in Part 2 of this document and are summarised briefly below.

Worst served customers

1.33. We propose to introduce a "use it or lose it" allowance for DNOs to fund improvements to those customers who experience levels of service significantly worse than average (15 or more higher voltage interruptions over three years in total, with a minimum of three interruptions in each year). We believe that the total allowance for all DNOs for the five year DPCR5 period should be £42m allocated according to the number of worst served customers. This is approximately twice the amount we estimate that worst served customers will spend on quality of service improvements (through their use of system charges) over the course of both DPCR4 and DPCR5.

1.34. DNOs will be required to demonstrate a 25 per cent improvement in performance (based on a three year rolling average) for benefiting customers in order to receive ex post funding. We are proposing to allow the DNOs to spend the allowance as they see fit, and would welcome views on whether we should set a cap on the cost per benefiting customer. However, we will look to assess their relative success and innovation in approach post DPCR5. Through the customer service reward scheme we will be able to reward those companies that have innovated in how they improve the service for worst served customers or which have been particularly good at obtaining value for money.

Interruptions incentive scheme

1.35. In the December Policy Paper we set out draft targets for unplanned interruptions for each DNO for the DPCR5 period. These targets were based on the DPCR4 data to date, an updated version of the DPCR4 benchmarking methodology and a provision that targets would be at least as tight as those set for the final year of DPCR4. Since then we have received additional cost information from each of the DNOs on the forecasts costs of closing the gap between their current performance and the targets proposed in the Policy Paper.

1.36. We have reviewed the appropriate targets for DPCR5 taking into account a range of information including the benchmarking analysis, changes in performance between DPCR3 and DPCR4, forecasts costs of improvement and the willingness to pay information. If the costs of closing the performance gap are significantly greater than customer willingness to pay then we propose to reduce the performance targets[2]. We would then rely on the incentive rates to influence the DNOs' decisions on whether it is appropriate to make investments for further improvements in interruptions performance. Given the current economic climate and the impacts of the credit crunch, we are keen to aim for a scheme where the price paid by customers for improvements reflects their willingness to pay. Our latest draft targets for the unplanned element of interruptions performance are set out in chapter 7.

[2] Our Final Proposals document for DPCR4 explained that the costs to meet some of the proposed targets for supply interruptions were excessive, and therefore relaxed these targets. This affected WPD and SSE.

1.37. Our consumer research (as published in July 2008) suggested that customers were not willing to pay any significant additional amount for improvements in interruptions performance, but were also not tolerant of any decrease in performance by the DNOs. It also suggested that customers prioritised additional funding for environmental areas over customer service areas. We intend to conduct a small number of consumer focus groups in May/June 2009 to provide an update on customers' views on their priority areas. This will be particularly useful given the changing economic climate since the full research was conducted between February and April 2008. If customers' priorities have shifted significantly from their previous position then this will be useful to consider as we decide how much revenue should be exposed to the variety of incentives that we are proposing on both customer and environmental areas.

1.38. We will receive 2008-09 performance data from all of the DNOs in June 2009. This is likely to have an impact on the targets proposed, and we may need to review the targets again following analysis of this new information.

1.39. We are also considering a number of other amendments to the IIS during DPCR5 which are set out in chapter 7.

IQI, rolling forwards the RAV and equalising incentives

1.40. We have given considerable thought to the appropriate form of cost incentives to encourage DNOs to provide better forecast information across a wider range of costs, to encourage DNOs to make appropriate decisions based on whole-life costing and to avoid perverse incentives to distort cost allocations.[3]

1.41. We consider it is appropriate to equalise incentives across Network Investment, Network Operating costs and closely associated indirect costs (which together comprise network-related costs). We consider that this captures the key areas where there are economic-trade-offs and boundary issues for reporting and removes the disincentive on DNOs to consider non-network solutions such as contracting with DG and for demand side management (DSM). The only areas that we think should be excluded from the equalised incentive approach are business support costs and pension deficit repair costs. Business support costs are a recurring cost with no direct connection to the network assets and where there are no significant boundary issues with other activity costs. They will be funded entirely in the year of expenditure and effectively have an incentive rate of 100 per cent on over/under spend.

1.42. We have received positive feedback across the industry on the ideas to equalise incentives and consider that this is a significant step forwards in how we regulate these companies.

1.43. We propose to retain an Information Quality Incentive (IQI) mechanism of the form used in DPCR4 and the gas distribution price control review (GDPCR) as we consider it gives us useful information about the DNOs' expected spend. To make it difficult for DNOs to game the process by submitting a high forecast to try to influence our views, we require a robust justification for any changes to their forecasts. To retain incentive-compatibility, it makes sense to align the categories included in the IQI with those to which the equalised incentive apply.

1.44. We propose to equalise incentives for network-related costs by defining a fixed proportion of all of these costs that will be added to the RAV. This proportion will be set out in Initial Proposals as our modelling is refined. However, current indications are that it will be between 79 and 82 per cent. This will result in a similar proportion of activity costs being added to RAV as in DPCR4. Bearing this in mind, we do not envisage significant changes to the depreciation rate except for the Scottish DNOs where we are considering the reduction in revenues arising from the exhaustion of the vesting RAV.

Managing uncertainty

1.45. At present there is significant volatility in the economy which increases the uncertainty around forecasts for the DPCR5 period. This uncertainty affects both the volume and the cost of the DNOs' activities. Any material differences between the price control assumptions and outturn could result in either windfall gains or losses to DNOs and their investors. We are considering a number of mechanisms that would share this risk between the DNOs and customers to help avoid such scenarios.

1.46. Ofgem has commissioned research into mechanisms that can be used to manage input price uncertainty. This work considered mechanisms whereby we set an ex-ante allowance for input costs and expose DNOs to price risks up to a trigger point, beyond which indexation would apply for the protection of both customers and shareholders. The study recommended that any such mechanism should be limited to provide protection against materials prices due to their volatility and materiality.

1.47. We are also considering introducing capex drivers that could be used to manage volume uncertainty. We are proposing to treat sole-use connections as an excluded service but are considering including a driver for the remaining shared-use connection assets that will stay within the price control. A reopener/driver mechanism is also being considered for general reinforcement expenditure.

1.48. We will give further consideration to the appropriate balance between mechanisms to manage specific risks and a more general type of reopener proposals as this choice will interact with our decision on the cost of capital. Any decisions we make will affect the risks that companies are exposed to relative to the existing control and will therefore have an impact on our approach to setting the cost of capital.

Taxation

1.49. We propose to maintain our approach for setting tax cost allowances on an ex-ante basis with an ex-post adjustment where actual levels of gearing exceed the gearing assumption underpinning our cost of capital assessment. In December we consulted on the merits of introducing a symmetric tax trigger mechanism to mitigate DNOs' risk in the event of significant changes to UK tax legislation. We are minded to introduce such a mechanism to mitigate uncertainty. Under this revised methodology, DNOs remain responsible for managing tax risk but are de-risked from material changes outside their control.

1.50. We will maintain our policy of applying the UK standard tax rules that have passed into legislation at the time of our Final Proposals.

1.51. A key issue we are still working on is the attribution of expenditure to capital allowance pools. We have reviewed our approach and are minded to revise our methodology to follow, where practical, the common treatment followed by DNOs moderated by our interpretation where there are significant discrepancies in treatment, for which we are still seeking explanations. This should result in the DPCR5 allocations being closer to the DNOs' own treatment but on an industry normalised basis. For DPCR5, we propose to follow individual DNOs capitalisation treatment of indirect costs rather than follow the RAV rules.

1.52. We do not address the methodology for the clawback of the tax benefit arising from excess gearing as this applies to all network licensees, not just DNOs, and will be covered in a separate open letter.

Process and way forward

Stakeholder engagement

1.53. Since publication of our December Policy Paper we have continued to hold a series of industry working groups based on our key themes plus financial issues. We have used these sessions to discuss specific policy areas at a detailed, working level (for example to discuss the detailed design of specific incentive mechanisms) and to drive this work forward. While these groups are open to non-DNO stakeholders, we have a policy of inviting specific parties to discuss topics on which they have conducted their own work. This maintains the momentum of the process. We intend to continue these groups as we work towards presenting firm proposals for most policy areas in the July Initial Proposals document.

1.54. We have continued to meet with the Consumer Challenge Group to discuss our developing proposals. The Group also met with representatives from each of the DNOs in order to discuss and understand the practicalities and implications for a variety of policy areas. The Group's input has been invaluable in critiquing and developing our policy proposals, and ensuring that we continue to focus on and consider the consumer perspective. We will continue to meet with the Group throughout 2009, as we move towards both Initial and Final Proposals.

1.55. We have held a number of bilateral meetings with DNOs and other stakeholders. We remain open to further sessions if parties are interested in meeting with us.

Consultation documents

1.56. The consultation period for the Policy Paper closed on 13 February 2009. We received a number of useful responses to our December Policy Paper and we continue to use these to inform our ongoing work. All non-confidential responses are available on our website and we will provide a summary of them as an Appendix to the Initial Proposals document.

1.57. We have issued this Methodology and Initial Results paper for a four-week consultation period. Since the focus is narrower than previous consultation documents and because we are keen to consider responses and develop Initial Proposals in the light of them, we think that a shorter consultation period is appropriate.

Publication of Initial Proposals

1.58. We plan to publish our Initial Proposals document in July 2009. This document will set out our initial views on allowances and a substantive set of proposals for policy issues.

1.59. We will receive information on 2008-09 costs and updated forecasts from each of the DNOs on 26 June 2009. We intend to analyse this data at a high level on receipt. We will then make a judgement about whether the impact of the updated information would have a material impact on the draft allowances that we will present in Initial Proposals. If the changes are not material then we intend to delay publication of Initial Proposals slightly, to allow the changes to be incorporated. We would aim to publish Initial Proposals on Friday 31 July 2009.

1.60. If the changes arising from the updated information appear to be significant then we will publish Initial Proposals earlier, on Friday 17 July 2009. We would then publish a separate September Update Paper, which would accommodate the updated information and provide an update on the draft allowances presented in Initial Proposals.

RPI-X@20 Review

1.61. In March 2008, Ofgem announced the RPI-X@20 Review to review our current approach to regulating GB's energy networks and to develop recommendations for future policy. The initial consultation document was published on 27 February 2009. This document set out the rationale for the review, the objectives, the timetable and thoughts on the key issues that the review should cover. It also presented some ideas on options for change and invited views on whether the review is looking at the right issues during the 'visionary' phase of the project. The RPI-X@20 team is considering the responses received to the document and is publishing its Emerging Thinking in November 2009. Final recommendations on future regulatory frameworks for the electricity and gas transmission and distribution networks will be presented to our board in summer 2010.

1.62. We continue to work closely with the RPI-X@20 team. While any changes to the regulatory approach will not be incorporated into DPCR5, it is important that we work together as the key issues that both teams are investigating are interlinked. We will ensure that the teams are joined-up, allowing us to consider how best to take forward the issues and challenges facing the electricity distribution networks today and in the future.

2. Overview of FBPQ forecasts

Chapter Summary

This chapter presents a high level view of the forecasts submitted by the DNOs in their February FBPQs.

Question 1: What are your views on the DNO cost forecasts presented in this chapter?

Overview of FBPQ forecasts

DPCR5 forecasts - change from August submission

2.1. The DNOs have now submitted their February forecast business plan questionnaires (FBPQs) which set out cost forecasts for the 2010-2015 period. These forecasts are generally considered to be much more robust than the August FBPQs and based on more detailed bottom-up plans. The DNOs have also had the opportunity to incorporate a more up-to-date view of the impact of the economic downturn on their business plans in their February submissions. All costs are shown in 2007-08 prices unless otherwise stated.

2.2. When the DNOs submitted their August FBPQs we made it clear that we would treat them as initial forecasts and that there would not be a requirement to carry out a full reconciliation with the February FBPQ submissions. The February submissions show approximately a 10 per cent reduction in the network investment forecasts and a 1 per cent reduction in the forecasts of network operating costs, indirect costs and non-operational capex from August.

2.3. For presentation of forecasts in this chapter and for our analysis we split cost areas into Network Investment and Operational Activities. However, we are aware that there are interrelationships between those different areas such that, for example, the level of replacement of assets in DNO forecasts will be partly dependent on their assumptions for the level of maintenance of those assets.

DPCR5 forecasts - analysis against DPCR4 actual expenditure

Network investment

2.4. In analysing the DNOs' forecasts we have divided network investment forecasts into "Core" and "Non-core" expenditure. Core expenditure is non-discretionary expenditure, expenditure with higher levels of certainty and expenditure with no direct incentive mechanism. We consider core expenditure to consist of:

- Demand customer specific expenditure (associated with connections),
- General reinforcement expenditure,
- Fault level expenditure,
- Diversions expenditure,
- Asset replacement expenditure,
- Legal and safety expenditure, and
- Operational IT and telecoms (excluding BT 21st century).

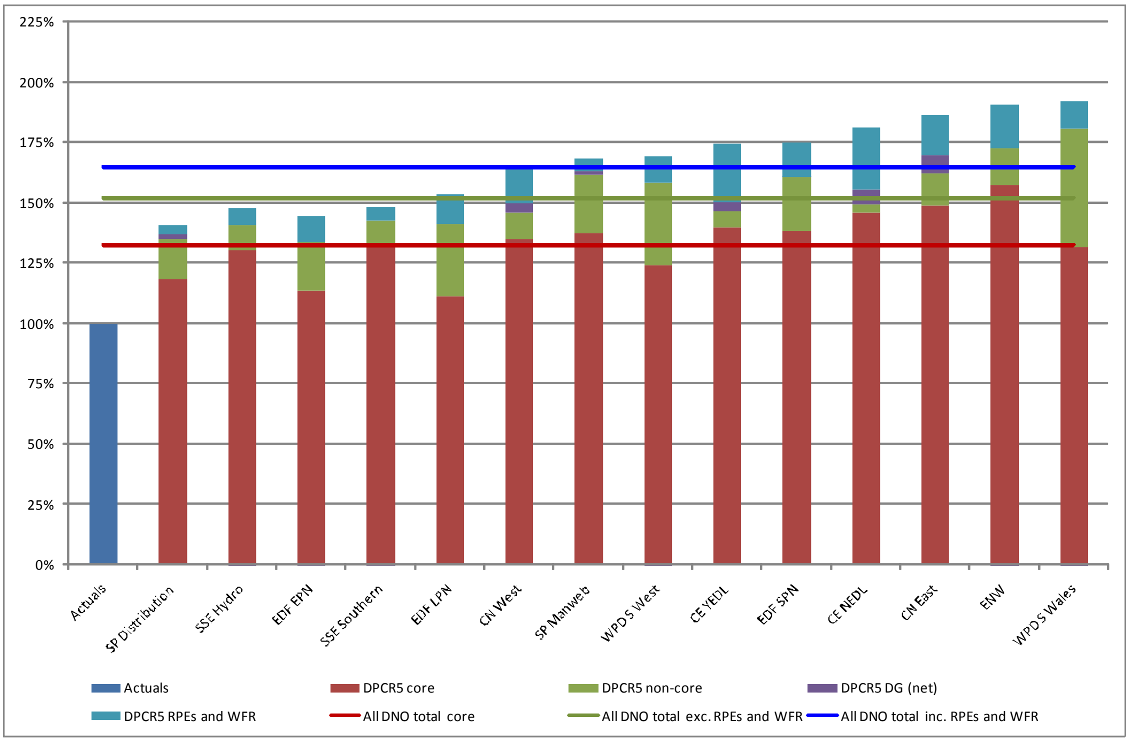
2.5. Non-core expenditure is discretionary expenditure, expenditure with higher levels of uncertainty and expenditure with a direct incentive mechanism. We consider non-core expenditure to consist of:

- Discretionary expenditure,
- Quality of service (IIS) expenditure,
- Quality of service (non-IIS) expenditure,
- Major system risks expenditure,
- BT 21st century expenditure, and
- Environmental expenditure on reducing network losses and related to connecting Distributed Generation (DG).

2.6. Using this split of costs, and indicating separately the scale of the increase due to real price effects (RPEs) and workforce renewal (WFR), the DNOs' network investment forecasts as a percentage of their expected actual[4] levels of expenditure in DPCR4 are as shown in figure 2.1.

[4] "Actual" expenditure includes three years of reported expenditure (2005-06 to 2007-08) and two years of forecast expenditure (2008-09 and 2009-10).

Figure 2.1 - Network investment DPCR5 forecast as a percentage of DPCR4 outturn



2.7. Network investment on accommodating distributed generation, less the charges paid directly by customers (DG (net)) is identified separately. Excluding RPEs and DG, core expenditure makes up 88 per cent of DPCR5 expenditure.

2.8. The forecast levels of expenditure (£million) are detailed in table 2.1.

Table 2.1 - Forecast network investment for DPCR5 against DPCR4 outturn

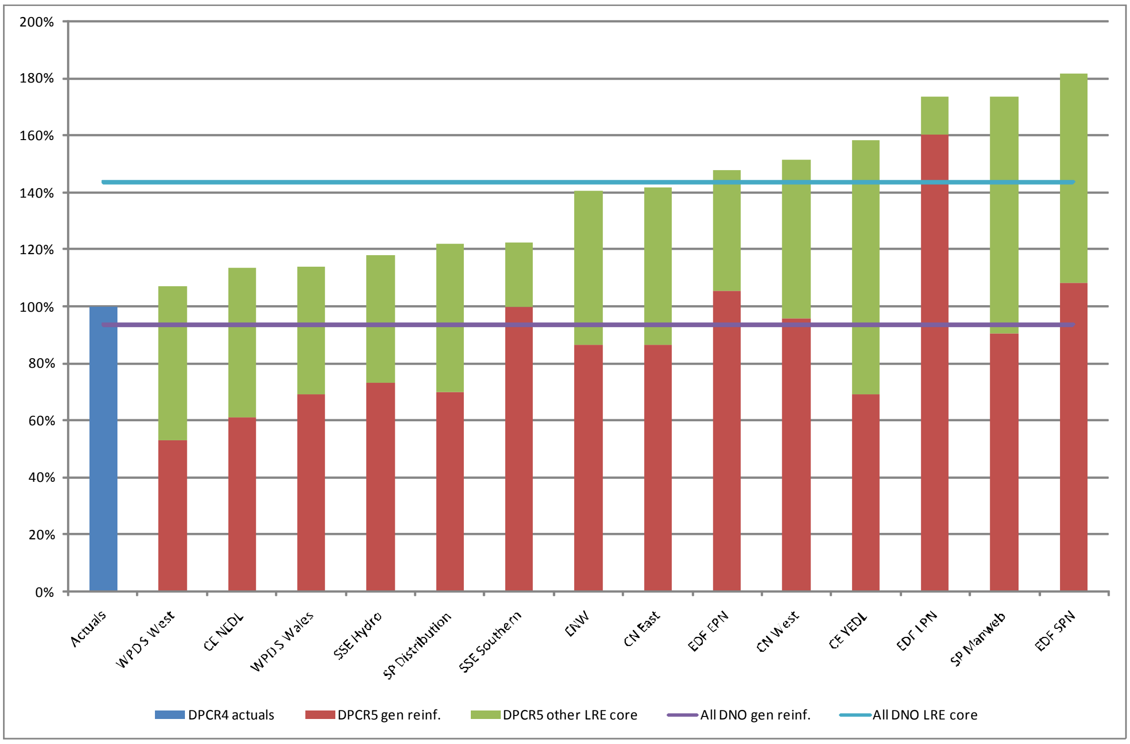
£m	DPCR4	DPCR5					Change DPCR4 to DPCR5
DNO	**5 yr**	**Core**	**Non-core**	**DG (net)**	**RPEs and WFR**	**Total**	**%**
CN West	427	577	47	17	66	706	65%
CN East	412	613	55	31	69	769	86%
ENW	356	559	55	-7	64	672	89%
CE NEDL	244	356	8	15	63	442	81%
CE YEDL	318	446	20	13	77	556	75%
WPD S Wales	138	182	67	-4	16	262	89%
WPD S West	231	287	79	-2	26	389	68%
EDF LPN	358	399	106	0	45	550	54%
EDF SPN	355	490	80	1	50	621	75%
EDF EPN	561	637	112	-1	62	810	45%
SP Distribution	351	416	58	7	14	495	41%
SP Manweb	424	583	103	5	23	714	68%
SSE Hydro	150	195	16	-6	11	216	44%
SSE Southern	436	575	47	-1	27	648	48%
Total	**4761**	**6316**	**852**	**70**	**611**	**7850**	**65%**

2.9. Across all distribution networks DNOs are forecasting a 65 per cent increase in expenditure over DPCR4. RPEs represent around 20 per cent of the increase, although assumptions on this vary widely across the DNOs. Core expenditure is forecast to increase by 46 per cent across all DNOs. This varies from 18 per cent for EDFE LPN to 69 per cent for ENW.

General reinforcement expenditure

2.10. Core net load-related expenditure, which includes general reinforcement and other core load-related Expenditure (LRE) expenditure, is as shown in figure 2.2. Other core LRE expenditure includes expenditure from customer specific demand expenditure (less direct customer contributions), diversions and fault level expenditure.

Figure 2.2 - Core net load related expenditure as a percentage of DPCR4 outturn



2.11. Across all distribution networks DNOs are forecasting a 44 per cent increase in core load related expenditure over DPCR4. This varies from a 7 per cent increase for WPD S West to an 82 per cent increase for EDFE SPN. The forecast levels of core net load related expenditure (£million) are detailed in table 2.2.

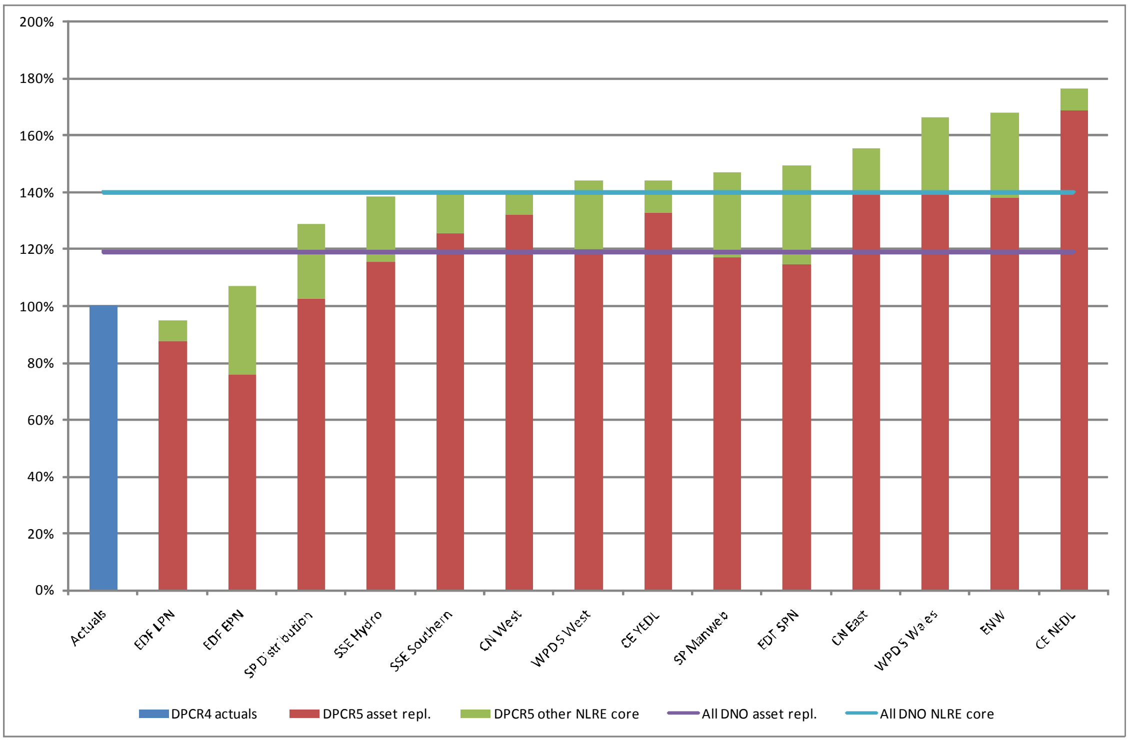
Table 2.2 - Core net load related expenditure for DPCR5 against DPCR4 outturn

£m	DPCR4			DPCR5			Change DPCR4 to
DNO	**Gen reinf**	**Other LRE**	**Total**	**Gen reinf**	**Other LRE**	**Total**	**%**
CN West	103	53	156	149	86	236	51%
CN East	112	114	225	195	125	320	42%
ENW	67	52	120	103	65	168	40%
CE NEDL	61	31	92	56	48	105	13%
CE YEDL	49	41	91	63	81	143	58%
WPD S Wales	23	19	42	29	19	48	14%
WPD S West	34	31	65	34	35	70	7%
EDF LPN	112	14	126	202	16	218	74%
EDF SPN	68	38	106	115	78	193	82%
EDF EPN	195	66	261	275	110	386	48%
SP Distribution	56	37	93	65	48	113	22%
SP Manweb	46	58	103	93	86	180	74%
SSE Hydro	28	13	41	30	18	49	18%
SSE Southern	200	2	202	202	46	247	22%
Total	**1155**	**568**	**1723**	**1612**	**862**	**2474**	**44%**

Asset replacement expenditure

2.12. Core non-load related expenditure (NLRE) is shown in figure 2.3. This includes both asset replacement and other NLRE core expenditure. The latter includes expenditure on Operational IT and Telecoms (excluding BT 21st Century expenditure) and Legal and Safety works.

Figure 2.3 - Core non-load related expenditure as a percentage of DPCR4 outturn



2.13. The majority of DNOs are forecasting an increase in core non-load related expenditure over DPCR4. One DNO, EDFE LPN, is forecasting a reduced need for investment in this category in DPCR5. The forecast levels of core non-load related expenditure (£million) are detailed in table 2.3.

Table 2.3 - Core non-load related expenditure for DPCR5 against DPCR4 outturn

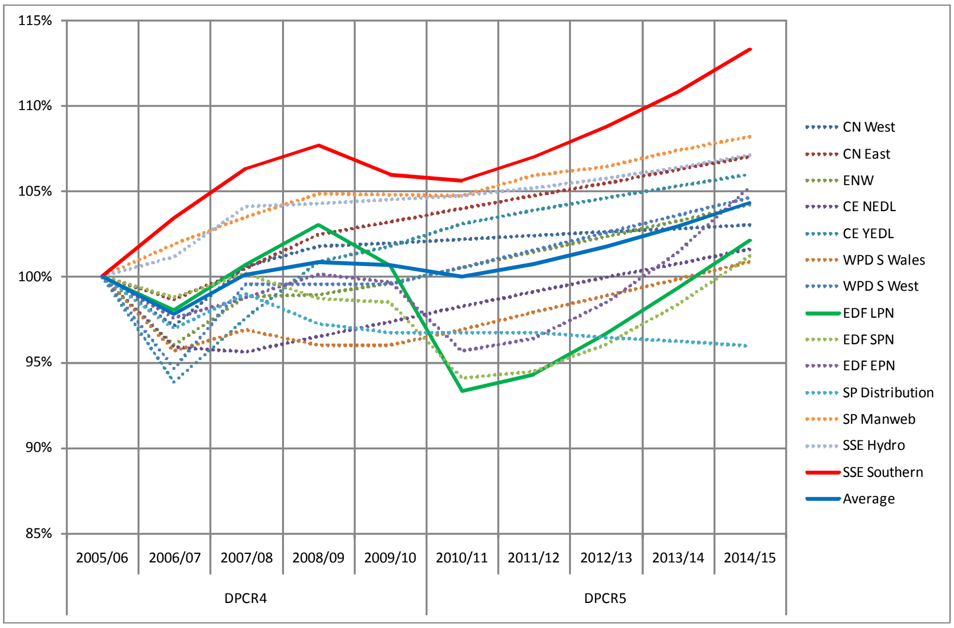
£m	DPCR4			DPCR5			Change DPCR4 to DPCR5
DNO	Asset repl.	Other NLRE	Total	Asset repl.	Other NLRE	Total	%
CN West	269	14	283	375	23	397	40%
CN East	191	10	202	283	30	314	56%
ENW	228	31	259	357	77	435	68%
CE NEDL	155	10	165	279	13	292	77%
CE YEDL	223	26	248	330	28	358	44%
WPD S Wales	84	11	95	134	25	158	66%
WPD S West	157	18	175	209	42	252	44%
EDF LPN	243	25	268	235	19	254	-5%
EDF SPN	199	36	235	269	82	351	50%
EDF EPN	255	64	319	243	99	342	7%
SP Distribution	236	23	259	266	68	334	29%
SP Manweb	252	43	295	346	88	434	47%
SSE Hydro	116	7	123	142	28	170	38%
SSE Southern	267	8	275	345	39	384	40%
Total	**2874**	**325**	**3200**	**3813**	**662**	**4475**	**40%**

DNO forecasts and assumptions

2.14. As part of their FBPQ submissions the DNOs were required to provide data regarding their assumptions and forecasts for load growth and connections activity that underpin their view of costs. The DNOs' assumptions for maximum demand[5] at a system level are shown in figure 2.4. This shows a wide variation both in historical and forecast data. Historical fluctuations are partly down to whether weather and how weather correction has been applied. Forecast data show that some DNOs are forecasting a reduction in maximum demand in the next two to three years whereas others are forecasting a constant rise, revealing different views of the length and impact of the recession and different regional factors/assumptions.

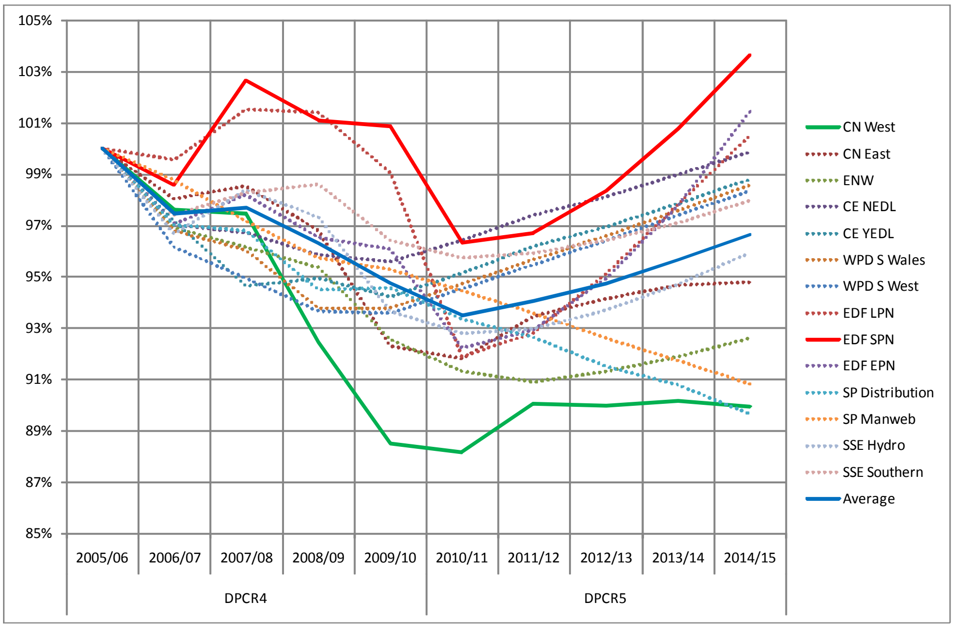
[5] Instantaneous system maximum demand as seen at entry points to the network.

Figure 2.4 - System maximum demand as a percentage of 2005-06 figure



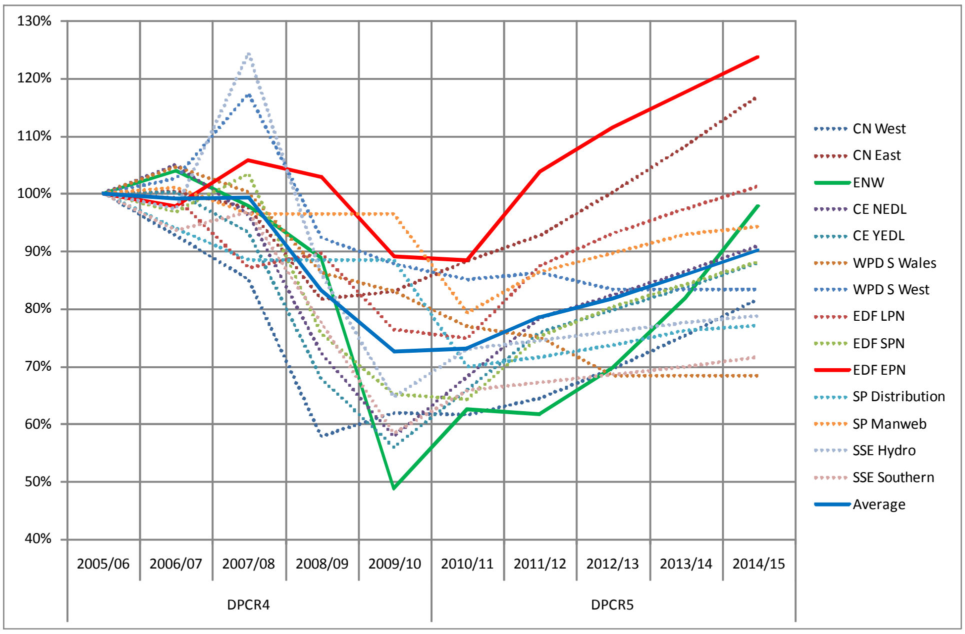
2.15. Historical and forecast data for units distributed are as shown in figure 2.5. The DNOs consistently forecast a reduction in units distributed in the next two to three years. Most forecast a recovery in the later years of DPCR5. There is a wide range of views as to the extent and length of the downturn in units distributed. SP are forecasting continued reduction of units distributed throughout DPCR5.

Figure 2.5 - Units distributed as a percentage of 2005-06 figure



2.16. Low Voltage (LV) connections (excluding IDNO connections) historic and forecast data are as shown in figure 2.6. DNOs all forecast a significant reduction in LV connections over the next two to three years but again show a wide variation in views as to how far LV connections volumes will fall from 2005-06 levels (from about 10 per cent to 50 per cent).

Figure 2.6 - LV connections (excluding IDNOs) as a percentage of 2005-06 figure



Operational Activities

2.17. To analyse Operational Activities we have divided forecasts into four distinct areas:

- Network Operating Costs,
- Indirect Costs,
- Non-Operational Capex, and
- Real Price Effects (RPEs).

2.18. Network Operating Costs include the activities of Faults, Inspections & Maintenance and Tree Cutting.

2.19. Within the FBPQs we have split indirect costs between Engineering Indirects, Network/Investment Support, and Business Support. We have combined those into one Indirect Activities figure for presenting the data in this chapter. These groupings of activities reported in the FBPQ are:

- Engineering Indirects: Network Design, Project Management and Engineering Management & Clerical Support.
- Network/Investment Support: Network Policy, Control Centre, System Mapping, Call Centre, Stores, Vehicles & Transport and Health, Safety & Operational Training.

- Business Support: IT & Telecoms, Property Management, HR & Non-Operational Training, Finance & Regulation and CEO etc.[6]

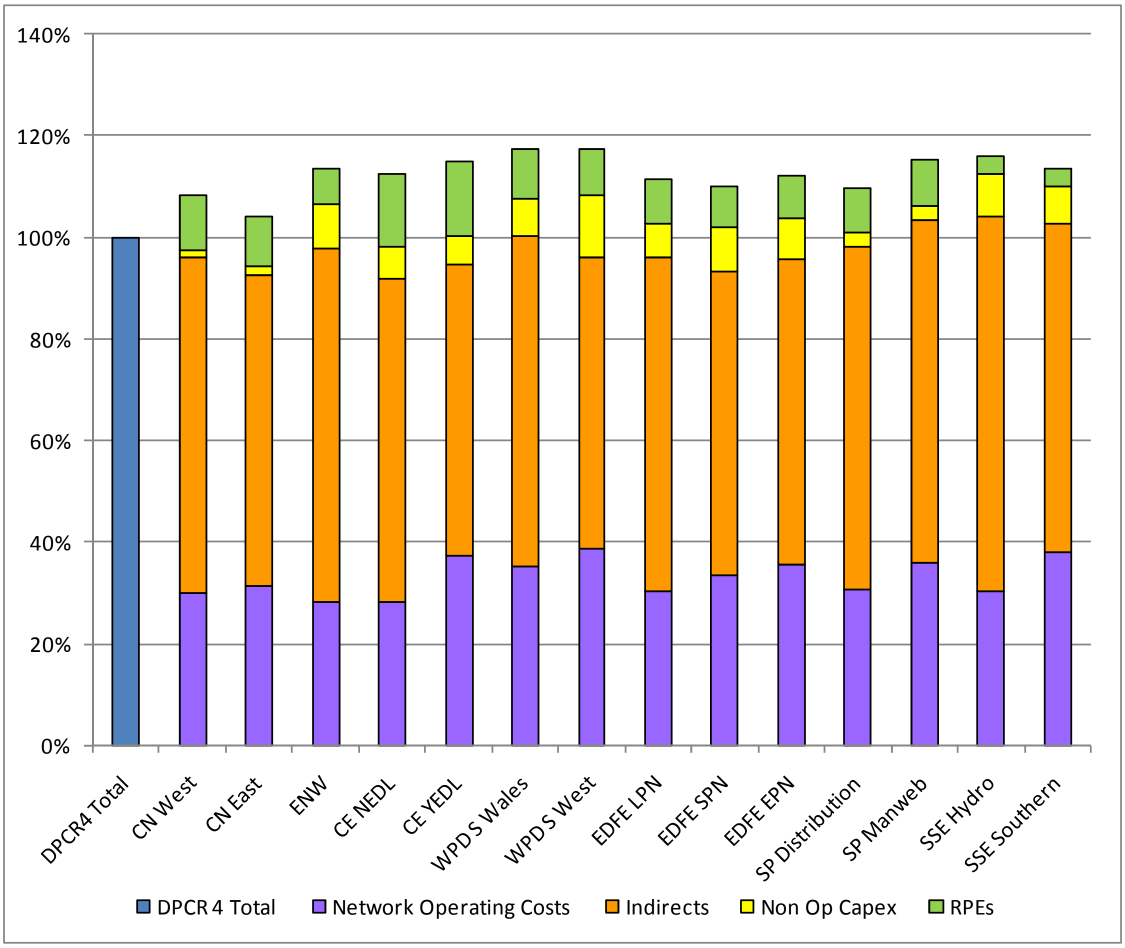
2.20. Non-Operational Capex includes such items as non-operational IT investment, purchases of buildings and the purchase of other items such as vehicles, tools and machinery.

2.21. The DNOs are forecasting a total increase in Operational Activities of 14 per cent for the DPCR5 period compared with DPCR4. The increase for individual DNOs ranges from 6 per cent to over 19 per cent. If we exclude RPEs the total forecast increase for the DNOs is 5 per cent, but ranging from a fall of 4 per cent to an increase of 13 per cent.

2.22. Figure 2.7 shows the overall percentage change in costs from DPCR4 to DPCR5 split between Network Operating Costs, Indirect Costs, Non-Operational Capex and RPEs.

[6] For more detail of the definition of each of these activities refer to 'Electricity Distribution Price Control Review: Price Control Cost Reporting Rules: Instructions and Guidance April 2009' available on the Ofgem website.

Figure 2.7 - Network Operating Costs, Indirects and Non-Operational Capex as percentage of DPCR4 totals



2.23. The following table explains the numbers behind that chart in more detail.

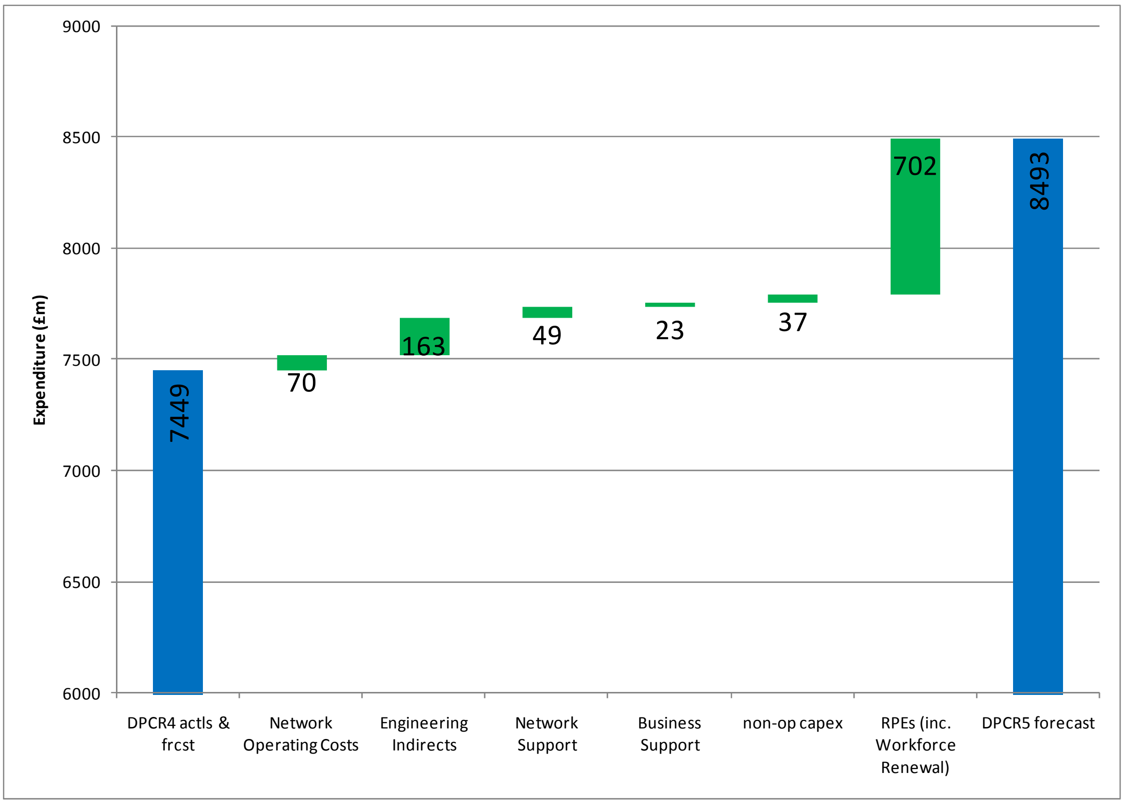
Table 2.4 - DPCR5 forecast expenditure for Operational acticities compared to DPCR4 outturn

		DPCR 5					
DNO	DPCR 4 Total	Network Operating Costs	Indirects	Non Op Capex	RPEs	Total	DR4 to DR5
CN West	604	182	398	9	74	664	10%
CN East	601	190	366	10	68	634	6%
ENW	617	173	430	53	61	717	16%
CE NEDL	387	109	247	23	60	440	14%
CE YEDL	480	179	275	28	78	560	16%
WPD S Wales	321	113	209	23	36	381	19%
WPD S West	443	171	254	55	49	528	19%
EDFE LPN	553	169	362	37	65	632	14%
EDFE SPN	548	184	327	47	64	622	13%
EDFE EPN	902	321	543	73	102	1039	15%
SP Distribution	499	154	336	14	48	553	11%
SP Manweb	493	177	332	14	52	575	17%
SSE Hydro	336	102	248	29	14	392	17%
SSE Southern	664	252	428	50	26	756	14%
Total	**7449**	**2476**	**4756**	**464**	**798**	**8493**	**14%**

2.24. The forecast costs for Indirect Activities represent 56 per cent of the total forecast Operational Activities for the DNOs with Network Operating Costs the next highest at 29 per cent. These figures can mask significant ranges across the DNOs, e.g. Indirects represent only 57 per cent of DPCR5 forecast expenditure for CE YEDL but 74 per cent of expenditure for SSE Hydro.

2.25. The chart and table above do not show the changes in the various cost categories for the industry in DPCR5 compared to DPCR4. This information is presented in figure 2.8.

Figure 2.8 - Changes in key cost areas for DPCR5 compared to DPCR4



2.26. By far the largest increase in forecast cost arises from increases in RPEs (including workforce renewal) of £702m (67 per cent) with the next largest increase due to Engineering Indirects of £163m (16 per cent). The increase in Network Operating Costs of £70m over the five year period represents just 7 per cent of the total increase compared to DPCR4.

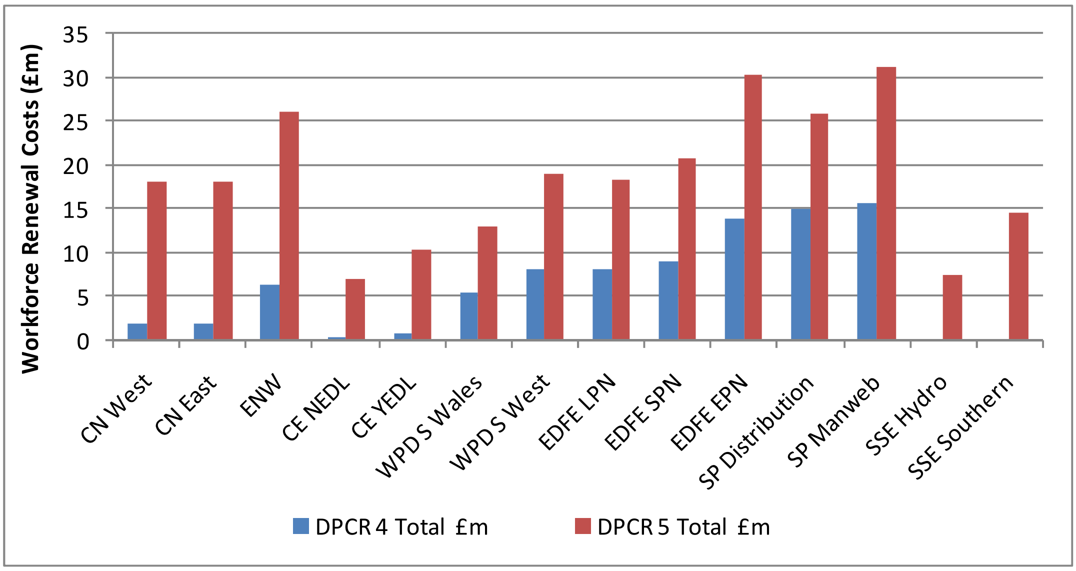
2.27. We have commissioned work from our own consultants to assess the work the DNOs have undertaken to determine real price effects. This is discussed further in chapter 6

Workforce Renewal

2.28. The cost increases reported above include a large increase in the costs for Workforce Renewal. Workforce Renewal includes the costs of replacing leaving staff and increasing the workforce to manage the increase in workload forecast for DPCR5. Not only are the DNOs forecasting further increases in workload in DPCR5 but they are also forecasting a large increase in workforce retirements because of the numbers of staff recruited during the 1950's and 1960's who are now approaching normal retirement age.

2.29. Workforce Renewal costs have been reported in the FBPQs for both Network Investment and Operational Activities. Figure 2.9 shows the reported costs for Workforce Renewal in total for DPCR4 and DPCR5.

Figure 2.9 - Workforce Renewal actual and forecast costs (£ million 2007-08 prices)



2.30. The chart above shows that the DNOs are forecasting to spend significantly more on workforce renewal over the DPCR5 period that was spent in DPCR4. Table 2.5 below gives more detail of the costs the DNOs have reported and splits the costs between Network Investment and Operational Activities.[7]

[7] We are due to receive further information from SSE on the costs and FTEs for the DPCR4 period.

Table 2.5 - Reported Workforce Renewal costs split by Network Investment and Operational Activities

DNO	DPCR4			DPCR5		
	Network Investment	Operational Costs	DPCR 4 Total £m	Network Investment	Operational Costs	DPCR 5 Total £m
CN West	1	1	**2**	10	8	**18**
CN East	1	1	**2**	9	9	**18**
ENW	2	5	**6**	9	17	**26**
CE NEDL	0	1	**1**	2	5	**7**
CE YEDL	0	1	**1**	3	8	**11**
WPD S Wales	3	3	**6**	8	5	**13**
WPD S West	4	4	**8**	11	8	**19**
EDFE LPN	1	8	**8**	2	16	**18**
EDFE SPN	1	8	**9**	3	18	**21**
EDFE EPN	1	13	**14**	4	27	**30**
SP Distribution	11	4	**15**	20	6	**26**
SP Manweb	12	4	**16**	25	7	**31**
SSE Hydro	0	0	**0**	5	2	**7**
SSE Southern	0	0	**0**	11	4	**15**
Totals	**36**	**51**	**87**	**122**	**139**	**261**

Efficiencies

2.31. Some DNOs have forecast non-specific efficiency savings within their FBPQ while for others these assumptions may be included but are not specified in the tables or within the commentary. We will undertake further work prior to Initial Proposals to identify what the other DNOs have assumed for efficiency savings in their forecasts. We will also amend the FBPQ for the June submission to require DNOs to identify specific projects and general assumptions that will result in efficiency savings for their businesses. This is discussed further in chapter 3.

Quality of service

2.32. The DNO base case position for 2014-15 represents the unplanned customer interruptions (CIs) and customer minutes lost (CMLs) as a result of asset replacement expenditure. The DNO quality of service case position for 2014-15 reflects the DNO's view of the unplanned CI and CML performance that would be delivered by additional Quality of Service projects they believe are appropriate to be implemented during DPCR5.

Table 2.6 – DNO customer interruption forecasts

CI	DNO base case	DNO QofS case
	2014-15	
CN West	111.2	100.1
CN East	75.6	70.6
ENW	49.4	45.0
CE NEDL	63.8	63.5
CE YEDL	74.2	71.1
WPD S Wales	79.4	73.0
WPD S West	71.9	70.9
EDFE LPN	34.0	33.0
EDFE SPN	78.5	74.0
EDFE EPN	72.7	69.2
SP Distribution	58.7	57.0
SP Manweb	41.7	40.3
SSE Hydro	69.8	69.8
SSE Southern	71.1	71.1

Table 2.7 – DNO customer minute lost forecasts

CML	DNO base case	DNO QofS case
	2014-15	
CN West	89.7	79.8
CN East	65.5	57.3
ENW	48.2	44.7
CE NEDL	58.4	55.6
CE YEDL	68.9	64.2
WPD S Wales	40.6	37.8
WPD S West	42.7	42.2
EDFE LPN	39.6	38.9
EDFE SPN	87.1	82.1
EDFE EPN	62.6	54.0
SP Distribution	54.4	44.4
SP Manweb	53.7	45.7
SSE Hydro	59.3	59.3
SSE Southern	64.8	58.8

Environmental - losses

2.33. The DNOs have provided markedly different forecasts of the impact of their non discretionary expenditures on losses (as summarised in table 2.8[8]). Forecasts are split between those predicting a losses increase (ranging from 0.5 per cent to 4.7 per cent of current levels of losses) and those predicting a reduction (ranging from 0.4 per cent to 3.1 per cent).

Table 2.8 - Summary of DNO forecasts of the impact of their FBPQ non discretionary expenditures on losses over DPCR5

DNO	Change in losses over DPCR5	Equivalent percentage of current losses	Equivalent percentage of current units distributed
	MWh	%	%
CN West	36,234	3.0%	0.12%
CN East	53,184	4.4%	0.20%
ENW	5,904	0.5%	0.02%
CE NEDL	- 23,581	-2.6%	-0.14%
CE YEDL	- 43,360	-3.1%	-0.18%
WPD S Wales	31,777	4.7%	0.25%
WPD S West	47,096	4.6%	0.31%
EDFE LPN	- 7,484	-0.4%	-0.03%
EDFE SPN	- 12,712	-0.9%	-0.06%
EDFE EPN	- 15,354	-1.1%	-0.04%
SP Distribution			
SP Manweb			
SSE Hydro	- 4,999	-0.7%	-0.06%
SSE Southern	- 33,767	-1.5%	-0.10%
Total	32,938		0.01%

[8] To provide context we have calculated the forecast loss changes as a percentage of each DNO's 2007-08 level of losses, and as a percentage of the units distributed through each network in 2007-08. SP Energy Networks stated that they were unable to provide forecasts due to data unavailability. It should be noted that we are currently analysing these forecasts and will be liaising with the DNOs to understand their assumptions and justifications.

3. Operational cost assessment methodology and results

Chapter summary

This chapter provides an update on the methodology for the DPCR5 assessment of Network Operating Costs, Engineering Indirects, Network Support and Business Support costs.

Question 1: Have we exposed the correct costs to comparative benchmarking?
Question 2: Do you agree with the assumptions we have made for our core analysis?
Question 3: What are the appropriate cost drivers for each of the cost groupings?
Question 4: How should we determine baselines for the costs excluded from comparative benchmarking?
Question 5: How should we treat atypical costs in the price control settlement?
Question 6: What weight should we give to the benchmarking relative to other considerations?

Introduction

3.1. The main purpose of this chapter is to set out our overall approach for the assessment of Operational Costs; consisting of Network Operating Costs (NOCs) such as Inspections and Maintenance, Engineering Indirect Costs (EICs) for example Project Management, Network Support Costs (NSCs) such as the control centre and Business Support Costs (BSCs) such as Finance and Regulation, together with our initial results.

3.2. Our overall approach to the assessment of these costs for the DPCR5 settlement is to benchmark costs, where appropriate, based on historical cost data and roll forward those results in line with our views on the scope for further efficiencies and the additional requirements on the DNOs over that period. Our work to date on the potential for efficiencies across the industry is explained in chapter 6. We will be discussing the potential for DNO specific efficiency savings in this area with the DNOs over the coming months and will include those in the Initial Proposals document.

3.3. The ultimate output of the benchmarking and other work in this area will be Ofgem's view of the efficient level of costs for each DNO which will form what we call a baseline for Operational Costs. The actual allowances will be determined through the IQI process and will be partly driven by the DNO view of the costs they need over the DPCR5 period. This is a change in the approach at previous price controls and ensures that DNOs have a greater influence over the ultimate allowance and incentive rates that apply.

3.4. The results of our comparative benchmarking work suggest some significant differences in efficiency across the DNOs. We have found that the ranking of the DNOs is very similar across a broad range of analysis but the magnitude of the differences is sensitive to a number of factors such as potential adjustments for regional contractor and labour costs, costs for very urban or sparse areas and differences in in-sourcing and out-sourcing approaches.

3.5. We set out below an overview of the key issues that have arisen in relation to our approach, and their materiality. We are consulting on how we should address these issues to arrive at a view of the operational costs the DNOs are allowed to recover from customers over the DPCR5 period. The results included in this chapter represent a snapshot of our analysis at a point in time. We have had discussions with the DNOs since the December document and have taken views expressed to us into account in developing our analysis. We will continue discussions with DNOs and other stakeholders as we develop our analysis to inform the Initial Proposals baselines.

3.6. Since the December Document:

- We have reached a firm view on how certain costs will be treated for the purposes of benchmarking such as costs relating to severe weather events and related party margins,
- Some DNO groups have identified DNO specific costs. We set out analysis on the materiality of these issues and consult on how it is appropriate to address them for Initial Proposals,
- We have further developed our understanding of cost drivers, and thereby cost groupings, and
- We have changed the treatment of vehicle costs. We now propose to 'absorb' the costs within the direct costs of network investment and network operating costs.

Background

3.7. We based our cost assessment at DPCR4 on a single year's data provided by the DNOs in their Historical Business Plan Questionnaires (BPQs). Ofgem spent significant resources during DPCR4 normalising and reviewing this data because of the weaknesses in the submitted data. This precluded the use of more disaggregated benchmarking analysis.

3.8. One of the key lessons learned at DPCR4 was the benefit of collecting and reviewing cost data on an annual basis. We now capture cost data via a regulatory reporting pack (RRP) which includes both detailed cost spreadsheets and associated narrative. We now have three more years of data (2005-06 to 2007-08) to use as part of DPCR5. This provides the opportunity for improved benchmarking and modelling that was not possible at DPCR4. For example, we are now applying panel data techniques to assess network operating costs and network investment over three years rather than simply relying on a single year's data.

3.9. We have also built up an in-house team with a greater knowledge of the operations of distribution businesses and understanding of their costs which has been gained from the annual review and visits to the DNOs as part of the RRP process. We are better placed than in previous reviews to make a judgement on the necessity and efficiency of the reported costs and forecasts from the DNOs.

3.10. We have carried out detailed work to get a better understanding of the true drivers of costs within DNOs and appreciate the work undertaken by the DNOs to take this forwards. While the DNOs and ourselves have not been able to reach full agreement on the exact driver metrics to use in our analysis we have developed an understanding across the industry far beyond that which was available at DPCR4.

3.11. We have also developed our knowledge of benchmarking techniques and methodologies applied by other regulators. We have appointed an academic advisor to guide us through the process of undertaking comparative analysis through benchmarking.

3.12. We are confident that the progress we have made over the past four years means that we have much more robust analysis available to us for discussions with the DNOs and to develop the Initial Proposals baselines for DPCR5.

Cost Assessment Methodology

3.13. The key to setting allowances for the DNOs for the DPCR5 period is our understanding of the cost requirements for the DNOs. We use comparative benchmarking analysis to inform our view of the efficiency of the actual costs each DNO has incurred and then apply our understanding of the forecast changes to those costs over DPCR5. However, comparative analysis is not appropriate for all costs and for these we rely on other techniques. We have appointed consultants to carry out a review of non-operational IT and property costs and their initial reports describing their methodology for completing their work are included as Appendices to this document.

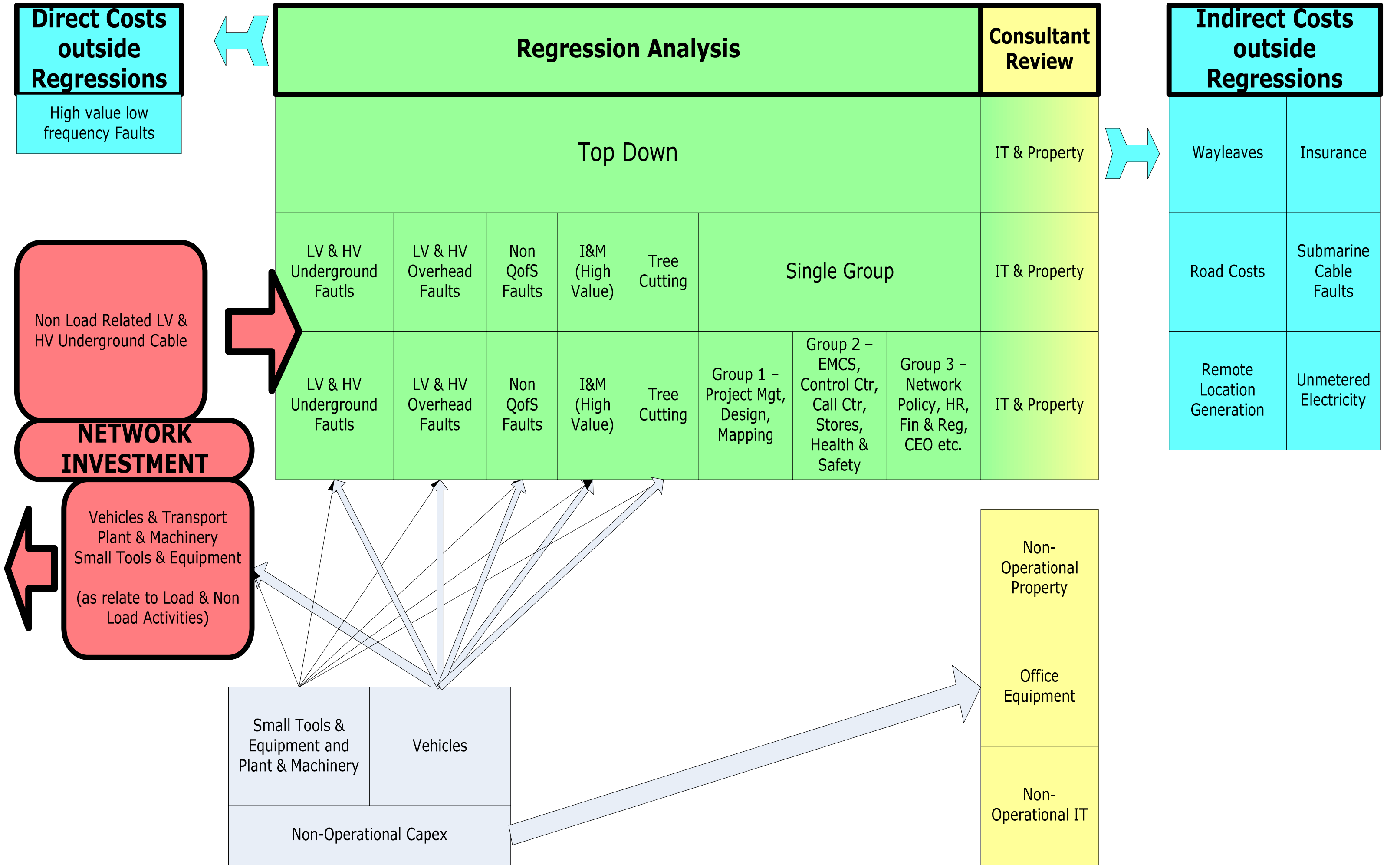
3.14. We have excluded some other costs from the comparative benchmarking, e.g. Wayleaves, remote location generation and unmetered electricity, and will review the historical and forecast costs to determine efficient spend without using comparative benchmarking. Further details of these costs are included in this chapter and in more detail in appendix 5.

3.15. Figure 3.1 provides an overview of our approach to the cost assessment. We have highlighted in green the areas for which comparative analysis (regressions) has been undertaken and the different levels of aggregation at which the analysis has been done (i.e. overall (top down) regression, a single group for indirects and five groups for network operating costs and eight groups for network operating costs and indirects). Figure 3.1 also shows those costs that are being assessed by consultants (yellow) and those costs for which we think comparative analysis is not appropriate (pale blue).

3.16. We have reallocated Vehicles & Transport, Small Tools & Equipment and Plant & Machinery costs within the costs of direct activities. It is clear from our discussions with the DNOs that these costs are very closely related to the direct activities and for some there are difficulties in extracting the costs from those activities. We now think it is inappropriate to split those costs from the activities they support and benchmark them separately. We will be discussing with the DNOs the appropriate adjustment to make for these costs over the coming months but for the purposes of this document we have pro-rated the costs by the labour costs they support.

3.17. We have applied comparative benchmarking to £1.1bn of the costs the DNOs incurred in 2007-08. This represents 75 per cent of the total operational costs (including Non-operational capex) of £1.4bn reported for 2007-08 by the DNOs.

Figure 3.1 - Representation of cost analysis



Benchmarking

3.18. We will use comparative benchmarking to inform our judgement of the level of costs allowances rather than setting those allowances directly. We use a variety of techniques for that benchmarking to ensure we obtain a range of outcomes that are not skewed by any one particular approach.

3.19. In line with the advice from our academic advisor and developments in benchmarking used by other regulators we are now applying time series panel data regression techniques using three years' data (2005-06 to 2007-08) as the core of our comparative benchmarking[9]. When we receive the updated FBPQ in June 2009 we will have a fourth year (2008-09) of actual costs so four years of data will inform our views for Initial and Final Proposals.

3.20. We are considering DNO specific adjustments prior to carrying out our benchmarking and these do not form part of the models that we estimate. Our models do consider time specific effects in what is known as a time fixed effects approach[10]. In addition, we have begun the process of applying Data Envelopment Analysis (DEA)[11] as a cross-check on the results. We undertook a similar cross-check using DEA at DPCR4.

3.21. We consider it important to carry out our cost analysis at various levels of disaggregation. The advantage of more detailed analysis (bottom-up) is that it allows us to consider the appropriate cost drivers for particular cost groups. The benefit of more aggregated or top-down analysis is that it potentially better capture trade-offs between various activities. As Figure 3.1 shows we are undertaking regressions at three different levels

3.22. Table 3.1 shows our activity groupings and the drivers we have used for our base analysis for each. The table also shows the alternative drivers used to test the results of the base (core) regressions.

[9] Time series panel data regressions are estimated using data from more than one time period. The additional data can allow better estimation of the effect of cost drivers than is possible using a single year's data.

[10] This approach includes parameters that measure the differences in costs between years. These differences in costs will reflect a combination of factors such as changes in input prices and industry-wide improvements in efficiency.

[11] DEA is a non-statistical approach that can be used for efficiency analysis. A frontier against which efficiency can be assessed is fitted to the data based on the input and output combinations observed in the data.

Table 3.1 - Cost Drivers used for core regressions of cost groupings

Drivers		Base Regressions	Alternative Regressions
LV & HV Underground Faults (including Non-Load LV & HV Underground Capex)		Total LV & HV Underground Faults	
LV & HV Overhead Faults		Total LV & HV Overhead Faults	
Non-QofS Faults		Number of Customers	
Inspections & Maintenance		Asset Hours Work Driver for Inspections & Maintenance	
Tree Cutting		Spans Cut	
Group1	Network Design, Project Management, System Mapping	Total Network Investment spend (£m)	MEAV, Volume/Unit Cost
Group2	Engineering Management & Clerical Support, Control Centre, Call Centre, Stores and Health & Safety & Operational Training (excluding apprentice costs)	Total Direct Costs [less non-operational capex] (£m)	MEAV
Group3	Network Policy, HR & Non-Operational Training, Finance & Regulation and CEO etc.	Network MEAV	DPCR4 CSV
Single Group	As for Groups but amalgamating the three groups of costs into a single regression.	Composite Driver of drivers for Group1, Group2 and Group3	
Top Down	Single regression of all the above costs.	Composite Driver of drivers for Single Group, Faults, I&M and Tree Cutting	

3.23. We have considered alternative drivers for some of the groups of indirects to test the impact of them on the results. We present the results showing the impact of changing the drivers in appendix 5. We welcome views on the appropriate drivers for each cost grouping.

3.24. We have agreed to share our comparative benchmarking work with the DNOs to allow them to repeat the analysis and to identify any errors that may exist. We have already begun the process by sharing the base cost data for the analysis across all the DNOs.

Assumptions for the benchmarking

3.25. We have been considering the appropriate adjustments to costs prior to carrying out the benchmarking with the DNOs and other stakeholders. This includes whether certain elements of costs such as severe weather and related party margins (i.e. those margins earned in relation to distribution activities by businesses within the same ownership group as the DNO) should be included or excluded and whether specific adjustments need to be made for certain DNOs. In some cases we have come to a view on whether to include or exclude those costs and whether to make normalisation adjustments. In other cases we are continuing our discussions with the DNOs and have made an assumption for the presentation of a base set of results in this document.

3.26. For our core comparative benchmarking we have:

- Included related party margins,
- Included severe weather atypical events,
- Excluded pensions,
- Excluded costs for 'alliance' contracting (i.e. where contractors have an 'open book' arrangement such that contractor costs are reported as Indirect costs rather than Network Investment or Network Operating Costs),
- Adjusted Labour and Contractor costs for EDFE LPN, and
- Made no singleton adjustment

3.27. The following paragraphs provide a brief overview of each of the issues where we have come to a firm view of treatment for comparative benchmarking. The other assumptions are discussed further in the results section of this chapter. We welcome comments on the assumptions we have made for our core analysis.

Related Party Margins

3.28. We consider that it is appropriate to include the related party margins within the comparative benchmarking of the DNOs. The results of the comparative analysis should highlight whether there are any inefficient margins with the DNOs' costs. Further, the analysis that we have carried out highlights that there is little difference in the results between including and excluding related party margins. Related party margins reported by the DNOs in 2007-08 were £29.7m which represents 2.1 per cent of the total costs included within the core comparative benchmarking.

Severe Weather Atypical Costs

3.29. As we are using a panel data approach to carry out benchmarking over several years we consider that it is appropriate to include severe weather expenditure in the costs for comparative benchmarking. The analysis that we have carried out suggests that there is very little impact from excluding such events. We are giving separate consideration as to whether it is appropriate to make an allowance for very large 1-in-20 severe weather events as we did in DPCR4. Severe weather atypical costs reported by the DNOs in 2007-08 were £8.9m representing 0.6 per cent of the costs included within the core comparative benchmarking.

Singleton Adjustment

3.30. In the DPCR4 settlement we allowed a specific singleton adjustment but stated our expectation that the singleton DNOs should improve their efficiency over the DPCR4 period to catch-up with benchmark performance. Our current thinking is that it is inappropriate to include any further singleton adjustments. We would welcome views on this.

Applying frontier analysis to top-down

3.31. We have listened to DNO concerns regarding the potential for 'cherrypicking' with comparative benchmarking on a disaggregated basis.

3.32. We will develop our methodology further before the Initial Proposals document but our current view is that we will apply an upper quartile to regressions at a 'top-down' level rather than for the disaggregated regressions. We will then consider the impact this has on the output of that analysis to determine how to apply a similar overall adjustment to the results of the other analysis.

Data Envelopment Analysis

3.33. We have undertaken Data Envelopment Analysis (DEA) analysis of the costs used in the comparative benchmarking on a top-down basis using a Variable Returns to Scale (VRS) functional form. We have presented the results of the DEA analysis together with a comparison of the rankings with the results of our core linear and log-log regressions in appendix 5.

3.34. The DEA methodology provides results in a different form to those presented for the regressions so we have presented the results of DEA in terms of the ranking given to each of the DNOs. The overall rankings are very similar to the other analysis we have undertaken, particularly the log-log analysis, giving us further confidence in our analysis.

Alternative Approaches

3.35. Central Networks and EDF Energy have presented papers to us suggesting alternative approaches to comparative benchmarking based on using total costs to determine comparative efficiency. We have reviewed the paper and discussed the issues contained in the paper with Central Networks and we recognise the benefits of their approach. To date we have not had the opportunity to rigorously test the methodology or repeat the analysis. We have not included the results of Central Network’s analysis in this document but we will continue our discussions with them to explore how we might use some of their work to develop our own methodology as a check on the results of our core analysis.

3.36. We have also received papers from some other DNOs suggesting alternative approaches to our analysis, including different views of the grouping of activities, which we have reviewed and considered.

Comparative benchmarking results

Core benchmarking results

3.37. This section provides a summary of the core analysis results as defined earlier in this chapter. Further details of the analysis have been included in appendix 5. We have presented the results in this document in the form of a percentage Benchmarking Score that provides a view of relative performance. This score (a lower score is better) is calculated by the dividing the actual reported cost, after normalisation adjustments, by the modelled cost,

$$\text{Benchmarking Score} = \frac{\text{Actual Costs}}{\text{Modelled Costs}}$$

3.38. Table 3.2 provides the benchmark scores for the regressions on a per DNO basis and provides an average of the scores. The results of the core regressions on a per DNO Group basis are included in appendix 5.

Table 3.2 Results of the benchmarking for our base scenario on an individual DNO basis

	Linear			LogLog			
DNOs	Top Down	Single Group	Groups	Top Down	Single Group	Groups	Average Score
CN West	125%	123%	123%	123%	125%	124%	124%
CN East	103%	102%	102%	99%	103%	102%	102%
ENW	105%	105%	105%	103%	100%	101%	103%
CE NEDL	94%	93%	93%	98%	97%	96%	95%
CE YEDL	105%	106%	107%	103%	101%	102%	104%
WPD S Wales	80%	75%	75%	90%	84%	83%	81%
WPD S West	89%	86%	87%	92%	91%	91%	89%
EDFE LPN	110%	101%	100%	115%	101%	100%	104%
EDFE SPN	102%	100%	100%	103%	103%	103%	102%
EDFE EPN	107%	112%	112%	101%	108%	108%	108%
SP Distribution	118%	116%	116%	118%	115%	115%	116%
SP Manweb	100%	102%	102%	100%	103%	102%	101%
SSE Hydro	68%	65%	66%	78%	74%	74%	71%
SSE Southern	81%	89%	90%	77%	82%	83%	84%

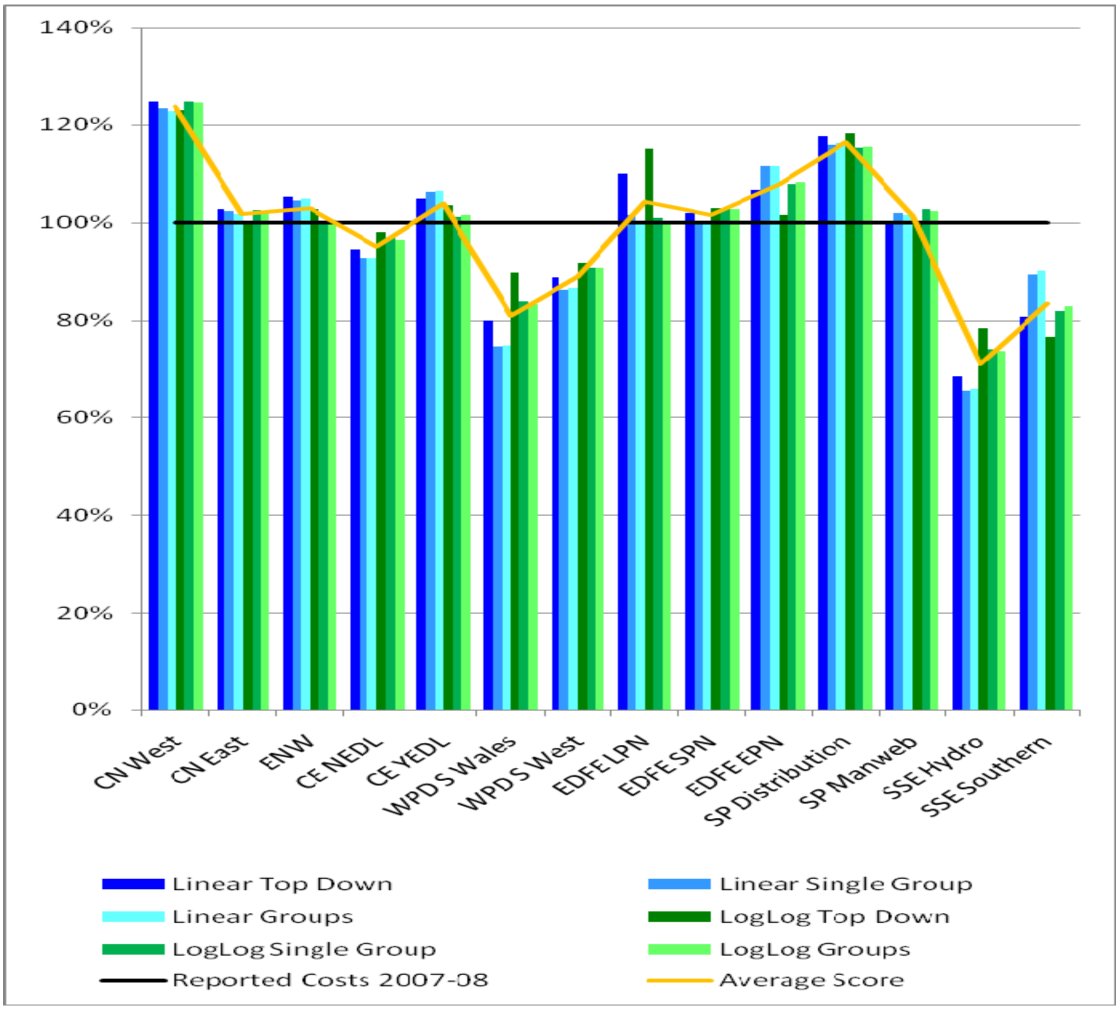
3.39. The table shows that the different methodologies for the core benchmarking exercises on an individual DNO basis results in broadly consistent results with SSE and WPD DNOs appearing to perform well. We have included 'traffic light' formatting to demonstrate the comparative results for the DNOs consistent with other data in this document. There is also a consistent message from the results that CN West, EDFE EPN and SP Distribution appear to be performing poorly compared to other DNOs.

3.40. We have carried out regressions on an individual DNO Group basis but have found that the results are less consistent. For DNO Group regressions there are much fewer reference points (only 21 over three years) and this results in less statistically robust results. We discuss this further in appendix 5.

3.41. Figure 3.1 shows the same information as table 3.2 but in graphical form. From the chart it is clear that while the benchmarking scores do alter for the different levels of disaggregation and the functional form (either linear or Log-Log) the relative benchmarking scores for the DNOs are very similar.

3.42. In the chart the bars represent each of the six different results and the gold line represents the Average score per DNO as noted in table 3.1.

Figure 3.2 - Results of the benchmarking for our base scenario- actual costs as a percentage of the benchmark



3.43. We have agreed a set of statistical tests with our academic advisor and run those tests on the core regressions. The results of these tests, and the conclusions we have taken from them, are included in appendix 5.

Scenario results

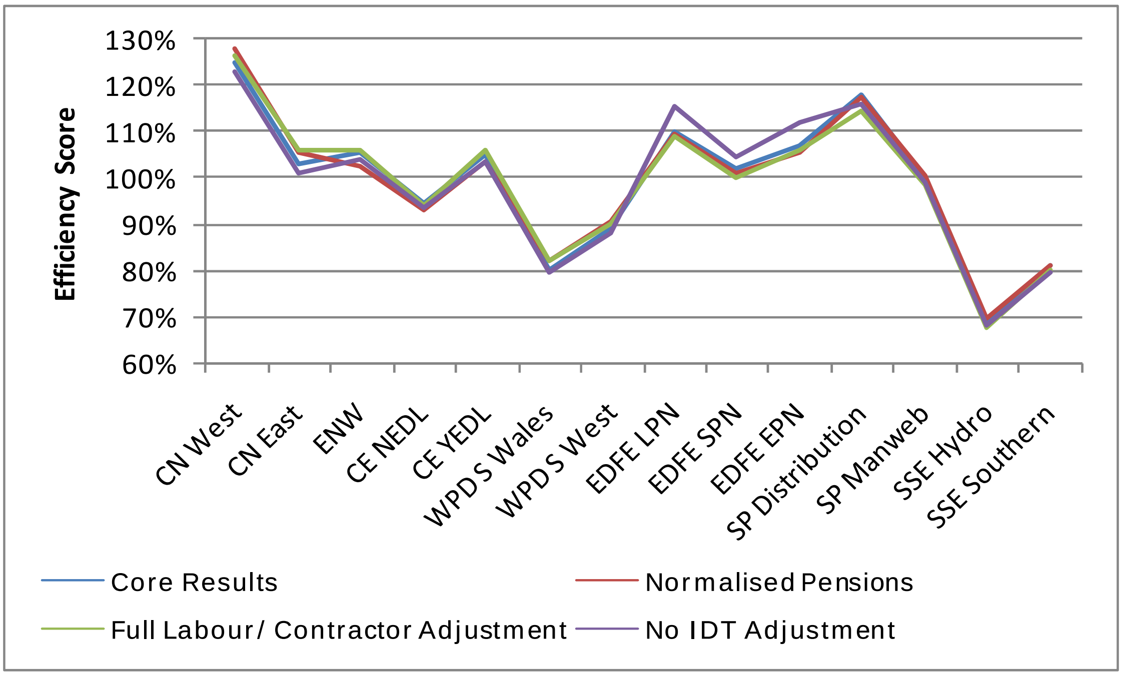
3.44. This section presents an overview of the key issues and results for which we have run alternative scenarios to consider the impact of alternative assumptions. The issues this section address and the alternative scenarios we have run are:

- Pensions - inclusion of a 'normalised' pensions costs.
- Labour and contractor adjustments - inclusion of adjustments for all DNOs.

- Alliance Contracting - exclusion of the adjustment to EDFE costs for their 'IDTs' made in the core benchmarking.

3.45. Figure 3.3 provides a graphic representation of the scores for each of the DNOs under the core and the three alternative adjustments noted above.

Figure 3.3 - Comparison of Efficiency Scores for core linear regression on top-down basis and the three alternatives for adjustments



3.46. The graph shows that the different adjustments we have used as alternatives do not have a major impact on the overall efficiency scores reported for each of the DNOs. The clearest change is for the EDFE DNOs dependent on whether an IDT adjustment is made.

3.47. We would welcome comments on the impact of the different assumptions we have made and the impact of each of the adjustments on the results of our comparative benchmarking and what adjustments we should apply.

Pensions

3.48. We have listened to the cases made by DNOs for how we should treat pensions as part of the DPCR5 review but we have not reached a firm decision on the inclusion of pensions within the comparative benchmarking. There is a strong case for excluding pensions because of the difficulty of extricating pension costs from the output of the benchmarking and the differences in the pension rates payable by the DNOs. However, pension data is not available for contractor costs and thereby it would not be wholly equitable to exclude DNOs' own labour pension costs in isolation. In such a case a DNO with a proportionately larger internal workforce may be advantaged by having pensions removed from labour costs when determining comparative efficiency scores.

3.49. In the alternative scenarios we have included pensions using a normalised contribution rate on a top-down basis to obtain a view as to the likely impact of the different treatment of pensions. The normalised pension's costs have been determined by using a weighted average contribution rate for the DNOs on an annual basis.

3.50. Pensions costs reported in 2007-08 by the DNOs were £62.6m representing 4 per cent of the costs included within the core comparative benchmarking. Table 3.3 presents a comparison of the results of the core analysis and the results when a normalised pensions cost is included.

Table 3.3 - Comparison of Efficiency Scores for Top-Down Linear regressions on a per DNO basis for inclusion of normalised pensions.

DNO	Core Result	Result: Normalised Pension Rate	Difference
CN West	125%	128%	3%
CN East	103%	105%	2%
ENW	105%	102%	-3%
CE NEDL	94%	93%	-2%
CE YEDL	105%	103%	-2%
WPD S Wales	80%	82%	2%
WPD S West	89%	90%	2%
EDFE LPN	110%	109%	-1%
EDFE SPN	102%	101%	-1%
EDFE EPN	107%	105%	-1%
SP Distribution	118%	117%	-0%
SP Manweb	100%	100%	0%
SSE Hydro	68%	69%	1%
SSE Southern	81%	81%	0%

3.51. The inclusion of normalised pension's costs does not appear to have a notable impact on the efficiency scores of the DNOs with the largest movement being for CN West of 3 per cent. The small changes in efficiency scores did not result in any notable changes in the ranking of the businesses.

Regional Labour and Contractor Adjustments

3.52. Our core adjustment for EDFE LPN is based on the ONS data and includes our current view of the activities which are location specific, i.e. those that have to be performed in or near to the DNO area. The adjustment for EDFE LPN for the core comparative benchmarking for this document is £7.2m representing less than 1 per cent of the costs included within the core comparative benchmarking.

Labour

3.53. We recognise there are issues when comparing businesses differences in employing labour and contractors in different parts of the country. At DPCR4 we included a specific adjustment for the London DNO to account for additional costs of employing labour and in the Gas Distribution Price Control Review we made an adjustment for operating within the M25 area.

3.54. We have engaged in extensive discussions with the DNOs and other parties in relation to our proposals for labour and contractor regional adjustments and there is significant disagreement amongst the DNOs.

3.55. EDFE has suggested that Ofgem should use the Annual Survey of Hours and Earnings (ASHE) data provided by the Office for National Statistics (ONS) for a regional labour adjustment because it provides robust independent data on the market salary level differences across Great Britain.

3.56. Other DNOs have highlighted concerns about the robustness of the ONS data for application to the electricity sector. Those concerns include:

- The survey is based on a random sample of staff at an occupational code level that results in a changing representation of earnings each year.
- The survey is only statistically significant at a degree of aggregation of trades such that specialist workers within the electricity distribution industry are only a tiny element and therefore do not influence the overall results.
- There are large unexplained variations in the values reported on an annual basis.

3.57. Other DNOs have also expressed the view that in reality regional cost differences are only evident in the broader London area and that an adjustment should only be made for labour required there. We have discussed this view with the DNOs and there seems to be general agreement amongst them, with the exception of EDFE, that Ofgem should only make an adjustment for work required within the M25 as was done in the Gas Distribution Price Control Review (GDPCR).

3.58. Ofgem have been provided with a copy of a report produced by the Unite Union which included consideration of regional pay. The report suggested that salary banding for 'craftsmen' working on the network were very similar for DNOs across the country. In that survey the top banding figure for pay was shown to be within 6 per cent of the highest rate (for EDFE LPN).

3.59. EDFE have responded to the Unite Union questioning the quality of the data provided in the survey and highlighting that 'craftsmen's and mate's …average salary is…12% higher than the numbers quoted'. EDFE also state they have compared starting salaries and provide an example that for an apprentice the starting salary is £19,100 but less than half that figure for some other DNOs.

3.60. Other DNOs have responded to the Unite Union identifying incorrect data relating to other aspects of the survey results but not on the section relating to regional pay.

Contractors

3.61. EDFE have used the Building Construction Information Service (BCIS) data on regional costs for construction contractors to develop a contractor adjustment. Ofgem used the BCIS data in the Gas Distribution Price Control to adjust contractor costs for Gas Distribution Networks operating within the M25 area.

3.62. Other DNOs have expressed views that there should be no contractor adjustment or only within the M25 area because the market for contractors in national. Anecdotal evidence has been provided suggesting that contractors only adjust tender costs for work around the London area. Those DNOs argue that there is significant volatility in the BCIS data which means that such an approach for contracting is not robust.

3.63. We are still considering the appropriate approach to inform our Initial Proposals baselines. For the base scenario in this document we have only included an adjustment for labour and contractors for EDFE LPN based on ONS data. We have included an alternative scenario to identify the potential impact of a labour adjustment across all DNOs.

Labour/Contractor scenario results

3.64. Table 3.4 presents a comparison of the results of the core analysis and the results when labour and contractor regional adjustments are applied across all of the DNOs to obtain a view as to the likely impact of the different treatment.

Table 3.4 - Comparison of Efficiency Scores for Top-Down Linear regressions on a per DNO basis for inclusion of labour and contractor adjustments for all DNOs

DNO	Core Result	Result: Labour/ Contractor adjustment for all DNOs	Difference
CN West	125%	127%	2%
CN East	103%	106%	3%
ENW	105%	106%	1%
CE NEDL	94%	94%	-0%
CE YEDL	105%	106%	1%
WPD S Wales	80%	82%	2%
WPD S West	89%	90%	1%
EDFE LPN	110%	109%	-1%
EDFE SPN	102%	100%	-2%
EDFE EPN	107%	106%	-0%
SP Distribution	118%	114%	-3%
SP Manweb	100%	99%	-1%
SSE Hydro	68%	67%	-1%
SSE Southern	81%	80%	-1%

3.65. The widening of the labour and contractor adjustments to encompass all reported differences in ONS data does not have a notable impact on the efficiency scores of the DNOs with only CN East and SP Distribution having the highest change in scores of 3 per cent. The change in adjustment did not result in any notable changes in the DNO rankings.

Alliance Contracting Adjustment

3.66. In discussions with the DNOs prior to and since the December document we have considered the problems for comparative analysis brought about due to the different reporting of costs resulting from the procurement strategies of the DNOs. Due in part to the structure of the RRP, but also the different visibility DNOs have of the costs incurred by their contracting parties, DNOs report similar costs within the direct or indirect activities as defined in the RRP.

3.67. Our view is that we should try to ensure that we compare DNOs on an equitable basis and where we identify material differences in reporting we should consider this. We have previously attempted to develop an adjustment purely based on the proportion of direct costs incurred through contractors but have found the development of a robust adjustment very difficult to develop because of the reporting differences.

3.68. In discussions with some of the DNOs we are persuaded that where 'open book' contracting relationships with contractors result in changes in reporting this should be taken into account as part of the comparative benchmarking.

3.69. There is still work required to develop this adjustment. For the purposes of our core analysis in this document we have adjusted costs only where DNOs have identified indirect costs relating to such open book contracts. Typically, the changes result in more indirect costs reported because of the greater visibility of costs under this arrangement. Over the coming months we will discuss this issue with the DNOs to determine how to account for the different level of transparency of contractor costs prior to Initial Proposals. The total adjustment we have made to date for the procurement strategy is £15.2m representing less than 1 per cent of the costs included within the core comparative benchmarking.

3.70. Table 3.5 provides a comparison of the results of the core analysis and the results when no adjustment is made for the visibility of contractor costs.

Table 3.5 - Comparison of Efficiency Scores for Top-Down Linear regressions on a per DNO basis for exclusion of adjustments to EDFE costs for recognition of contractor indirect costs

DNO	Core Result	Result: No IDT Adjustment	Difference
CN West	125%	123%	-2%
CN East	103%	101%	-2%
ENW	105%	104%	-2%
CE NEDL	94%	93%	-1%
CE YEDL	105%	103%	-2%
WPD S Wales	80%	79%	-1%
WPD S West	89%	88%	-1%
EDFE LPN	110%	115%	5%
EDFE SPN	102%	104%	2%
EDFE EPN	107%	112%	5%
SP Distribution	118%	116%	-2%
SP Manweb	100%	99%	-1%
SSE Hydro	68%	68%	-1%
SSE Southern	81%	79%	-1%

3.71. The exclusion of a contractor recognition adjustment results in a worsening of efficiency scores for the EDFE DNOs of between 2 per cent and 5 per cent with relatively consistent improvements for the other DNOs. There are no notable changes in the rankings of the DNOs.

Results - Assessing Activity Group 3 on individual DNO Group basis

3.72. In our discussions with the DNOs we have identified that some indirect costs are organised on a per-DNO Group basis and these costs include the activities of Network Policy, HR, Finance & Regulation and CEO Etc. These activities together make up Group 3 in our analysis.

3.73. As a comparison to the base regressions we combined the results for this group on a per DNO Group basis with the results of the other costs on a per DNO basis. Table 3.6 shows the difference between this combination of techniques to the base regressions on a per DNO basis using both linear and log-log regressions.

Table 3.6 - Comparison of Efficiency Scores for Groups on combined basis using Per DNO Group regressions for Group 3 costs - Linear

	Core Score: Linear: Per DNO	Core Score: Log-Log: Per DNO	Difference: Linear: Group 3 on per DNO Group Basis	Difference: LogLog: Group 3 on per DNO Group Basis
CN West	123%	124%	-1%	0%
CN East	102%	102%	2%	0%
ENW	105%	101%	-5%	-5%
CE NEDL	93%	96%	-0%	-0%
CE YEDL	107%	102%	-0%	-0%
WPD S Wales	75%	83%	-0%	-1%
WPD S West	87%	91%	-0%	-1%
EDFE LPN	100%	100%	2%	2%
EDFE SPN	100%	103%	2%	3%
EDFE EPN	112%	108%	2%	2%
SP Distribution	116%	115%	-0%	-0%
SP Manweb	102%	102%	-0%	-0%
SSE Hydro	66%	74%	-0%	-0%
SSE Southern	90%	83%	-0%	-0%

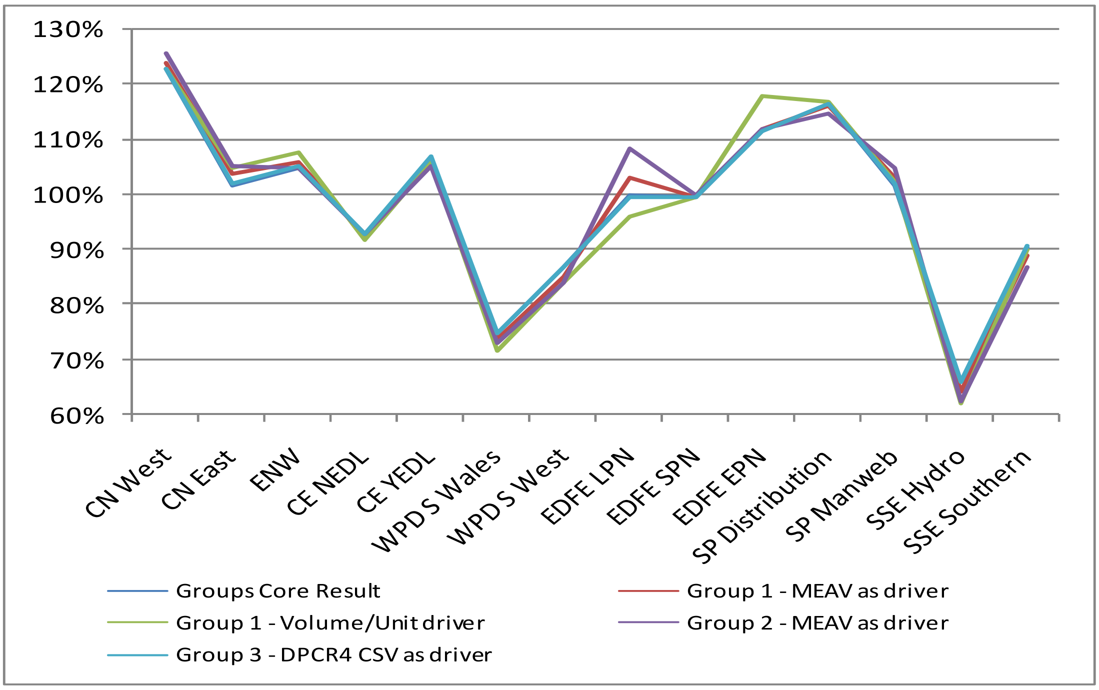
3.74. As expected the combining of per DNO and per DNO Group results improves the position of ENW, as the only singleton, and worsens the position of EDFE compared to the per DNO basic analysis.

Results - Groups alternative cost drivers

3.75. We recognise the differences of view across the industry as to the most appropriate driver to use for our comparative benchmarking and the potential for different results dependent on the choice of driver. We have tested our results using different drivers for the groups of activities to identify the impact on efficiency scores. The alternative drivers we have used have been identified in Table 3.6 above.

3.76. Figure 3.4 provides a chart showing the impact on efficiency scores of the DNOs of using different drivers.

Figure 3.4 - Comparison of linear regression results for 'Groups' using different drivers



3.77. The chart shows that the substitution of different drivers for each of the groups does not appear to make major differences to the overall efficiency scores for the DNOs. Further details of the results and explanation of the alternative drivers we have used are included in appendix 5.

Key Issues - Other Adjustments

3.78. We have adjusted DNO costs where we consider those adjustments are appropriate and where we have been able to develop a methodology for calculating those adjustments. We have discussed these adjustments in the assumptions for the benchmarking section earlier in this chapter. There are other adjustments that DNOs have recommended to us where we are not yet in a position to make a final decision whether to include them. In other cases we have not developed an appropriate adjustment. We will undertake further work in the following months and confirm our view of those adjustments, and include them as appropriate in Initial Proposals. We welcome views on these potential adjustments

3.79. The potential adjustments for consideration are:

- Urbanity
- Interconnected Networks
- Sparsity

Urbanity

3.80. EDFE have provided us with some results of work undertaken by the French Regulator relating to the cost of working in an urban environment. This work suggests that working in urban or 'super-urban' environments incurs notably higher costs than in more rural environments. The additional costs could relate to such factors as cable tunnels, forced ventilation maintenance, overtime etc.

Interconnected Networks

3.81. Scottish Power has provided us with a presentation explaining the higher costs of operating an interconnected network such as that within the SP Manweb area. The additional costs relate mostly to the different number and types of equipment used in an interconnected network.

Sparsity

3.82. Scottish & Southern has presented a report to us that identifies the additional costs of working in extremely sparse areas such as the west of Scotland and the island communities therein. These additional costs include those of maintaining adequate cover over large areas and transporting equipment.

Costs excluded from benchmarking analysis

3.83. We consider comparative benchmarking to be an informative technique to assist us in determining comparative efficiency levels within the DNOs. For some costs, however, the use of such techniques is not appropriate. We have identified three areas of costs that we have taken outside comparative benchmarking listed below. The costs for these three areas are provided in table 3.7.

- Costs transferred to Network Investment
- Costs under consultants' review - IT and Property
- Other Costs

Table 3.7 - Total Operational Costs excluded from the comparative benchmarking work (£m)

	Costs Transferred to Network Investment	Costs under consultants' review	Other Costs	Total
CN West	4	14	11	29
CN East	5	12	10	27
ENW	3	16	6	25
CE NEDL	3	9	6	18
CE YEDL	3	9	8	20
WPD S Wales	2	10	6	18
WPD S West	6	12	8	26
EDFE LPN	2	16	6	24
EDFE SPN	4	14	8	26
EDFE EPN	6	26	14	46
SP Distribution	5	11	6	22
SP Manweb	4	11	5	20
SSE Hydro	5	13	9	27
SSE Southern	10	16	14	40
Total	62	189	117	368

3.84. These costs in total represent around 34 per cent of the costs included in the comparative benchmarking. Further details of the costs included within each of the headings given in the table are included in appendix 5.

3.85. The costs transferred to Network Investment will be included within the modelling for those costs and the consultants' review will use benchmarking and other techniques to determine the efficient level of costs.

3.86. The 'Other Costs' category represents those costs we consider inappropriate for comparative benchmarking and they represent just 11 per cent of those costs included in the benchmarking. We will undertake further analysis of these costs to identify trends and differences between the DNOs' reported costs to inform our baseline view of efficient costs. We welcome comments regarding how we should determine baselines for these costs.

IT and property

3.87. In our December policy document we indicated that we would be seeking expert review of the DNOs' IT and property management costs, both of which are reasonably complex in nature and less suitable for comparative benchmarking. We invited tenders in December 2009 and we appointed Mouchel Management Consulting Ltd and Drivers Jonas LLP (DJ) in January 2009 as IT and Property consultants respectively.

3.88. Appendices 14 and 15 of this document include methodology statements from each of the consultants. No cost or comparative data is being presented at this stage because the review is still work in progress. We expect each of the consultants to present their first draft report to Ofgem at the end of May 2009. We will ensure that the results of those reviews are shared with the DNOs as soon as possible after receipt of the reports and we will include the overall conclusions and baseline cost data in the Initial Proposals document. Once those reports are finalised we will publish them on our website.

IT

3.89. The review of DNOs' IT costs is limited to the non-operational IT activities as defined in the RRP guidelines i.e. excludes IT equipment used exclusively in the real time management of network assets such as RTU units and communication equipment receivers at the control centre. There are three key areas of work in the assessment of DNOs' non-operational IT costs:

- Identifying key functional components such as desktop, server application development, hardware etc. and benchmarking the DNOs against each other and suitable external benchmarks,
- Qualitative review of IT policies and practices judged against industry best practice, covering areas such as procurement, project management, corporate IT strategy, use of contractors, offshore developers, effectiveness of outsourcing etc,
- Qualitative review of the costs and functionality of the IT systems used by the DNOs, particularly in regard to the DNOs' forecasts for replacing the systems in the remaining DPCR4 and DPCR5 periods.

3.90. Mouchel consultants visited each of the seven operating companies early on in the review, following a data collection questionnaire submitted in February. Mouchel held a data validation meeting with the DNOs and Ofgem towards the end of March.

Property

3.91. The review of DNOs' property management costs is limited to non-operational property such as offices and depots. Substations and other operational premises are excluded from the study. There are four elements of the property review:

- Assessment of work space deployment by comparing work metrics with DNOs and external companies. This covers work space allocation, occupancy levels and working practice,
- Analysis of costs of work space to determine whether estate costs are efficient in terms of unit costs, rents etc,

- Review of facilities management (FM) services to assess efficiency internally between DNOs and against external benchmarks,
- Review management of surplus property and assess the scope for rationalisation of surplus property.

3.92. DJ has engaged property benchmarking specialists, IPD Occupiers, to undertake the comparative analysis work utilising a significant database of property costs collected since 1994. Three data templates were issued, covering business/estate strategy, space and property costs and forecast property costs. Drivers Jonas held an initial meeting with Ofgem and DNO property representatives in February. DJ undertook site inspections and DNO visits in February and March, with follow up visits scheduled for April and May.

Atypical Costs

3.93. The DNOs report atypical costs as part of the annual RRP submissions. These costs include certain types of severance and restructuring costs as well as other one-off costs. Over the coming months we will consider those atypical costs and come to a view how to determine baseline efficient values of atypical costs for the DNOs. Table 3.8 sets out the atypical cash costs reported to us by the DNOs as part of the RRP process. These costs exclude atypical severe weather costs because they have been included in the comparative benchmarking work.

Table 3.8: Reported atypical cash cost per DNO for the years 2005-06 to 2007-08 (£m)

DNO	2005-06	2006-07	2007-08	Total
CN West	3.7		1.1	**4.8**
CN East	7.5		0.9	**8.5**
ENW	0.5		11.6	**12.1**
CE NEDL	0.8	0.6		**1.4**
CE YEDL	-0.1	-0.1	4.8	**4.6**
WPD S Wales	0.4		0.4	**0.8**
WPD S West	1.2	0.9	1.2	**3.3**
EDFE LPN	2.4	4.7	2.1	**9.2**
EDFE SPN	1.8	-1.0	2.1	**2.9**
EDFE EPN	5.3	10.1	2.8	**18.2**
SP Distribution				
SP Manweb		0.4		**0.4**
SSE Hydro		-0.2	0.7	**0.5**
SSE Southern		-0.8	1.5	**0.7**
Total	**23.6**	**14.6**	**29.1**	**67.3**

3.94. As the table shows there is considerable variation in the atypical cash costs reported by the DNOs. We will ensure over the coming months that we have a clear understanding of the composition and causes of those costs leading up to Initial

Proposals. We welcome views on how we should treat atypical costs as part of the DPCR5 settlement.

Development of Initial Proposals

3.95. At DPCR4 we introduced the information quality incentive (IQI) to encourage DNOs to submit more realistic forecasts and to allow us to consider those forecasts, along with the analysis carried out by Ofgem and PB Power, in the price control settlement. As discussed later in this chapter we are proposing to extend the IQI to cover network operating costs as well as network investment and any indirect costs closely associated with those areas of work. Under the IQI mechanism, those companies that submit a higher cost forecast relative to the Ofgem baseline will receive a higher cost allowance. However, this will to some degree by offset by a lower amount of additional reward and less powerful shareholder rewards for efficiencies which bring actual costs in below the allowance.

3.96. DNOs will have to provide a detailed explanation and audit trail of areas where their cost forecasts differ from those presented to us in February.

3.97. Our benchmarking results form an important input into our assessment of the DNOs' efficiency and highlight where there are potential issue in the DNO forecasts but are part of a wider set of information that we will use to determine baselines.

3.98. We have already undertaken a wide range of consultation and meetings with the DNOs and other stakeholders which have given us a better understanding of key issues with regards to the cost assessment process and a more thorough picture of the issues relating to particular DNOs' costs. We are considering the extent to which DNOs have undertaken effective customer engagement to inform their business plans and ensure they target investment appropriately targeted.

3.99. We have reviewed the narrative submitted by each DNO to understand the robustness of their forecasting processes and associated assumptions. We have discussed issues arising from this as part of the bilateral cost meetings during March and April.

3.100. We have a good understanding of DNOs' businesses and their historical performance through the RRP process and other price controls. We will consider companies' performance in DPCR4 and how they behaved as part of the previous price control process.

3.101. We will also form a view on how we should use the results of our comparative benchmarking and other techniques for the base years to set baseline operational costs for DPCR5 taking into account the scope for ongoing efficiencies and real input price effects.

4. Methodology – Core network investment

Chapter summary

This chapter gives an overview of the methodologies being used in the assessment of network investment costs. It focuses primarily on the assessment of asset replacement needs and general reinforcement requirements, describing the modelling carried out and the process for updating the initial results with any detailed evidence of investment needs that is provided by the DNOs and other wider evidence.

Question 1: Do you agree with Ofgem's approach to assessing core network investment allowances based on the wide range of evidence detailed in the chapter?
Question 2: Do you agree with the primary network general reinforcement modelling methodology that Ofgem has adopted for DPCR5?
Question 3: Do you agree with the asset replacement modelling methodology that Ofgem has adopted for DPCR5?
Question 4: Is the outlined process for developing Initial Proposals suitable?

Overview

4.1. This section contains an overview of our methodology for assessing the core areas of network investment for DPCR5. We also present the initial results of the first stage of our modelling for general reinforcement and asset replacement. Further details are provided in appendices 6 and 7.

4.2. As discussed in chapter 2 we have divided network investment expenditure into "Core" and "Non-core" expenditure. Core expenditure is less-discretionary, in most cases with higher levels of certainty and is generally not covered by a separate incentive mechanism.

4.3. We have asked the DNOs to submit their FBPQs according to a common template which splits costs into different "building blocks". Definitions of each building block are provided in the glossary. We consider core expenditure to consist of the following building blocks:

- Net demand customer specific expenditure,
- General reinforcement expenditure,
- Fault level expenditure,
- Diversions expenditure,
- Asset replacement expenditure,
- Legal and safety expenditure, and
- Operational IT and telecoms (excluding BT 21st century networks (BT21CN).

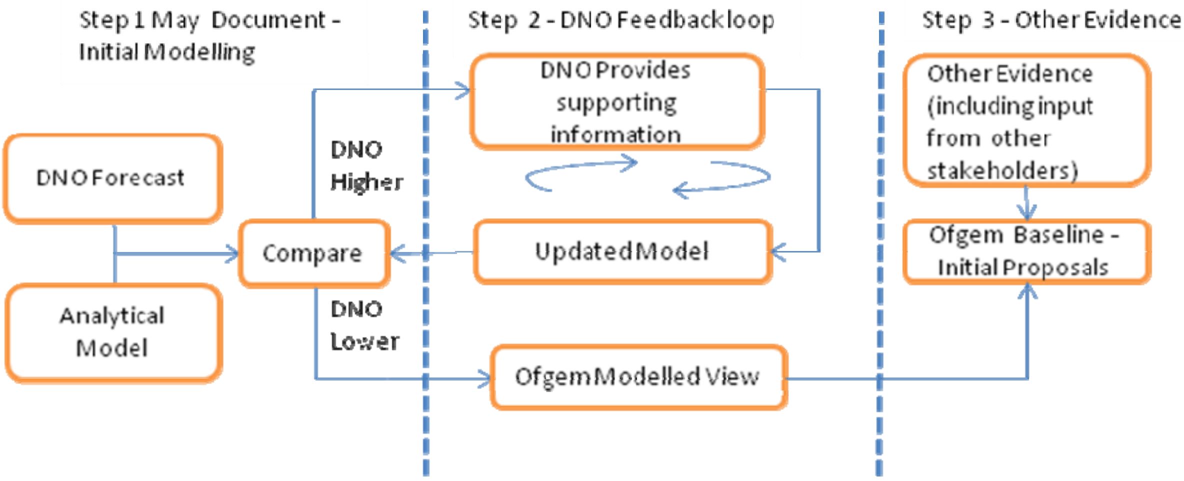
4.4. In total across the industry the core network investment represents 88 per cent of the total forecast levels of network investment excluding real price effects and distribution generation. The following non-core building blocks are discussed in chapter 5:

- Distributed Generation,
- Discretionary expenditure, and
- Losses

4.5. Our approach to HILP is discussed in appendix 13. For other non-core areas of network investment we are currently developing our view for Initial Proposals.

4.6. For DPCR5 we are considering a wide range of evidence when assessing core network investment to form our baseline view. The outputs of our network investment modelling and any supporting evidence provided by the DNOs (such as specific condition information) are key inputs to this assessment. However, we will also be taking account of factors such as past performance, evidence from RRP visits and the quality of supporting output measures. An overview of our approach is shown in figure 4.1.

Figure 4.1 - Overview of methodology



4.7. As shown above, the overall methodology can be split into three key steps:

- Initial modelling,
- DNO feedback, and
- Other evidence.

4.8. Ofgem's baseline will be informed by modelling and analysis but unlike DPCR4 there will not be a hard link between the output of the models and Ofgem's baseline levels of expenditure. The model will provide one source of evidence in a more holistic approach, which will utilise all available evidence to inform the setting of baseline expenditure including the views of other stakeholders.

4.9. Where a DNO is unable to provide robust supporting evidence or their forecast is inconsistent with the other evidence, the modelled output will be the backstop position for setting Ofgem's baseline level of investment.

Initial modelling (step one)

4.10. We are making use of a number of analytical techniques including modelling and benchmarking to form an initial view of each DNO's forecast. Table 4.1 below provides a high level summary of the different approaches we will be applying to each of the core building blocks. The percentage increase in cost for all DNOs from DPCR4 to DPCR5 and the percentage the building block represents of the total forecast for core expenditure are also shown.

Table 4.1 - Analytical approach by building block

Building Block	**Increase DPCR4 to DPCR5**	**Percentage of Core Forecast**	**Analytical approach**
LR1 – Demand	49%	5%	High volume low costs connections - unit cost analysis based on volume driver, benchmarking High Cost Low volume connections - run rate analysis, unit cost analysis, scheme analysis
LR3 - Diversions	28%	5%	Run rate analysis, unit cost analysis, benchmarking
LR4 - General Reinforcement	40%	23%	LV and HV -run rate analysis, unit cost analysis, benchmarking EHV and 132kV - Ofgem general reinforcement
LR6 - Fault levels	197%	2%	Run rate analysis, unit cost analysis, scheme analysis
NL1 - Asset Replacement	33%	55%	Asset Replacement - Ofgem asset replacement model (see detail below) OHL Refurbishment - run rate analysis, unit cost analysis, benchmarking Civils (not modelled) - run rate analysis, unit cost analysis, scheme analysis
NL8 - Operational IT and telecoms	25%	2%	Run rate analysis, unit cost analysis, scheme analysis, expert review (PB Power)
NL9 - Legal and safety	132%	8%	ESQCR - informed by DPCR4 reopener volumes, unit cost benchmarking Other Legal and Safety - run rate analysis, unit cost analysis, scheme analysis, benchmarking

4.11. At this stage we have focused on the general reinforcement and asset replacement building blocks given their higher materiality and the ability to undertake industry-wide benchmarking.

4.12. For the other core building blocks we are currently progressing our analysis although as the overall level of materiality for these areas is much lower than for general reinforcement and asset replacement and differs significantly across DNOs our approach will be tailored to each DNO to allow us to focus on areas where there is a material impact or where the DNO is an outlier compared to the rest of the industry.

4.13. In addition to the individual building blocks we are also reviewing, assisted by PB Power, the unit cost schedules provided by the DNOs as part of the FBPQ. The outcome of this analysis will be used both as an input to the models where appropriate and as part of the wider evidence.

4.14. We are also undertaking a detailed review of a sample of scheme papers associated with very large projects, again assisted by PB Power. For EDFE LPN due to the high costs and complexities associated with central London we are reviewing the overall strategy, focussing on a number of high cost schemes. This will be used both to inform the modelling and to form part of the wider evidence.

DNO feedback (step two)

4.15. Where a DNO's forecast is higher than our initial modelling and/or analysis would indicate, we are asking for additional supporting evidence from the DNO to justify its forecast. The type of evidence required will be building block specific but in general will be bottom up in nature, capturing the key drivers for investment. Examples of the type of evidence that will be required are:

- detailed condition information,
- detailed substation specific levels of utilisation and load growth,
- robust and well developed scheme papers,
- detailed cost benefit information including the benefits to customers,
- quantification of the consequences of reducing or deferring investment including the impact on customers,
- the outputs that will be delivered and the consequences of reducing or deferring investment on the outputs, and
- evidence from stakeholder engagement.

Other evidence (step three)

4.16. In addition to the updated outcome of our model taking account of DNO feedback, we will take account of more general, wider evidence in forming our baseline. This evidence will include:

- quality of DPCR4 forecast (IQI factor),

- DNOs' performance against their own DPCR4 forecasts,
- actual outturn for DPCR4 including expenditure profiles,
- overall views formed as part of the annual RRP process such as quality of scheme papers and the quality of asset management processes,
- comparison of industry wide metrics such as level of network utilisation, asset performance, unit costs, fault rates, CIs and CMLs,
- overall quality of the package of outputs provided, and
- overall quality of stakeholder engagement.

4.17. In addition Ofgem will make use of information provided by other stakeholders such as responses to the consultation documents and other feedback such as that provided at the workshops and other forums.

4.18. Based on all the evidence above, Ofgem will form a robust overall assessment of each of the DNO's requirements for network investment for the baseline proposals.

Key analytical models and initial results

4.19. The key analytical models cover asset replacement (55 per cent of core expenditure) and general reinforcement (23 per cent of core expenditure). An overview of the model and our initial results are discussed below.

General reinforcement model

4.20. The model addresses two key questions:

- are DNOs forecasting an appropriate amount of additional capacity given forecast demand growth? and
- is capacity being added at an appropriate cost?

4.21. At DPCR4 our top-down model benchmarked forecast expenditure relative to overall net growth in units distributed and customer numbers. The model was applied to all load related expenditure (LRE) and also took account of historical levels of expenditure. A number of issues were raised with the previous modelling. These included:

- overall net growth in units is a poor driver of total LRE,
- net customer numbers is a poor driver for total LRE,

- the model did not take account of differential growth rates at individual substations which is not reflected in overall system demand at the net level (churn), and

- for some DNOs, by taking account of historical expenditure, the model predicted a negative future level of expenditure.

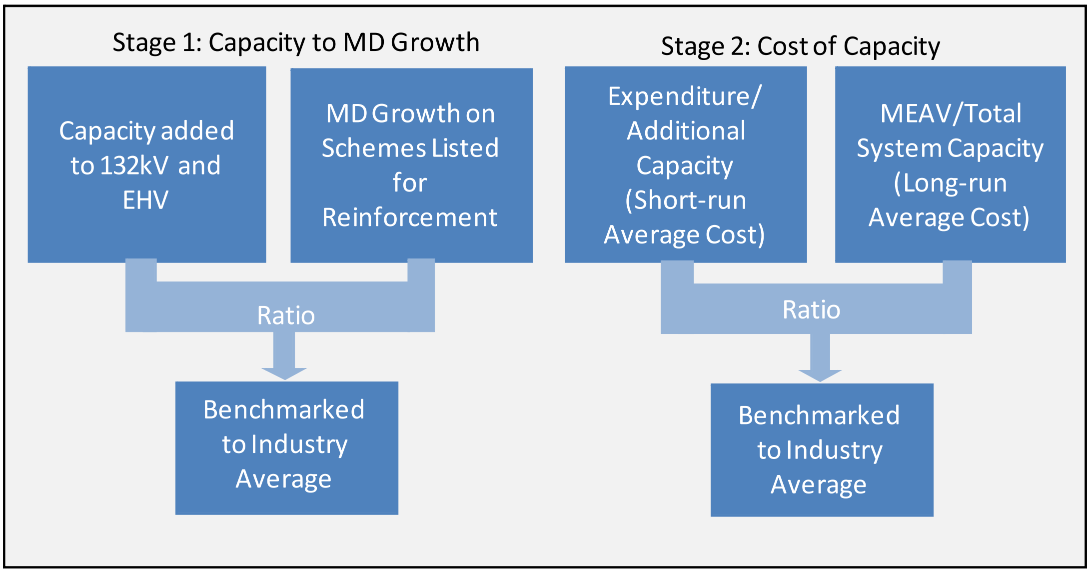
4.22. To address these concerns, we are taking a different approach to LRE investment modelling in DPCR5. We are applying the model to EHV and 132kV general reinforcement only. Demand connections and lower voltage reinforcement are considered separately. This is discussed in appendix 6.

4.23. To address the key questions set out above the model has been developed to benchmark the DNOs' forecasts in two stages (also shown in figure 4.2 below). These are:

- ratio of capacity to be added to forecast demand growth, and

- ratio of DNO's own forecast cost of adding capacity to its long run average cost of adding capacity.

Figure 4.2 - General reinforcement model



4.24. Demand growth is taken as the gross demand increase on substations where reinforcement is forecast. This ensures that only demand which is driving expenditure is included in the model and, unlike net growth in overall system maximum demand, it is not offset by negative growth on other areas of the network where investment is not forecast.

4.25. By using each DNO's own long-run costs in the benchmarking process, we take the DNO's particular network characteristics into account. Due to the very lumpy nature and high costs of N-2 schemes they have been excluded from the model and we will assess them separately.

4.26. EDFE LPN has been excluded from the model due to the high cost and complexities associated with central London. Like the N-2 schemes, the level of investment will be reviewed based on a bottom up analysis of schemes papers.

4.27. This approach provides a robust starting point for discussions on appropriate levels of general reinforcement expenditure in DPCR5. We expect DNOs to provide strong supporting evidence where they are shown to be higher than the industry average for either stage of benchmarking. Further details on the model are provided in appendix 6.

General reinforcement initial results

4.28. Table 4.2 below shows the result of our initial modelling. Companies are banded between very high and very low relative to the industry average for the two stages of benchmarking. Average (+) and Average (-) show DNOs who are in the average band but are marginally under or over the average. Further details of the results are provided in appendix 6.

Table 4.2 - General reinforcement initial modelling results

DNO	Capacity / Growth	£m / MVA Short Run
CN West	Very Low	Very Low
CN East	Low	Low
ENW	Average (+)	Low
CE NEDL	Very High	Average (-)
CE YEDL	High	Low
WPD SWales	High	Very Low
WPD SWest	Very Low	Average (-)
EDFE LPN		
EDFE SPN	Low	Very High
EDFE EPN	Very Low	Very High
SP Distribution	Very Low	Very High
SP Manweb	Very High	Average (+)
SSE Hydro	Average (+)	High
SSE Southern	Low	Average (-)
Average	12	0.51

4.29. The average ratio of capacity to growth for the industry is 12 which implies 12 MVA of firm capacity being added for every 1 MVA of forecast maximum demand growth.

4.30. There are a number of valid reasons why this ratio will be of this magnitude such as:

- capacity being added in large chunks due to standard equipment sizes,
- the five year growth window does not capture historical growth which will also be driving the need for investment, and
- the marginal cost of capacity may be very low making it economic to add a relatively large amount of capacity once the decision to reinforce is made.

4.31. We are asking all DNOs to provide further justification for the capacity they are proposing to add during DPCR5 given their forecast levels of growth. We will also be reviewing the underlying growth forecasts both for individual substations that are requiring reinforcement and for total system maximum demand to provide an overall sense check.

4.32. The average ratio of the forecast cost per MVA of capacity added to the long run average cost is more in line with what would be expected and on average is around 0.5 (i.e the short run cost of adding capacity is around 50 per cent of the long run cost). DNOs with a ratio higher than average have been asked to provide further supporting information on their forecast regarding the unit cost of adding network capacity.

Asset replacement model

4.33. We have developed a model to address the key question:

- are volumes of replacement being forecast by each DNO consistent with what has been done in the past or with what industry as a whole is planning to do in future?

4.34. We are using a standard age based asset survivor model. This model can be used to forecast a volume of asset replacement for each DNO. This model has been used extensively by Ofgem and its consultants at a number of previous price controls. Most DNOs also use an equivalent model as a sense check for their condition based forecasts to produce forecasts where there is a lack of specific condition information and as a long term forecasting tool.

4.35. The model requires only two inputs:

- the age profile of assets currently installed on the network,
- a replacement profile that reflects the probability of an asset requiring replacement as a function of age (usually in the form of a standard distribution defined by an average expected life).

4.36. For DPCR5 we have further developed the model to calculate asset replacement profiles (simplistically the average expected asset lives) for each DNO based on the actual volumes of condition driven replacement undertaken during DPCR4. We have applied the same process to the DNOs' forecast volumes for DPCR5 to calculate forecast implied lives.

4.37. We have also applied this process to the total volume replaced across all DNOs (both actual and forecast). This represents the weighted average replacement profiles and therefore expected lives that the industry is currently achieving and is forecasting to achieve in DPCR5.

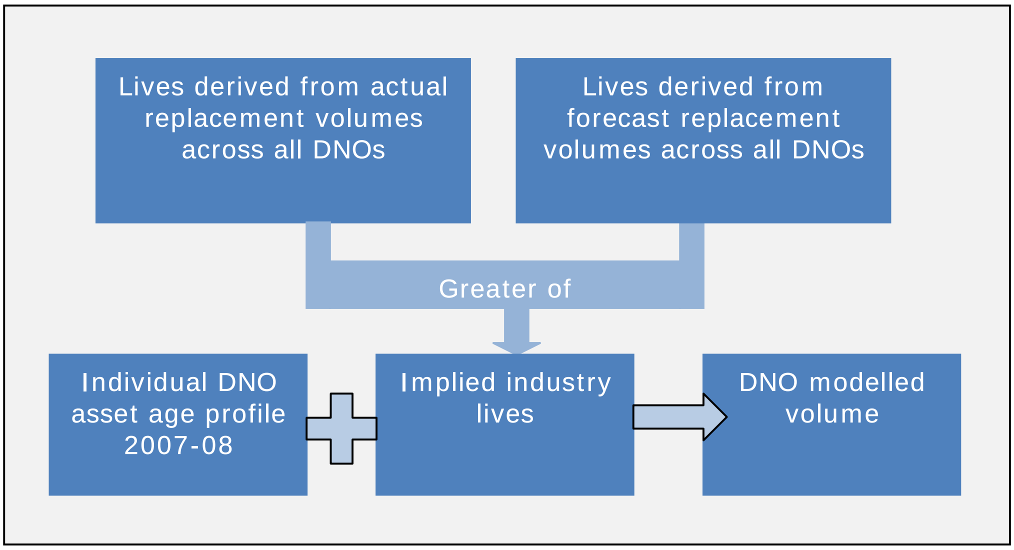
4.38. It has been assumed that across the industry the average replacement profile can either be maintained at the levels achieved in DPCR4 or improved through better asset management (which is reflected in the forecast replacement profile). We have therefore taken the higher of the weighted industry average lives achieved in DPCR4 and those implied by the DNOs' forecasts for DPCR5 in the initial modelling. This is discussed in appendix 7.

4.39. We will be seeking explanation by way of further condition based evidence from the DNO where its forecast implied lives are either:

- shorter than those implied by their own actual replacement volumes, or
- shorter than those implied by the industry average model.

4.40. Using the implied industry lives we are able to run the model with each DNO's individual age profile to obtain an initial modelled view of volumes. This is shown in figure 4.3 below.

Figure 4.3 - Age based model using industry lives



4.41. This approach provides a robust starting point for discussions on appropriate levels of asset replacement in DPCR5.

Asset replacement initial results

4.42. We have set out below an aggregated summary of DNO forecast volumes relative to the model using the industry weighted average lives. In total we have carried out modelling for 68 sub categories of assets. In order to simplify the presentation of the results they have been aggregated into five main asset types:

- overhead line (OHL) conductor,
- OHL supports,
- underground cables (including submarine cables),
- switchgear, and
- transformers,

and two voltage categories:

- distribution assets (LV and HV), and
- primary assets (EHV and 132 kV).

4.43. For each of the main asset types and voltages the DNOs' forecast volumes have been banded between very high and very low relative to the model.

Table 4.3 - Asset replacement initial modelling results[12]

DNO	OHL - Conductor	OHL - Supports	Underground Cables	Switchgear	Transformers
CN West	High/Very high	Low/Very high	Very high	High/Low	High/Low
CN East	Very high	Low/Very high	Very high	High	Very high/Low
ENW	Very low/Low	Very high	Low/High	Low/High	Low/High
CE NEDL	/ery low/Very hig	verage/Very hig	verage/Very hig	High/Average	Very high
CE YEDL	Low/High	Low	Very high	Low/Very high	Very high/High
WPD SWales	Very high/High	Very high	Very high	High/Very high	Very high/High
WPD SWest	Very high/Low	Very high	Very high	Average/Low	Very high/High
EDFE LPN			Very low	Low	Low/Very low
EDFE SPN	Very low/Low	Low/Very low	Very low/High	Average/High	Very low/Low
EDFE EPN	Very low/Average	verage/Very lo	Very low	Very high/High	Very low/Low
SP Distribution	Very low/Low	Very low/Low	verage/Very hig	Average	ery low/Very hig
SP Manweb	High/Very high	High	Very high	Average/Low	Low/Very high
SSE Hydro			Low/Very high	Low/Very high	Very high/High
SSE Southern			Very high/Low	Low/High	Low/High

4.44. For example, where a DNO's volume is shown as "average/high" the DNO's volume is average for distribution assets and high for primary assets. Where a single result is shown, for example "high", the DNO is high at both voltage levels.

4.45. The results above show the net position, with offsetting between assets with higher volumes and those with lower volumes both within each asset category and across the aggregated voltage groups. Because the results have been presented in this way, there may be subsets of assets where a DNO is forecasting higher than the model output even though, for the category as a whole, the forecast volumes are lower than the model. More detail is provided in appendix 7.

4.46. Although there is a large range, all DNOs except EDFE LPN appear to be forecasting high volumes in at least one asset category, with a number of DNOs being consistently high across the majority of asset categories.

4.47. In order to show the approximate materiality of the results, Table 4.4 shows the net position of each DNO across the five asset types in £million relative to the model. Ofgem's draft unit costs have been used to translate both the DNO forecast volumes and the model output into £million of expenditure. As there is considerable work to be done before the unit costs are finalised the results are only indicative to

[12] Note EDFE LPN does not have a material amount of OHL. SSE have indicated as a result of their OHL refurbishment strategy, which has been in place for some time, it has not been practical to maintain their age profile information to a suitable level of accuracy for age based modelling. SSE has therefore been excluded from the model pending further review.

illustrate materiality of the volume difference between Ofgem's model and the DNOs forecast volumes across asset categories and between DNOs.

4.48. In this presentation we have netted off all positive and negative differences to the model within each asset category at all voltages. This is a less onerous presentation of the model results but provides a simple overview of the high level position. Red and positive is higher than the model; green and negative is lower than the model.

Table 4.4 - Relative materiality of initial modelling results

DNO	OHL - Conductor	OHL - Supports	Underground Cables	Switchgear	Transformers
CN West	18	-5	44	6	-9
CN East	25	7	45	25	-13
ENW	-13	46	-10	-15	7
CE NEDL	-8	2	25	18	16
CE YEDL	-1	-9	46	-7	18
WPD SWales	14	20	14	11	22
WPD SWest	19	42	44	-8	33
EDFE LPN			-97	-15	-32
EDFE SPN	-7	-20	-55	19	-24
EDFE EPN	-6	-17	-107	53	-48
SP Distribution	-16	-41	6	-1	9
SP Manweb	2	6	51	-6	22
SSE Hydro			9	-2	11
SSE Southern			4	-16	8

4.49. There is a very large range in total net difference between the model and the DNO forecast ranging from £129million higher than the model to £143 million lower than the model. The gross positive difference, i.e. only taking into account areas where the DNO volumes are higher than the model ranges from £137million higher than the model to £0million lower than the model.[13]

4.50. The initial results have been shared with the DNOs. They have been asked to provide further supporting evidence where their volume is higher than the model. At this stage this has been done at the individual asset level. The DNOs will need to make the case where they believe that volumes in one asset category should be offset by results for other categories.

[13] When summing only the positive differences the lower difference is limited to zero.

Development of Initial Proposals

4.51. Our process for developing Initial Proposals is in line with our three stage process discussed earlier in the chapter.

Asset replacement and general reinforcement

4.52. We are currently in the process of sharing the initial results of our models with the DNOs. In areas where a DNO's forecast is higher than predicted by the model they have been asked to provide additional supporting information. We have already received some of this information.

4.53. For Initial Proposals we will update our modelled volumes to take account of any additional DNO evidence which we consider to be robust. Where DNOs are unable to provide robust evidence we will not update our modelled volumes.

4.54. At Initial Proposals we will also present our initial view on asset unit costs which, when combined with our updated modelled volumes will provide our initial view of condition based network investment requirements.

Other areas of core costs

4.55. The process being applied for the assessment of other areas of core costs is similar to the process used for assessment of asset replacement and general reinforcement. The models being used are generally more simplistic given the lower levels of forecast expenditure. The DNOs will be given the opportunity to provide additional information where their forecasts are higher than indicated by our model.

Overall network investment baseline

4.56. Once we have taken account of the modelling and additional evidence provided by the DNOs for the individual building blocks we will pull this together to make an assessment of the total level of network investment and consider whether this level is consistent with the wider evidence across all DNOs.

5. Network Investment - Environment

Chapter summary

This chapter covers the methodologies we are using to analyse the submitted Forecast Business Plan Questionnaires (FBPQs) to inform the treatment of incentives and expenditures within the proposed environmental policies. This chapter does not provide any policy conclusions, nor does it cover any environmental policy areas not directly linked to the FBPQ submissions.

Question 1: Do you agree with our approach to assessing the forecasts of distributed generation, discretionary expenditure and losses and are there any other factors you think we need to take into consideration?

Distributed generation

5.1. In DPCR4, the distributed generation (DG) incentive was set at £1.50/kW/yr based on an estimated £50/kW average cost of non-sole use connection assets related to DG. This cost was calculated from identified and forecast DG projects (over 10GW) for the DPCR4 period.

5.2. In practice during DPCR4 the average cost of network assets associated with DG has been considerably lower than the DPCR4 forecast, largely because the overall number of DG projects was significantly less than forecast and the majority of DG that did connect did not require network reinforcement.

5.3. According to the February FBPQs, DNOs forecast that 9GW of DG will connect over the DPCR5 period, with an average network asset connection cost of £11/kW. This represents an increase of over 100 per cent from the DG capacity that has connected and is forecast to connect in DPCR4. The breakdown by DNO is shown in table 5.1.

Table 5.1 - Comparison of average use of system network reinforcement cost by DNO between DPCR4 and February FBPQ.

	DPCR5 from February 2009 FBPQ			DPCR4 (actual + forecast) from February 2009 FBPQ	
DNO	Network reinforcement capex	DG capacity connecting in DPCR5	Unit cost of network reinforcement	Network reinforcement capex	DG capacity connecting in DPCR4
	£m	MW	£/kW	£m	MW
CN West	12.8	964	13.29	0.3	323
CN East	23.1	1,584	14.60	2.7	188
ENW	7.2	1,029	7.03	0.5	515
CE NEDL	15.5	442	34.92	0.1	135
CE YEDL	12.9	548	23.50	0.3	227
WPD S Wales	2.1	888	2.36	0.2	197
WPD S West	1.4	291	4.81	0.2	45
EDFE LPN	-	258	-	0.3	2
EDFE SPN	-	449	-	5.1	7
EDFE EPN	4.7	887	5.32	-	163
SP Distribution	7.1	629	11.36	7.2	882
SP Manweb	3.7	125	29.84	14.6	1,015
SSE Hydro	12.4	919	13.49	4.9	513
SSE Southern	0.6	156	3.86	-	79
Total	103.6	9,169		36.4	4,290
Unit cost of network reinforcement (£/kW)	11.30			4.69	

5.4. We are analysing the DNO forecasts by looking at the unit connection cost by generation type. Where there are outliers against the average level, we are seeking further information from the DNOs concerned. We are also comparing DPCR5 forecasts against the cost per unit connected in DPCR4, and following up with the DNOs where there are anomalies.

5.5. There is significant uncertainty around the forecasts for both the volume of DG capacity connecting and the cost of this connection, with DNOs estimating ranges around their forecasts as large as -100 per cent to +290 per cent for capacity and -100 per cent to 165 per cent for cost. This is driven by uncertainty around planned government policy (for example on zero carbon homes), the strength of incentives (such as the level of the feed-in-tariff) for renewable generation, around the speed and scale of the response to such policies and finally, around the access to and cost of finance available to DG developers. In addition, the low volume of DG connected to date and the dependency of connection cost on local network circumstances means the DNOs do not have much experience or confidence in estimating the cost of network reinforcement in the future.

5.6. Table 5.2 highlights that the mix of generation will have a significant impact on total network reinforcement cost. It is unclear how different types of generators may respond to new incentives, and this further exacerbates the uncertainty around the unit cost of connection.

Table 5.2 – Forecast average use of system network reinforcement cost by generation type across DNOs for DPCR5

Types of generation	Unit cost of network reinforcement £/kW
Onshore wind	16.47
Offshore wind	5.21
Tidal stream & wave power	15.82
Biomass & energy crops (not combined heat and power, CHP)	7.34
Hydro	24.21
Landfill gas, sewage gas, biogas (not CHP)	11.52
Waste incineration (not CHP)	9.30
Photovoltaic	0.47
Micro CHP (domestic)	4.52
Mini CHP (<1MW)	6.92
Small CHP (>=1MW, <5MW)	6.43
Medium CHP (>=5MW, <50MW)	4.53
Large CHP (>=50MW)	0.43
Other generation	0.82

Discretionary expenditure for future network flexibility

5.7. In the December Policy Paper[14] we proposed an innovation incentive mechanism to encourage the DNOs to anticipate how future changes in energy policy will impact their networks, be engaged in the debate and be proactive in developing and investing in their networks in order to reduce the risk of the DNOs becoming barriers to the achievement of a low carbon economy. One of the options was for Ofgem to allow ex-ante project funding where DNOs proposed more flexible alternatives to current expenditure proposals or additional projects in the discretionary expenditures table of the FBPQ. Ofgem would assess these proposals and, where justified, allow the additional expenditure in the next price control period.

5.8. To this end we provided instructions for the completion of the DNO discretionary table in the February FBPQ to request details of alternative expenditure to that included elsewhere which would enable the network to be more flexible in the future (with respect to connecting distributed generation, using demand side management or active network management etc.).

5.9. Table 5.3 summarises the DNOs' proposed discretionary schemes.

[14] Electricity Distribution Price Control Review Policy Paper (159/08)

Table 5.3 - Summary of February FBPQ DNO discretionary expenditure for DPCR5

DNO	Total discretionary cost (£m)	Description
CN West	5.1	DG telemetry (SCADA capability) to understand generation and export profiles of larger DG and allow balancing of supply and demand; and implementation of select R&D projects
CN East	8.9	Network "hub" to facilitate prompt and efficient connection of wind generation
ENW	0.8	Strategic acquisition of land suitable for primary substation development within space constrained city centre to enable future customer connections in appropriate timescales
CE NEDL	-	
CE YEDL	-	
WPD S Wales	23.8	Install smart metering at secondary substations to gather consumption data that will facilitate improved analysis of losses, enabling the identification of routes to their reduction
WPD S West	30.7	
EDFE LPN	5.0	Further development and field-trialling of SmartGrid/Active Network Management pilot projects; discrete elements that could be selectively (or reactively) overlaid onto the existing distribution network within the DPCR5 timeframe
EDFE SPN	11.0	
EDFE EPN	14.0	
SP Distribution	0.6	Application of dynamic ratings algorithms to the SCADA host system to improve capacity utilisation; link existing GIS platform to a design (loadflow and fault level) package to allow accurate modelling of the distribution network, to improve network desig
SP Manweb	1.5	Aura- NMS deployment for replacement of legacy operational intertripping schemes in DG constrained area
SSE Hydro	-	
SSE Southern	-	
Total	101.4	

5.10. We note the broad range of scope and cost between the different DNO proposals, accompanied with differing levels of justification. We were disappointed that the DNOs did not use this table to justify some of the areas that they have indicated they cannot afford under the DPCR4 settlement and which is limiting their ability to help tackle climate change. For example, DNOs have mentioned they need, but cannot currently afford to spend money on, specialist staff to manage commercial arrangements for DG and the deployment of initiatives designed under the innovation funding incentive (IFI). However, we do recognise that the timing of the DNOs completing the FBPQ at the same time as the December Policy Paper consulted on the option of having an ex-ante innovation funding mechanism may have made it difficult for DNOs to include fully justified proposals.

5.11. We are assessing each proposal individually on its merits, and will be discussing the justifications in detail with the relevant DNOs. In the assessment we will consider whether the expenditures are adequately justified and also whether this is the most effective funding mechanism (for example, versus the IFI).

Losses

5.12. In the December Policy Paper we recognised that there were benefits associated with the DNO proposed hybrid losses incentive system. We stated that we were considering allowing the DNOs to include low loss equipment expenditure in their DPCR5 forecasts where the expected loss reduction justified the additional expenditure. Our stated intention was to retain an output incentive, but adjust the target for each DNO to take 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.

5.13. In the February FBPQ we included a table to collect information on the costs of schemes specifically aimed at reducing losses and the anticipated resultant loss reductions. We also requested information on the total loss reduction that DNOs forecast would be achieved through the “base case” expenditure (for example through replacing old transformers or adding additional capacity on the network) included elsewhere in the FBPQ.

5.14. Only four DNO groups provided details of proposed low loss investments. A summary of the submissions and our analysis is included below in table 5.4.

Table 5.4 - Summary of DNO proposals for loss reduction schemes over and above base case investments for DPCR5.

DNO	**Total cost of schemes**	**Annual loss reduction**	**Scheme unit cost**	**Payback**
	£m	MWh	£/MWh	years
CN West	2.1	13,488	159	2
CN East	2.0	12,660	155	2
ENW	1.8	3,982	452	5
CE NEDL				
CE YEDL				
WPD S Wales	8.5	6,651	1,279	15
WPD S West	11.8	9,172	1,283	15
EDFE LPN				
EDFE SPN				
EDFE EPN				
SP Distribution	5.2	5,330	967	11
SP Manweb	4.4	5,580	787	9
SSE Hydro				
SSE Southern				
Total	54.3	56,863		

5.15. We requested that DNOs justify their loss reduction proposals based on a nominal loss incentive value (calculated using the forward wholesale electricity price less the EU Emission Trading Scheme (ETS) carbon price, plus the shadow price of carbon, which was the methodology proposed in the December Policy Paper). Our initial analysis of the proposals based on the nominal loss incentive value indicates a wide range of payback periods from two to 15 years.

5.16. We will analyse the individual justifications of these proposals with the costs and forecast loss reductions. We will also benchmark between the DNOs. We note that the DNOs forecasting loss reductions resulting from their "base case" investments have not proposed any additional low loss expenditures. We will analyse this further and compare the DNOs' "base case" investment strategies.

5.17. There are markedly different forecasts of changes in losses resulting from the DNOs' "base case" investments. Some DNOs are forecasting significant loss reductions whilst others are forecasting significant increases. A summary of the forecast base case loss impacts is included in table 5.5. To provide context we have calculated the forecast loss changes as a percentage of each DNO's 2007-08 level of losses, and as a percentage of the units distributed through each network in 2007-08. SP Energy Networks stated that they were unable to provide forecasts due to data unavailability.

Table 5.5 - Summary of DNO forecasts of the impact on losses resulting from "base case" expenditure over DPCR5.

DNO	Change in losses over DPCR5	Equivalent percentage of current losses	Equivalent percentage of current units distributed
	MWh	%	%
CN West	36,234	3.0%	0.12%
CN East	53,184	4.4%	0.20%
ENW	5,904	0.5%	0.02%
CE NEDL	- 23,581	-2.6%	-0.14%
CE YEDL	- 43,360	-3.1%	-0.18%
WPD S Wales	31,777	4.7%	0.25%
WPD S West	47,096	4.6%	0.31%
EDFE LPN	- 7,484	-0.4%	-0.03%
EDFE SPN	- 12,712	-0.9%	-0.06%
EDFE EPN	- 15,354	-1.1%	-0.04%
SP Distribution			
SP Manweb			
SSE Hydro	- 4,999	-0.7%	-0.06%
SSE Southern	- 33,767	-1.5%	-0.10%
Total	32,938		0.01%

5.18. We are analysing the explanations of these forecasts and comparing them between DNOs, and will request further explanation from the DNOs as appropriate.

6. Ongoing efficiencies and input prices

Chapter Summary

This chapter considers our approach to setting assumptions for ongoing efficiencies, and a review of evidence on input prices.

Question 1: Have we identified the most relevant unit cost and productivity measures from other sectors to help inform our ongoing efficiency assumption for DPCR5?
Question 2: When calculating these measures, which comparator sectors and time periods should we focus on?
Question 3: What weight should we give to this analysis relative to other information?
Question 4: What method should we use for setting our input price assumptions for DPCR5?

Ongoing efficiency improvements

Overview

Background

6.1. The allowances that Ofgem will set as part of DPCR5 for network operating costs, business support and other indirect activities will include assumptions for productivity/efficiency improvements and for changes in input prices. The assumption for the trend in industry-wide productivity/efficiency improvements will reflect both expected catch-up by the relatively high-cost DNOs and ongoing efficiency improvements that would be expected to be made by the industry as a whole. These ongoing efficiency improvements are sometimes known as "frontier shift" as they are the improvements expected by the relatively low cost DNOs that do not have any expected catch-up to undertake.

6.2. This section presents preliminary analysis that could be used in conjunction with analysis of expected catch-up to inform our assumptions for the rate of ongoing efficiency improvements to be included within price limits.

Outline of our proposed approach

6.3. A natural starting point for assessing the expected trend in operating expenditure of DNOs is to examine the historical trend in that expenditure. There are problems with such an analysis:

- The trend in expenditure is likely to have been impacted by a privatisation effect which cannot be replicated for the DPCR5 period.

- A consistent time series dataset is not available as the definitions of costs have changed over time.
- The remaining three years of consistent data from the RRP is only a sample that may have been heavily affected by any shocks or anomalies in these years (such as input price fluctuations) that may not be relevant to the next price control period.

6.4. To overcome this issue, we plan to build upon the approach developed at GDPCR where we combined a labour productivity trend from comparator sectors with an input price trend in order to give a unit cost trend relative to the RPI. In addition to this measure of labour productivity, we plan to examine wider productivity and unit cost measures reflecting all of the inputs that comprise operating expenditure i.e. not just labour.

Preliminary analysis of productivity and unit cost trends in other sectors

Overview of the approach

6.5. The basic idea behind looking at other sectors is that the productivity and unit cost trends seen by sectors similar to electricity distribution are indicative of the trends that might be expected for DNOs in DPCR5. We set out below the types of measures that we propose to examine.

6.6. One of the concepts we will examine is productivity growth in comparator sectors. Productivity growth measures the difference between output volume growth and input volume growth. For example, labour productivity growth of 1 per cent a year would imply that the volume of output can be kept constant whilst reducing the volume of labour input by 1 per cent a year.

6.7. Productivity measures can be combined with input price trends to give unit cost trends. For example, a wage trend of 2 per cent a year relative to the RPI when combined with the labour productivity trend of 1 per cent a year would give a unit labour cost trend of 1 per cent a year relative to the RPI. The input price trends used can be those relating to the sector for which the productivity trend was calculated or a trend specific to the operating activities of DNOs.

6.8. When examining productivity or unit cost trends from other sectors it is important to note that the trends observed may have been affected by capital substitution. For example, the labour productivity growth seen in other sectors may only have been possible by substitution from labour to capital inputs. It would be inappropriate to assume that DNOs could match the productivity or unit cost trends seen by other industries that have undergone such capital substitution. For this reason, and in line with the approach adopted by our consultants (Reckon LLP) at GDPCR, we propose to calculate all productivity and unit cost trends with the assumption of constant capital input. The difference between the raw productivity trend and the productivity trend assuming constant capital can be thought of as a capital substitution adjustment. This adjustment will be greatest for those sectors that have experienced the most capital substitution.

Relevant productivity and unit cost measures

6.9. The dataset we propose to use for calculating productivity and unit cost measures from other UK sectors is the EU KLEMS dataset published in March 2008. The dataset has been produced by a European Commission funded consortium that includes the National Institute of Economic and Social Research (NIESR). This dataset draws on national accounts to provide data on inputs and outputs in sectors across the UK economy for the period 1970 to 2005.

6.10. The EU KLEMS dataset presents data on two different types of industry output that can be used to estimate productivity and unit cost trends:

- Gross output: This measures the value of the output in an industry i.e. the combined turnover of the companies in that industry. Changes in the volume of gross output for an industry are calculated by examining changes in constant prices. The inputs for gross output are capital, labour, energy, materials and services.

- Value added: This is the value of gross output minus the value of intermediate inputs (energy, materials and services). The inputs for value added are therefore just labour and capital. Growth in the volume of value added is the change in value added at constant prices.

6.11. Given our interest in examining operating expenditure trends, the most relevant measures to look at depend on the choice of output measure.

6.12. For gross output the most relevant unit cost and productivity measures relate to the labour, energy and materials inputs - the inputs that comprise operating expenditure. Productivity growth for these inputs would measure how quickly expenditure on these operating items could be reduced assuming constant prices while keeping output constant. A trend for real unit operating expenditure could be obtained by combining this productivity measure with a real price trend for the inputs.

6.13. For value added the most relevant measures relate to the labour input only and therefore direct inferences can only be made about labour costs. In order to make wider inferences about operating expenditure the labour productivity or unit labour cost measures must be combined with assumptions about the upstream supply-chain and/or the trends for non-labour inputs. In GDPCR, where we relied on trends in labour productivity calculated on a value added basis, we made assumptions about the trends in the intermediate inputs of the GDNs i.e. the activities upstream in the supply chain.

6.14. The analysis presented above might strongly suggest using measures calculated on a gross output basis. However, there are the following concerns about using a gross output measure of productivity or unit costs:

- Since labour is more substitutable between sectors, labour productivity and unit labour costs might be more comparable across sectors.
- Gross output data might be influenced by industry restructurings in a way that value added data are not.

6.15. At this stage we are examining both value added and gross output measures of productivity and unit costs and we will review our options when formulating Initial Proposals.

Initial results

6.16. This section presents our initial results from analysis of the EU KLEMS database. We will be reviewing these calculations before we formulate our Initial Proposals.

6.17. We have decided to present the unit cost and productivity trends over the entire span of the EU KLEMS dataset - 1970 to 2005. This reflects the belief that there is a constant long-term trend for each sector and that estimating the average over the longest time period available provides the best estimate of these long-term trends. We will review the sensitivity of the results to the choice of time period before Initial Proposals.

The table below presents preliminary results for a selection of sectors. We have included:

- The five sectors presented at GDPCR:
  - construction;
  - financial intermediation;
  - manufacture of chemicals, chemical products and man-made fibres;
  - sale, maintenance and repair of motor vehicles and motorcycles; retail sale of automotive fuel; and
  - transport and storage.
- Additional sectors that appear to be relevant:
  - manufacture of electrical and optical equipment; and
  - manufacture of transport equipment.

Table 6.1 - Productivity and unit cost growth measures adjusted for constant capital (1970-2005)

Comparator sector	Gross output measures		Value added measures	
	Labour and intermediate inputs productivity growth	Unit labour and intermediate inputs costs (relative to the RPI)	Labour productivity growth	Unit labour costs (relative to the RPI)
Construction	0.3%	1.3%	0.8%	1.6%
Financial intermediation	(0.5%)	1.3%	(1.1%)	2.5%
Manufacture of chemicals, chemical products and man-made fibres	1.4%	(1.5%)	5.6%	(2.6%)
Sale, maintenance and repair of motor vehicles and motorcycles; retail sale of fuel	0.7%	0.6%	1.5%	1.1%
Transport and storage	1.2%	(0.5%)	2.6%	(0.3%)
Manufacture of electrical and optical equipment	1.6%	(2.0%)	5.0%	(2.7%)
Manufacture of transport equipment	1.0%	(0.6%)	3.2%	(1.7%)

6.18. We will review the choice of comparator industries used to form our assessment at Initial Proposals. Appendix 9 provides results for all sectors in the EU KLEMS database and provides a description of the methods used to calculate the measures discussed above.

6.19. We welcome views on the most appropriate sectors, measures, and time periods to examine when formulating our Initial Proposals.

Assumptions made by DNOs as part of the FBPQs

6.20. Some DNOs have submitted their assumptions for efficiency improvements over the DPCR5 period as part of their FBPQ submissions in February. These assumptions were discussed in the accompanying commentaries and can be summarised as follows:

- CN assume that operating costs will decrease by 13 per cent (excluding real price effects) over DPCR4 levels due to efficiency improvements. This is equivalent to annual efficiency improvements of around 2.7 per cent.

- SSE include a 0.5 per cent a year ongoing efficiency assumption for all business costs and for network operating costs related to inspections and maintenance, and fault costs.
- WPD assume 1 per cent a year efficiency improvements based on a report prepared by First Economics.

6.21. We will review this evidence and any further information submitted in the final FBPQ submissions in June. When reviewing this evidence we will take account of the source of the evidence. For example, efficiency improvements identified on a bottom-up basis will not include efficiency improvements that might occur but have not yet been identified. We will also take into account the placement of the DNOs in our relative efficiency analysis to ensure that we do not assume an unrealistic rate of ongoing efficiencies for the frontier companies.

Review of evidence on real price effects

6.22. It is important to note that the evidence presented in this section is a series of snapshots that represent the views of certain parties at the time of writing. Given the pace of economic developments, some economic forecasts have changed significantly in only a few months and current forecasts may be subject to similar changes in the coming months. Between now and Final Proposals new evidence will emerge from a range of sources including:

- The final FBPQ submissions made by DNOs in June. It is important that DNOs provide robust evidence for any RPEs that they are building into their forecasts.
- Developments in the wider economy. As more macroeconomic data becomes available it might become easier for us to gauge the impact of the recession and its implications for DPCR5.

6.23. We will review this new evidence as it emerges and will decide on the appropriate assumptions for price limits in light of the best information available at the time.

Evidence submitted in support of the FBPQs

6.24. Ofgem has received studies supporting some of the DNOs' assumptions for real price effects in the FBPQs. The following studies were received:

- First Economics – “The Rate of Frontier Shift Affecting Electricity DNO Costs, A report prepared for the UK’s Electricity DNOs”, July 2008.
- First Economics – “Frontier Shift: An Update, Prepared for Western Power Distribution”, 22 December 2008.

- NERA – “Real Price Effects: Forecasts for DPCR5, Prepared for EDF Energy”, 25 July 2008.

- NERA – “Real Price Effects: Forecasts for DPCR5 Update, Prepared for EDF Energy”, 18 December 2008.

6.25. The First Economics reports provide estimates of frontier shift for DNOs in DPCR5. One of the building blocks for their estimates is an assumption about input prices. Their forecasts for input prices affecting opex and capex were developed as follows:

- Develop a cost breakdown of the different components within opex and capex for a stylised DNO.

- Develop forecasts of nominal input price inflation for each of the components of opex and capex using evidence from historical trends and judgements about the short-term.

- Develop a weighted average for opex and capex input price inflation using the weights in the stylised DNO.

- Subtract forecasts of RPI from the forecasts of input price inflation to obtain an estimate of input price inflation relative to the RPI.

6.26. The table below presents the forecasts from the December 2008 paper.

Table 6.2 - Forecasts of overall real input price inflation from First Economics December 2008 paper (per cent per annum)

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Opex	4.09	1.21	0.22	0.72	1.22	1.72
Capex	2.93	2.08	0.89	1.39	1.89	2.39

6.27. The July 2008 paper by First Economics did not provide an annual breakdown as above and instead just provided forecasts for the entire period as follows:

- 1.6 per cent per annum real input price inflation for opex.
- 2.4 per cent per annum real input price inflation for capex.

6.28. The changes in the forecasts reflect the impact of the changing macroeconomic conditions between July and December.

6.29. The NERA reports for EDFE focussed on providing forecasts of real price effects for internal labour, contract labour and materials. NERA used the following methods to derive their forecasts:

- Internal labour: Forecasts based on long-term rates of real earnings growth in the economy.
- Contract labour: Estimates based on forecasts of market wage rates for relevant workers.
- Materials: Forecasts based on commodity forward prices and estimates of the lag between changes in commodity prices and changes in producer prices.

6.30. The table below presents the results from the NERA papers.

Table 6.3 - NERA estimates of real price effects (per cent per annum)

Financial year ending		2009	2010	2011	2012	2013	2014	2015
July 2008	Internal labour RPE	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	Contract labour RPE	1	2	2.3	2.3	2.3	2.3	2.3
	Materials RPE	2.9	0	-0.5	-0.2	-0.2	-0.2	-0.2
December 2008	Internal labour RPE	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	Contract labour RPE	1.1	2.9	2.8	2.3	2.3	2.3	2.3
	Materials RPE	4.1	-0.7	-0.2	0	-0.1	-0.1	-0.1

Review of submissions by CEPA

6.31. Ofgem commissioned CEPA to provide a review of these estimates of real price effects and to develop their own forecasts using more up to date information. CEPA completed the analysis at the start of April.

6.32. One of CEPA's criticisms of the First Economics and NERA reports is that they only present point estimates and do not have enough discussion of the uncertainties associated with the forecasts. To address this issue CEPA undertook its forecasting under three different scenarios of macroeconomic performance. CEPA describes these scenarios as follows:

- "Scenario 1, Optimistic Case – In this scenario, a sharp fall in GDP during 2008-09 is followed by a swift recovery and a peak in growth during 2011-12. The economy settles around its trend growth rate of the boom years 1998-2007 (2.8 per cent per annum) and economic activity is high throughout DPCR5.
- Scenario 2, Prolonged Crisis – In this scenario the UK economy contracts from 2008-09 to 2010-11. The recovery in 2011-12 is sharp, but the economy settles into a lower trend growth rate (2.2 per cent per annum) due primarily to increased regulation of financial services, and also to a sharp decline in public expenditure necessary to restore balance to the public finances.
- Scenario 3, Deflation Trap – In this case GDP contracts for three successive years and the rate of recovery is much slower than in either of the two alternative scenarios. As the UK economy struggles to adjust to a new economic environment in which financial services are no longer its main source of value-

added creation, it settles to a trend growth rate that is half the rate observed during the boom years (that is, 1.4 per cent per annum)."

6.33. The report states that these scenarios broadly correspond to V-, U- and L-shaped recessions. For each these scenarios CEPA developed a profile of GDP and RPI growth over the DPCR5 period. They then derived their own forecasts of input price inflation using the historical relationship between RPI inflation and each component of input price inflation. These components were combined using weights derived from their analysis of FBPQ data that was made available to them.

6.34. The table below presents a summary of the results.

Table 6.4 - Average real price effects over the period 2010-11 to 2014-15 (per cent per annum)

	Scenario 1	Scenario 2	Scenario 3
Capital expenditure	0.9	0.7	1.7
Operating expenditure	0.9	0.6	1.8
Total expenditure	0.9	0.6	1.8

6.35. CEPA's forecasts suggest that real price effects will be greatest if there is a prolonged period of deflation. They put this finding down the fact that wages are a large component of expenditure and that wages are sticky and tend not to fall in nominal terms, which can lead to strong real price effects in a deflationary environment.

6.36. Appendix 8 provides more details of CEPA's approach for generating these forecasts.

6.37. We will review this evidence and any new emerging information on input prices when forming our Initial Proposals. We welcome views on the method we should use to set our input price assumptions for DPCR5.

7. Customers

Chapter Summary

This chapter sets out our firm proposals for the mechanism to encourage DNOs to improve the service experienced by worst served customers. We also set out firm proposals for the unplanned elements of the interruptions incentive scheme (IIS) for DPCR5. We are proposing to use the methodologies outlined in this chapter in Final Proposals, with the underlying data being updated to take into account 2008-09 data.

Question 1: Do you agree with the proposed mechanism (in full) for worst served customers?
Question 2: Do you agree with the proposed approach (in full) for setting unplanned targets for customer interruptions and customer minutes lost?
Question 3: Do you think that we should set a cap on the cost per benefitting customers within the worst served customers mechanism and, if so, what level should this be set at?

Introduction

7.1. This chapter sets out our firm proposals for the worst served customer mechanism and the process we propose to use in setting unplanned targets for customer interruptions (CIs) and customer minutes lost (CMLs). We have reviewed the responses to the December Policy Paper and these proposals reflect our further thinking on these two policy areas.

7.2. We consider that it is appropriate to introduce a mechanism to encourage performance improvements for worst served customers but we are proposing a number of changes to the proposals put forward in the December Policy Paper as set out in table 7.1 below.

7.3. For CIs and CMLs we have reviewed the benchmarking methodology, the costs submitted by DNOs to meet the targets we set out in December and compared these with customer willingness to pay. We are not proposing to make further amendments to the quality of supply performance benchmarking methodology[15], but we are proposing a number of changes in how we use this information in setting the targets for DPCR5.

7.4. Our customer research clearly showed that customers have a strong preference that the number of interruptions and minutes lost should not increase from current levels and that there is a lower willingness to pay for further improvements in performance. The package we are proposing reflects these preferences in terms of

[15] Further details are set out in the glossary

the levels of targets we are proposing. In recognition of these findings we do not propose to give DNOs any upfront cost allowances for improved interruption performance but rather we will rely on the incentives to drive the level of expenditure that DNOs make in this area.

Worst served customers

7.5. While the interruptions incentive scheme has been successful at improving average reliability across all customers, it does not appear to be improving performance for those customers experiencing large numbers of interruptions over a number of years. We put forward a number of options for addressing this in the December paper. In this chapter we set out our proposed approach for worst served customers in DPCR5. Table 7.1 below summarises the key elements of the December and May proposals.

Table 7.1 - December and May worst served customers proposals

Key elements	December paper	May paper
Definition of worst served customer	Greater than or equal to five higher voltage interruptions on average over a three year period i.e. 15 over three years	The same - with the caveat of a minimum of three in each year
Required performance improvement	25 per cent reduction in the average number of interruptions for worst served customer	No change from December proposals
Total allowance	£42 million	No change from December proposals
Distribution of allowance pot	Equal split over 13 eligible DNOs i.e. £3.2 million per DNO	Change - propose to distribute according to the number of worst served customers in each eligible[16] DNO
Cap per worst served customer	Cost per benefiting customer should not exceed X (a number to be determined)	Under consideration – we may propose a cap per customer criterion
Customer service reward scheme	Communication with worst served customers	Extend - in addition to communication we envisage looking at innovative schemes and how the allowance has been put to use

Defining the worst served customer

7.6. We propose to make a small modification to the definition of a worst served customer, such that, there are a minimum annual number of interruptions. We propose that this should be three per year, in addition to the requirement that the customer has experienced 15 higher voltage interruptions in three years. This qualification should help mitigate the impact of a single year of uncharacteristically poor performance.

Allowance value and distribution

7.7. In our initial consultation document we set out the three possible mechanisms for targeting the worst served customers: guaranteed standards, a set allowance or

[16] EDFE LPN had no customers that met the definition for worst served customers and as such no allowance is proposed for EDFE LPN.

an incentive. The December paper explained why we felt that guaranteed standards would not drive a substantive change in performance for worst served customers and as a result focussed on the other two proposals.

7.8. The majority of responses were supportive of the allowance mechanism for DPCR5. A few responses indicated that this scheme should migrate toward an incentive based scheme as more reliable information became available. Our view is that a set allowance for DPCR5 will allow the development and implementation of schemes targeted at worst served customers. Additionally, reporting on progress during DPCR5 would provide more reliable information on the associated costs and benefits of these types of schemes. The success and potential modification of this scheme might then be determined as part of the review for DPCR6, depending on the outcome of the RPI-X@20 project.

7.9. In December we proposed the following three options for determining an appropriate allowance amount:

- Based on that currently set for undergrounding in National Parks and Areas of Outstanding Natural Beauty - £64 million,
- Based on the projected costs for worst served customers schemes indicated in the August 2008 FBPQs - £69 million, or
- Based on worst served customers' contribution to the cost of existing quality of service initiatives - £42 million.

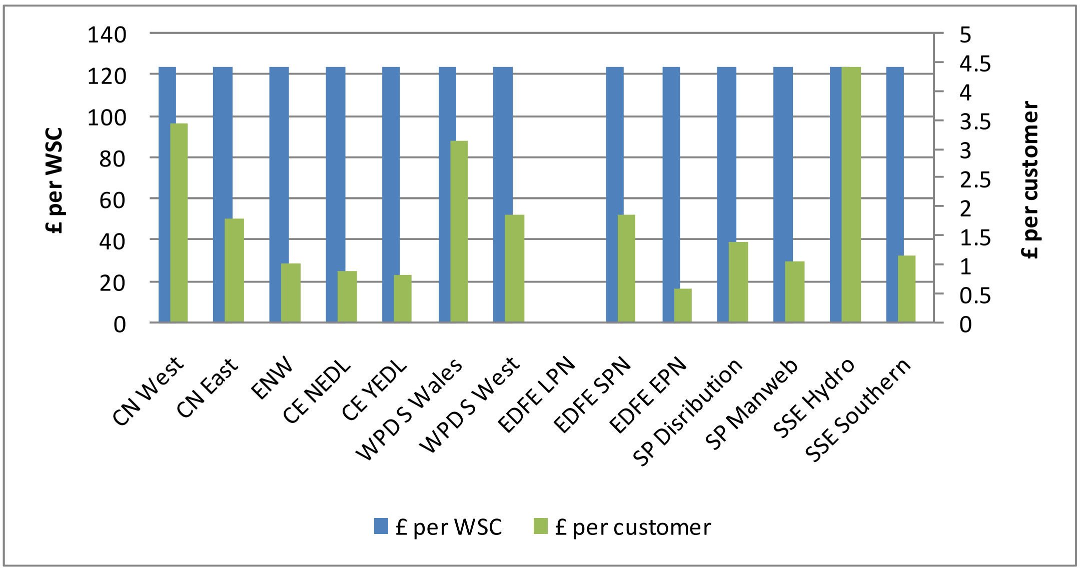
7.10. We propose using the allowance derived from worst served customers' contribution to quality of service initiatives. The rationale for this was that worst served customers pay for, but do not generally receive, the benefit from current quality of service initiatives. The worst served customer allowance would then allow DNOs to invest to the benefit of the worst served. This proposal did not attract significant responses and we propose that the total amount should be £42 million in total over DPCR5 which is roughly double what worst served customers have paid or will be paying for in terms of quality of service improvements.

7.11. As set out in the December paper the allowance will be on a use-it-or-lose-it basis, similar in nature to the current scheme for funding undergrounding in National Parks and Areas of Outstanding Natural Beauty. As per the undergrounding scheme we propose that costs are logged up until the next price review and then be allowed into the RAV on an NPV neutral basis provided that the performance and eligibility criteria are met.

7.12. We also explored a number of options for the distribution of the allowance with our preference in December being for an equal distribution across the 13 eligible DNOs. The majority of responses suggested that it would be more appropriate to base the distribution on the number of worst served customers in each DNO and we are now proposing to base the distribution of the £42 million in DPCR5 across the 13 eligible DNOs according to the number of worst served customers they each have.

The impact of the above proposals in terms of the cost per worst served customer and cost per customer is shown in figure 7.1.

Figure 7.1 - Initial outlay of capex £ per WSC and £ per customer



7.13. The December Policy Paper discussed setting a limit on the average expenditure per benefiting customer. Our analysis of the February FBPQ submissions indicates that the example schemes DNOs put forward have a wide range of costs per benefiting customer. As these were, in most cases, example schemes as opposed to fully worked up proposals we were mindful of placing undue weighting on the information submitted. Given that we are modifying the distribution of the allowance and that there will be a cap on how much customers pay towards these schemes, we would welcome views from stakeholders on whether we should also set a cap on the cost per benefiting customer. If there is no cap per benefiting customer then at the extreme, a DNO could spend the full allowance on a very small number of customers. It is open to question as to whether such customers would want disproportionate amounts to be spent on the network for them, or instead whether they would prefer the equivalent expenditure to simply be given to them. In such circumstances it would therefore be clear that too much money was being spent on benefits that they did not value to the same extent. If a cap were to be applied there is a question as to what level it should be set at, we welcome views on this.

7.14. We also plan to use the customer service reward scheme to highlight best practise in this area and as an additional form of scrutiny for how the proposed DPCR5 allowances are being used.

Unplanned element of quality of service interruptions incentive scheme (IIS)

7.15. In the December policy document we put forward revised unplanned CI and CML targets based on a number of changes to the benchmarking methodology. In February this year we received responses to our proposals and we also received the DNOs' cost estimates to close the gap (if any) between their forecast 2009-10 performance and the targets outlined in the December paper. This section sets out the DNO cost estimates, comparisons with customer willingness to pay (WTP) and the resultant changes to the December draft targets.

7.16. At present we have used the existing DPCR4 revenue exposure levels to outline our proposals and we intend to use the planned customer research this summer to inform our final decision on customers' priorities for DPCR5 and the associated exposure to the incentive scheme.

CI Benchmarking methodology

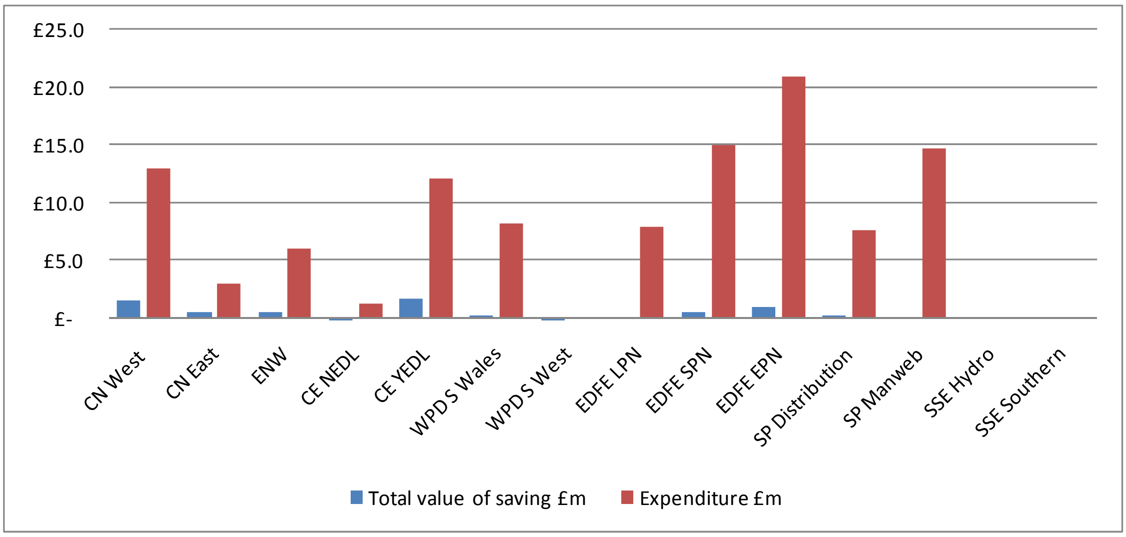
7.17. We use the benchmarking of quality of supply performance across DNOs to inform the scope for improvement both on CIs and CMLs. This is a key input into target setting, together with costs and willingness to pay. We have considered the responses to our December paper and carried out additional analysis to determine whether any further amendments to the benchmarking methodology are required. We have listened to the arguments for and against additional refinements and have concluded that the amendments tabled in the December paper deliver sound and robust benchmarks to inform the target setting debate. We do not propose to make any further methodology changes to the benchmarking.

DNO costs to meet December 2014-15 interruptions targets

7.18. From the February FBPQ submissions DNOs have provided us with information on the costs associated with meeting the 2014-15 targets published in the December paper. Using the customer WTP information from our customer research[17] we have calculated the implied value customers place on the proposed improvements. We have then compared the costs with the implied valuations as shown in figure 7.2 below. In looking across DNO projects and what they are projected to deliver in terms of CIs and CMLs we have found that in all cases the costs significantly exceed the valuation derived from our customer WTP. We propose to take this into account in setting targets for DPCR5.

[17] Expectations of DNOs & willingness to pay for improvements in service, Final Report, July 2008

Figure 7.2 - Costs v WTP for improvements in interruptions performance



CI target setting

7.19. In the December paper we proposed that the starting point for DPCR5 would be the lower of either each DNO's three year average performance or its unplanned target for 2009-10. We proposed that the unplanned target for 2014-15 would be the lower of the benchmark for 2014-15, their 2009-10 target or their average actual performance. For a number of DNOs this resulted in flat targets across DPCR5 whilst for the remainder their targets were set on a glidepath down to their 2014-15 target to close the gap from the starting point in five equal steps.

7.20. As described above in addition to the valuation customers place on interruptions performance we now have the costs that DNOs believe would be necessary in order to meet the proposed December targets. Since December we have carried out further analysis into the drivers of current performance, reviewed how performance has changed from DPCR3 to DPCR4 and looked at DNOs' ability to meet the proposed targets. The factors we propose to take account of in setting the unplanned interruption targets are set out in the paragraphs below.

Locking in the 2009-10 targets

7.21. We no longer consider it to be appropriate to lock in the 2009-10 targets for the DPCR5 period as these targets were tied to cost allowances in the DPCR4 period. To the extent that DNOs judged it was inefficient to make investments for additional CI improvements, the majority of this allowance would have been returned to customers under the rolling capex incentive mechanism. Additionally, as we now have a much longer period of data with which we can carry out benchmarking and associated analysis our view is that it is more appropriate to base targets for DPCR5 using this data. Our customer research indicated that customers did not want performance to deteriorate from current levels. The removal of the 2009-10 targets is consistent with this customer preference as they do not represent the performance experienced by customers.

Average and base case performance

7.22. Where the current average performance or forecast performance delivered by the DNO's own base case is better than the 2014-15 benchmark then we propose, in the interests of customers, to lock this performance in, by taking the best performance as the target(s) for DPCR5.

Performance above the benchmark

7.23. Where the 2014-15 benchmark is tighter than the DNO's current performance and their base case proposal, we have looked at performance over a longer timeframe to determine whether they have been improving or deteriorating over time. Where performance has been deteriorating we have looked at whether this is due to atypically high fault rates in recent years and where this is the case we have taken a longer run average fault rate.

Cost allowances

7.24. The costs of schemes proposed by DNOs to meet our December targets significantly exceed the valuation derived from our customer WTP. We also believe that it should be the incentive rate that drives DNO decision making about expenditure to improve quality of supply performance. As such we do not propose to give DNOs any up-front allowances for either CI or CML improvements in DPCR5.

7.25. Paragraphs 1.8 to 1.11 in appendix 10 set out our proposed approach to CI target setting for the DPCR5 period.

7.26. The revised unplanned interruptions targets are set out in table 7.2 below.

Table 7.2 - Proposed unplanned CI targets for DPCR5

DNO	Start Point[18]	2010-11	2011-12	2012-13	2013-14	2014-15
CN West	105.0	104.6	104.2	103.8	103.5	103.1
CN East	75.3	74.8	74.4	73.9	73.4	73.0
ENW	N/A	49.5	49.5	49.4	49.4	49.4
CE NEDL	64.0	63.9	63.8	63.8	63.7	63.6
CE YEDL	68.0	67.8	67.6	67.5	67.3	67.1
WPD S Wales	77.8	77.3	76.8	76.3	75.9	75.4
WPD S West	N/A	71.9	71.9	71.9	71.9	71.9
EDFE LPN	N/A	33.0	33.0	33.0	33.0	33.0
EDFE SPN	81.6	81.1	80.6	80.1	79.6	79.0
EDFE EPN	70.8	70.7	70.5	70.4	70.2	70.1
SP Distribution	N/A	59.1	58.9	58.8	58.7	58.7
SP Manweb	N/A	42.3	42.2	42.0	41.8	41.7
SSE Hydro	N/A	68.3	68.3	68.3	68.3	68.3
SSE Southern	71.1	71.0	70.8	70.7	70.6	70.5

7.27. The impact of the changes between the targets in the December paper and those proposed in this paper are set out in table 7.3 below.

[18] See appendix 10 for details regarding those DNOs that do not have a startpoint listed and for details of the calculation of startpoints

Table 7.3 - Difference between December and May unplanned CI targets

DNO	2010-11	2011-12	2012-13	2013-14	2014-15
CN West	4.5	4.1	3.7	3.4	3.0
CN East	1.5	1.8	1.9	2.1	2.4
ENW	-1.3	-1.3	-1.4	-1.4	-1.4
CE NEDL	0.0	-0.1	0.0	0.0	0.0
CE YEDL	1.2	1.0	0.9	0.7	0.5
WPD S Wales	0.5	0.9	1.4	1.9	2.4
WPD S West	-2.0	-1.9	-1.9	-1.8	-1.8
EDFE LPN	0.0	0.0	0.0	0.0	0.0
EDFE SPN	0.6	0.8	1.0	1.2	1.4
EDFE EPN	0.0	0.0	0.0	0.0	0.0
SP Distribution	-0.1	-0.2	-0.2	-0.1	0.0
SP Manweb	0.0	-0.1	-0.3	-0.5	-0.6
SSE Hydro	0.0	0.0	0.0	0.0	0.0
SSE Southern	0.0	0.0	0.0	0.0	0.0

CML benchmarking and target setting methodologies

7.28. For the December paper we set the 2014-15 unplanned CML targets using the lower of the current three year DPCR4 average, the 2014-15 benchmark and the 2009-10 target. The 2014-15 benchmark was built up by applying the CML per CI benchmark for the different voltages, 132kV, EHV, HV and LV to their respective proportion of the 2014-15 CI target. In doing so the methodology implied, as was the case for DPCR4, that any required improvement in CIs would be delivered at the HV level. This is shown in table 4 in appendix 10.

7.29. We propose to use the same methodology for setting the unplanned CML benchmarks as was set out in the December paper.

7.30. For the four frontier CI performers, ENW, EDFE LPN, SP Manweb and SSE Hydro, we have used their implied 2014-15 CI benchmarks and applied the benchmark CML per CI values at the different voltages to calculate their 2014-15 CML benchmarks. This follows the approach set out in paragraph 1.65 of appendix seven to the December paper.

7.31. In all cases we are taking the lower of average DPCR4 performance, DNO base case and the 2014-15 benchmark in setting the 2014-15 target. As with CIs we are removing the stipulation that the targets are at least as tight as the 2009-10 targets and we are also not giving any cost allowances. This stipulation applied to two DNOs in December, CE YEDL and SP Distribution. A more detailed description of how we have established the 2014-15 unplanned CML targets is set out in table 5 in appendix 10.

7.32. The startpoint for each DNO has been taken as the lower of their DPCR4 average and base case proposal. Where there is a gap between the startpoint and the 2014-15 target we have, as was the case in the December paper and at DPCR4, profiled five even steps down to the 2014-15 target. Again, we have removed the December paper proposal that the startpoint is at least as tight as the 2009-10 target. This previously set the startpoints for CN West, CN East, CE YEDL, EDFE SPN, SP Distribution and SP Manweb. A comparison of how the startpoints have been calculated in December and May is set out in table 6 in appendix 10.

7.33. The proposed unplanned CML targets are set out in table 7.4 below and the comparison with the December targets is set out in table 7.5.

Table 7.4 - Proposed unplanned CML targets for DPCR5

DNO	Start Point	2010-11	2011-12	2012-13	2013-14	2014-15
CN West	89.7	87.7	85.7	83.7	81.7	79.7
CN East	65.5	64.2	62.8	61.5	60.2	58.9
ENW	48.1	48.0	48.0	47.9	47.8	47.7
CE NEDL	58.2	57.6	57.1	56.5	55.9	55.4
CE YEDL	68.0	66.5	65.1	63.6	62.1	60.6
WPD S Wales	39.9	39.9	39.9	39.9	39.9	39.9
WPD S West	42.7	42.7	42.7	42.7	42.7	42.7
EDFE LPN	39.1	39.0	38.8	38.7	38.6	38.5
EDFE SPN	83.8	78.9	73.9	69.0	64.1	59.1
EDFE EPN	62.1	60.7	59.3	57.8	56.4	55.0
SP Distribution	54.2	53.5	52.8	52.0	51.3	50.6
SP Manweb	53.9	53.1	52.2	51.4	50.6	49.7
SSE Hydro	58.6	58.6	58.6	58.6	58.6	58.6
SSE Southern	64.8	63.5	62.2	60.9	59.7	58.4

Table 7.5 - Difference between December and May unplanned CML targets

DNO	2010-11	2011-12	2012-13	2013-14	2014-15
CN West	7.5	5.6	3.8	1.9	0.0
CN East	3.6	3.0	2.5	2.1	1.6
ENW	-0.5	-0.3	-0.2	-0.1	0.0
CE NEDL	0.0	0.0	0.0	0.0	0.0
CE YEDL	8.9	7.5	6.0	4.5	3.0
WPD S Wales	0.0	0.0	0.0	0.0	0.0
WPD S West	-0.5	-0.5	-0.5	-0.5	-0.5
EDFE LPN	0.0	0.0	0.0	0.0	0.0
EDFE SPN	18.5	14.0	9.7	5.3	0.8
EDFE EPN	-0.3	-0.2	-0.2	-0.1	0.0
SP Distribution	6.4	5.7	4.9	4.2	3.5
SP Manweb	2.3	1.6	1.1	0.6	-0.1
SSE Hydro	0.0	0.0	0.0	0.0	0.0
SSE Southern	0.0	0.0	0.0	0.1	0.0

Incentive rates and revenue exposure to the scheme

7.34. There were generally consistent results from our customer research for DPCR5 in respect of willingness to pay for further improvements in interruptions and duration performance, with the exception of EDFE LPN[19]. These results contrast with the current DPCR4 incentive rates, where there is a wide spread across the 14 DNOs. Given these results and our preference for the incentives to drive performance in DPCR5 we are proposing to move to more equal incentive rates across the DNOs for CIs and CMLs in DPCR5.

7.35. Our view is that there is merit in a gradual movement to more equal incentive rates, on a per customer basis, to avoid undue distortions in DNO investment decision making across price controls. Where there are differences between the current DPCR4 incentive rates and those implied by the willingness to pay we propose to close half of the difference in DPCR5. Tables 7 and 8 in appendix 10 show 2007-08 CI and CML incentive rates per customer in 2007-08 prices, willingness to pay per customer, gaps between these values and the proposed DPCR5 CI and CML incentive rates per customer.

[19] Nationally the willingness to pay per customer to reduce one interruption was £4.02, except in EDFE LPN where this was £13.46 per customer. The willingness to pay to reduce the length of an interruption by one minute was £0.07 for ten of the DNOs. The exceptions were EDFE LPN at £0.06, SSE Hydro at £0.12, ENW at £0.16 and SP Manweb at £0.04.

Revenue exposure to the scheme

7.36. The amount of revenue/return on equity exposed to the incentive scheme will be decided as part of the full price control package, therefore this section uses the current revenue exposure of three per cent of base revenue split across CIs and CMLs at 1.2 per cent and 1.8 cent respectively. We have compared the most recent year for which data is available, 2007-08, with the proposals for DPCR5 and the DPCR5 proposals similarly utilise 2007-08 data where necessary for consistency. All of the information has been put on the same 2007-08 price basis.

7.37. The December paper showed that by moving to equal incentive rates per customer then another element of the incentive structure has to flex. As we are proposing to move to more equal incentive rates per customer in DPCR5 then an additional element of the scheme will need to flex alongside still variable incentive rates per customer, as set out in table 7.6. We are proposing that the same proportion of revenue/return on equity be exposed for each DNO and working from the proposed incentive rates per customer in tables 7 and 8 in appendix 10 results in the following incentive rates per CI and per CML in tables 7.7 and 7.8 respectively.

Table 7.6 - Key elements of the scheme

Element	DPCR4	DPCR5
Incentive rate per customer	Variable	Variable (moving to more equal)
Incentive rate per CI/CML	Variable	Variable
Revenue exposure	Fixed	Fixed
Bandwidth	Fixed	Variable

Table 7.7 - Revenue exposure to CIs and incentive rates per CI

DNO	2007-08 base revenue £m	1.2% of base revenue £m	2007-08 incentive rate per CI	DPCR5 incentive rate per CI	Percentage change
CN West	£ 274	£ 3.3	£ 0.13	£ 0.12	-6%
CN East	£ 276	£ 3.3	£ 0.18	£ 0.15	-13%
ENW	£ 253	£ 3.0	£ 0.21	£ 0.17	-19%
CE NEDL	£ 175	£ 2.1	£ 0.12	£ 0.10	-17%
CE YEDL	£ 228	£ 2.7	£ 0.16	£ 0.14	-16%
WPD S Wales	£ 165	£ 2.0	£ 0.08	£ 0.07	-15%
WPD S West	£ 201	£ 2.4	£ 0.12	£ 0.10	-17%
EDFE LPN	£ 256	£ 3.1	£ 0.35	£ 0.35	-1%
EDFE SPN	£ 192	£ 2.3	£ 0.11	£ 0.11	1%
EDFE EPN	£ 329	£ 4.0	£ 0.19	£ 0.18	-6%
SP Distribution	£ 332	£ 4.0	£ 0.27	£ 0.19	-28%
SP Manweb	£ 195	£ 2.3	£ 0.21	£ 0.15	-30%
SSE Hydro	£ 195	£ 2.3	£ 0.09	£ 0.07	-23%
SSE Southern	£ 385	£ 4.6	£ 0.21	£ 0.18	-15%
Average			£ 0.18	£ 0.16	-13%

Table 7.8 - Revenue exposure to CMLs and incentive rates per CML

DNO	2007-08 base revenue £m	1.8% of base revenue £m	2007-08 incentive rate per CML	DPCR5 incentive rate per CML	Percentage change
CN West	£ 274	£ 4.9	£ 0.18	£ 0.19	6%
CN East	£ 276	£ 5.0	£ 0.24	£ 0.22	-5%
ENW	£ 253	£ 4.6	£ 0.27	£ 0.35	28%
CE NEDL	£ 175	£ 3.2	£ 0.16	£ 0.14	-13%
CE YEDL	£ 228	£ 4.1	£ 0.21	£ 0.20	-5%
WPD S Wales	£ 165	£ 3.0	£ 0.14	£ 0.12	-16%
WPD S West	£ 201	£ 3.6	£ 0.20	£ 0.17	-17%
EDFE LPN	£ 256	£ 4.6	£ 0.40	£ 0.29	-27%
EDFE SPN	£ 192	£ 3.5	£ 0.16	£ 0.17	4%
EDFE EPN	£ 329	£ 5.9	£ 0.29	£ 0.29	-3%
SP Distribution	£ 332	£ 6.0	£ 0.35	£ 0.27	-23%
SP Manweb	£ 195	£ 3.5	£ 0.26	£ 0.17	-33%
SSE Hydro	£ 195	£ 3.5	£ 0.13	£ 0.12	-10%
SSE Southern	£ 385	£ 6.9	£ 0.31	£ 0.27	-11%
Average			£ 0.25	£ 0.23	-8%

Bandwidths around the targets

7.38. The bandwidth around the target sets the performance bounds associated with either maximum outperformance (reward) or maximum underperformance (penalty). Performance itself can exceed these bounds, but customers' exposure in the case of outperformance and DNO's exposure in the case of underperformance is capped at the lower and upper bounds respectively. We propose that the bandwidth around each DNO's CI and CML targets also varies rather than being a fixed proportion of the target as was the case for DPCR4, 25 per cent and 30 per cent for CI and CML respectively. Table 7.9 shows the bandwidths around the 2009-10 and 2014-15 CI and CML targets. Tables 9 and 10 in appendix 10 translate these bandwidths into the upper bound penalty and lower bound reward values associated with the 2009-10 and 2014-15 CI and CML targets respectively.

Table 7.9 - Percentage bandwidths around the 2009-10 and 2014-15 CI and CML targets

DNO	2009-10 CI bandwidth	2014-15 CI bandwidth	Difference	2009-10 CML bandwidth	2014-15 CML bandwidth	Difference
CN West	25%	26%	1%	30%	33%	3%
CN East	25%	30%	5%	30%	38%	8%
ENW	25%	36%	11%	30%	28%	-2%
CE NEDL	25%	34%	9%	30%	40%	10%
CE YEDL	25%	29%	4%	30%	34%	4%
WPD S Wales	25%	38%	13%	30%	63%	33%
WPD S West	25%	34%	9%	30%	51%	21%
EDFE LPN	25%	27%	2%	30%	41%	11%
EDFE SPN	25%	27%	2%	30%	34%	4%
EDFE EPN	25%	32%	7%	30%	38%	8%
SP Distribution	25%	35%	10%	30%	43%	13%
SP Manweb	25%	38%	13%	30%	41%	11%
SSE Hydro	25%	48%	23%	30%	51%	21%
SSE Southern	25%	37%	12%	30%	44%	14%

Exceptional events

7.39. We propose to continue with a severe weather exceptional events mechanism with thresholds based on eight times the daily average number of higher voltage incidents. We will update the thresholds once we have all of the 2008-09 interruptions data. We are not proposing to introduce an additional materiality test into severe weather exceptional events, but we will ensure that there is greater clarity in the licence for DPCR5 as to whether an event qualifies as a severe weather or one-off exceptional event. We also propose to continue with a one-off exceptional event mechanism and will look to allow consideration of incidents currently deemed to be within the DNO's control within the process. The final targets for DPCR5 will reflect any proposed amendments to the existing DPCR4 mechanism.

8. Network output measures

Chapter Summary

This chapter provides an update on the development of network output measures. We include a summary of the outputs proposed by DNOs as part of their February forecasts and Ofgem's current thinking on a common methodology for reporting outputs related to expenditure on general reinforcement and asset replacement. We also discuss how outputs will be developed for Initial Proposals and how outputs will be used in DPCR5.

Question 1: Is Ofgem's proposed methodology for general reinforcement and asset replacement outputs appropriate?
Question 2: Is Ofgem's proposed approach for other areas of investment appropriate?
Question 3: What approach should be taken if a DNO fails to deliver the agreed outputs i.e. how could the incentives be adjusted?
Question 4: Do you consider that the output measures proposed provide sufficient protection in their own right, or is it appropriate to have some form of additional safety net in the DPCR5 settlement, for example through monitoring investment volumes?
Question 5: Should there be an obligation on DNOs to further develop output measures during DPCR5?
Question 6: We seek views from stakeholders on the role that outputs should play in DPCR5 and particularly how they can best be implemented and used.

Background

8.1. In the previous two consultation documents we highlighted that we have few output measures; that is measures of what DNOs deliver in return for the revenues they collect from customers. In particular there is no measure of what customers gain from investment in network assets, which can account for a high proportion of network costs. In the absence of such output measures it is difficult for us to distinguish between DNOs that are performing well and those that are not. Where DNOS have made less investment expenditure than expected at the time the price control was set, it is difficult to distinguish whether this is because the company has innovated and found ways to deliver what customers need more efficiently or because they have deferred expenditure at the expense of network health.

8.2. In this price control review we are placing a strong emphasis on the need for DNOs to develop suitable network output measures and to commit to delivering against these measures as part of the price control settlement. We intend that, where possible, the output measures developed should be high level measures capturing network risk, rather than measures relating directly to volume of work (e.g. number of assets installed). We will be looking to the DNOs to stipulate the levels of output that they consider they should achieve by the end of the DPCR5 period based on their own judgement of an appropriate level of risk on their networks and informed by discussions with their stakeholders.

8.3. The output measures we set out in this chapter are primarily focused on capturing what the DNO achieves through asset replacement expenditure (where outputs are related to the health of the network and the risk of loss of supply), and through expenditure on reinforcement (where outputs are related to the ability of the network to meet changes in the use of the network, including by distributed generation). These categories of expenditure account for 78 per cent of core forecast network investment in DPCR5. These measures will augment the measures we have of DNO performance on interruption, network losses and on customer satisfaction. They will provide a much greater level of protection to customers through:

- giving greater clarity over the outputs DNOs are expected to deliver in return for the agreed revenue allowances,
- allowing Ofgem to assess whether any underspend against the agreed allowance is due to efficiency measures or to a deterioration in performance,
- allowing Ofgem to make a better assessment of DNOs' long term asset stewardship, and
- encouraging DNOs to improve the way they plan and operate the networks with a focus on the outputs that will be delivered.

8.4. All of the above will ensure that the DPCR5 settlement provides value for money to customers.

8.5. In the December Policy Paper we noted that DNOs that do not provide sufficient network output information as part of the DPCR5 process will 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.

8.6. We also noted that, if a company is unable to provide adequate output measures, we may constrain their ability to outperform against the weighted average cost of capital (WACC). Alternatively we could take other measures to reflect the greater scope that company will have to increase shareholder returns at the expense of customers, for example, by allowing network condition to deteriorate to inefficient levels. In such cases it may be appropriate to apply a different information quality incentive (IQI) matrix, for example, with lower levels of additional income and to retain the option of an ex-post review. We may also place more emphasis on input type measures.

8.7. The DNOs have all made substantial progress towards providing us with adequate output measures. There is some work still to be done to the outputs submitted in February, and some DNOs have made faster progress than others or are starting from a position of better data. However, if the momentum achieved to date is sustained we would hope that there is no need for action along the lines set out above.

Types of output measure

8.8. In order to implement output measures for DPCR5 we need to:

- agree which of the output measures proposed by the DNOs are fit for purpose,
- establish the framework for presenting the level of outputs against the common methodology,
- agree the level of outputs each DNO will deliver in return for allowed revenues,
- introduce licence conditions to capture the agreed outputs per DNO and the process to be applied where DNOs underperform against these, and
- establish the process for the reporting and audit of outputs.

8.9. When deciding whether proposed output measures are fit for purpose it is useful to consider the type of output measure being proposed. Output measures can be categorised into three tiers:

- Tier one: High level system wide risk metrics, derived from the amalgamation of well defined, established and consistently reported site or asset specific metrics, e.g. measures which reflect the level of risk on the system as a whole.
- Tier two: Site or asset specific based metrics, which capture factors that impact on performance and/or the relative level of risk for the asset or site in question, e.g. metrics collating asset condition and health information.
- Tier three: Low level metrics capturing volumes of activity e.g. number of assets installed. This third tier is comprised of input measures.

8.10. We do not consider it is appropriate to require DNOs to commit to the inputs they will deliver through the DPCR5 period, as this will restrict the companies' ability to capture efficiencies by altering their investment strategy or to respond to changing circumstances or changes in customer needs. However, we think it is achievable for DNOs to commit to a package of site or asset specific metrics (tier two outputs) as part of the DPCR5 settlement. As part of the ongoing work on outputs during DCPR5, DNOs will be encouraged to develop system wide (tier one) output measures by building on the underlying site or asset specific metrics.

8.11. The obligation will be on DNOs to meet agreed tier two outputs. However, in the absence of historical information Ofgem must be confident that movements in the proposed tier two outputs adequately reflect changes in expenditure levels and the volume of work undertaken taking account of any efficiencies.

8.12. The most recent Ofgem Electricity Transmission Cost report notes that 2007-08 “saw significant increases in the price of some capital goods; as a result forecast capital volumes are lower than anticipated. The main area of concern is the reduction in the quantity of asset replacement expenditure by NGET" and "although NGET's capital spend is close to the TPCR4 forecasts, the volume of capital work anticipated by NGET is significantly lower…" At the time of the TPCR4 settlement, forecast capital spend was not associated with agreed outputs, although the transmission companies have since been working to define better output measures. This makes scrutiny of the transmission companies' capital spend more challenging.

8.13. While the situation may be different for electricity distribution, as we are looking to introduce outputs as part of the DPCR5 settlement from the beginning, the outputs are nevertheless at a relatively early stage in their development and it may be important to monitor that they are adequately reflective of changes in expenditure and that they are based on good information. Therefore we are considering whether it is appropriate to have a safety net for customers relating to significant reductions in the volume of network investment.

8.14. We consider suitable tier two network output measures should be:

- measurable, controllable, auditable and replicable over time,
- aligned with the underlying business processes that are used to plan and operate the network,
- sensitive to the level of investment, and
- able to capture outputs or outcomes such as performance, asset health, network capacity or headroom or network risk.

8.15. As part of the February FBPQ DNOs were requested to provide output measures consistent with these requirements to support their forecast expenditure for network investment. In the Policy Paper we set out that the main focus will be on outputs that address general reinforcement and condition based asset replacement.

Overview of DNO outputs suggested in the main FBPQ

8.16. The quality of the output measures and supporting information proposed by the DNOs in the February FBPQ submissions is a significant improvement on the output measures DNOs provided in the August submissions. There is still a range in the robustness in what has been provided, with a number of DNOs proposing outputs in some areas that are still some way from what we would consider to be fit for purpose. Based on progress to date, including work undertaken since submission of the FBPQs, we think it is possible for all DNOs to submit fit for purpose outputs that can be used as part of the DPCR5 settlement.

8.17. The following table summarises Ofgem's initial view of the DNOs' proposed output measures for general reinforcement and asset replacement. This view was formed based on what was presented in the FBPQ prior to any detailed discussion with the DNOs. Further details of the outputs proposed by each DNO are shown in appendix 11.

Table 8.1 - Initial view of DNO proposed outputs

DNO	Buy in from DNO	FBPQ		Committed to the developed of a common methodology
		General Reinforcement	Asset replacement	
CN	Yes	Potential	Yes	Yes
ENW	Yes	No	Yes	Yes
CE	Yes	Yes	Yes	Yes
WPD	Yes	No	Yes	Yes
EDFE	Yes	No	Yes	Yes
SP	Yes	Yes	Yes	Yes
SSE	Yes	No	Yes	Yes

8.18. Across the industry asset replacement output measures are further developed than those for general reinforcement. For asset replacement the proposed outputs are based on a combination of failure rates and health indices. For general reinforcement a number of DNOs are proposing outputs which take account of some or all of the following factors:

- peak load over firm capacity,
- duration peak load is over firm capacity,
- customers at risk,
- level of interconnection, and
- demand growth.

8.19. Across the other areas of investment DNOs have proposed a range of outputs. In a number of cases the outputs proposed are essentially input measures e.g. number of flood defences installed. We will consider the outputs proposed by the DNOs in assessing their appropriate levels of network investment but at this stage we are not proposing to introduce formal output measures relating to the other areas of investment into the regulatory settlement. The DNO proposals for these other areas are summarised in appendix 11.

Ofgem view

8.20. We have recently provided feedback to all the DNOs regarding their proposed outputs measures for general reinforcement and asset replacement. This included feedback on where we perceived there to be a gap between what had been presented by the DNO, what other DNOs had provided and Ofgem's minimum requirements.

8.21. Based on the information provided as part of the FBPQs and further discussions at the bilateral meetings Ofgem's view is that a common methodology for outputs related to general reinforcement (EHV and 132 kV) and asset replacement is appropriate and can be achieved for the DPCR5 settlement. All DNOs have agreed to assist in developing outputs consistent with a common methodology.

8.22. At present Ofgem considers that the outputs proposed against the envisaged output measures will not be suitable for benchmarking. This is due to differences in reporting which are likely to make such comparisons misleading. These include:

- definitional differences,
- data issues,
- different levels of network risk (including different starting positions and future movements), and
- a lack of historical data.

8.23. For DPCR5 outputs will be used to assess an individual DNO's performance over time. Ofgem intends that outputs should be further developed during DPCR5 to enable benchmarking between DNOs where possible and if required for future settlements.

8.24. Where DNOs have proposed outputs over and above the common methodology the DNO will be able to choose between committing to these as part of the formal output measures in addition to the common methodology or providing them as additional information to aid the further development of output measures without forming part of the formal output measures.

8.25. Ofgem's proposed methodology is outlined in table 8.2 below. Further details are provided in appendix 11.

Table 8.2 - Summary of Ofgem’s proposed common methodology

Area of investment	Ofgem proposals
General reinforcement (EHV and 132 kV)	Load Index (LI) profile based on load (MVA) over firm, duration over firm and forecast load growth. In addition information on the total number of customers supplied by substations within each LI band will be collected.
Asset replacement	Asset condition or Health Index (HI) profile. Fault rates of LV and HV overhead lines, underground cables and other assets where HI are not fully developed.
Other areas of investment not covered by existing incentives or output measures	No formal output measures as current proposals are mostly input measures. Licence condition to develop output measures during DPCR5.

General reinforcement and asset replacement

8.26. We propose to use an index based approach to develop output measures for both general reinforcement and asset replacement expenditure. DNOs will assign each substation with a Load Index (LI) based on fixed criteria around the need for reinforcement. DNOs will assign each individual asset with a Health Index (HI) based on fixed criteria around the need for replacement. For example, in the case of HI, poorer asset condition will result in a higher index. The individual LI and HI per asset will be collated to provide the overall profile for each DNO.

8.27. We propose a one to five banding for both LI and HI. This will allow the indices to be presented in a consistent format. In practice, each DNO may take a slightly different view as to which HI or LI band a particular asset falls into and so the absolute magnitudes and therefore level of risk associated with a given band will not be fully comparable across DNOs. Further details on our proposals for LI and HI are provided in appendix 11.

8.28. For both LI and HI the DNOs will be required to provide us with:

- The current profile (year 0) – for LI this will be the total number of substations in each of the five bands. For HI this will be the total number of assets for each asset category in each of the five bands.

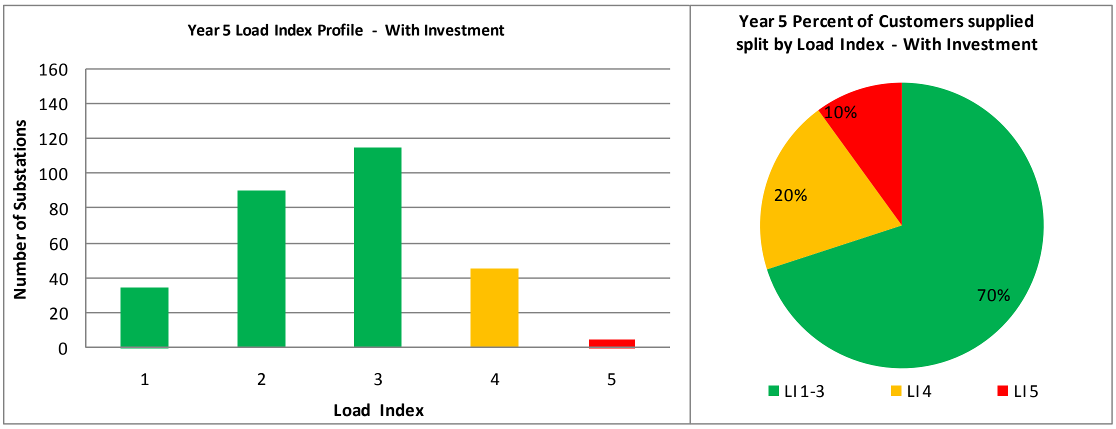
- Their forecast profile (year five) with no intervention – for LI this will reflect the DNO's view on the impact of load growth. For HI this will reflect the DNO's view on the degradation of asset condition over time.

- Their forecast profile (year five) with investment - this will reflect the DNO's view of how the current profile will be impacted by the proposed level of investment. This is the output the DNO will be committing to deliver as part of the DPCR5 settlement.

- For LI - the total number of customers supplied by substations within each LI band will also be required.

8.29. An example of a how the LI profile could be presented is shown below. The HI profile could be presented in a similar way.

Figure 8.1 - Example of a graphical summary of the LI profile



Fault rates

8.30. For some assets, particularly for those assets at LV and HV where there is no redundancy built into the network, fault rates provide a useful indicator of asset health. For LV and HV overhead line (OHL) and cable replacement DNOs will be required to provide information on fault rates similar to the information provided on HI. Even if the DNO can provide HI for LV and HV OHL and cables are available, they will also be required to provide:

- The current (year 0) fault rate - this will reflect the DNO's view of the current fault rate.
- Forecast fault rate (year five) with no intervention – this will reflect the DNO's view of the impact of degradation of asset condition over time and the corresponding impact on fault rate.
- Forecast fault rate (year five) with investment - this will reflect the DNO's view of how the current fault rate will be impacted by the DNO's proposed level of investment. This is the output the DNO will be committing to deliver as part of the DPCR5 settlement.

8.31. In addition for any asset groups where HI are yet to be developed or where there is inadequate condition information DNOs will be required to provide fault rate information.

8.32. For assets where fault rates are very low or not reflective of asset condition we will monitor volumes of assets replaced but will not hold the DNOs to formal output measures as part of the settlement. In this case, given the lack of condition information, we will be more inclined to use the output of our high level modelling to set volumes and therefore allowances.

Output measures – other areas of investment

8.33. A number of the other areas of investment are covered by existing outputs or incentives (or proposed incentives). Areas of investment not covered are:

- LR3 - Diversions,
- LR4 - LV and HV general reinforcement,
- LR6 - Fault Level,
- NL8 - Operational IT and telecoms, and
- NL9 - Legal and Safety.

8.34. The overall level of materiality for these areas is much lower than for EHV and 132kV general reinforcement and asset replacement and differs significantly across DNOs. Across the industry these areas represent 22 per cent of core network investment forecasts. For these areas we propose to monitor tier three outputs without holding the DNOs to formal output measures as part of the settlement. We will require DNOs during DPCR5 to develop suitable tier two output measures for these areas of investment.

Development of outputs for Initial Proposals

8.35. In the lead up to Initial Proposals Ofgem will work with the DNOs to refine the common methodology to develop output measures, including developing the definitions of the bands for LI and HI. For LI this will also involve the development of a logic table for assigning LIs. (This is discussed in more detail in appendix 11) For HI DNOs will need to develop an approach to map their internal HI into the common methodology.

8.36. In addition we will develop a common reporting template and graphical summary. Examples of a draft reporting template and graphical summary are provided in appendix 11.

8.37. Once the approach has been refined and agreed the DNOs will be required to update and resubmit their outputs against the proposed common methodology for general reinforcement and asset replacement.

8.38. These outputs will be published as part of the Initial Proposals. From that point on, there will be a link between the level of investment proposed in Initial Proposals and the outputs DNOs are expected to deliver.

8.39. After Initial Proposals are published there will be an iterative process between Ofgem and the DNOs to finalise network investment allowances and the associated level of outputs that the DNOs commit to as part of the settlement.

Role of outputs in DPCR5

8.40. During the DPCR5 period we will monitor DNO output measures on an annual basis to ensure that the DNOs deliver the outputs that have been agreed in exchange for the allowed revenue.

8.41. Leading up to Final Proposals Ofgem will work with the DNOs to establish a more detailed framework for how the outputs will be implemented and used in practice. The framework will need to address the following issues:

- how the DNO commitment to achieving particular network investment outputs will be captured in the licence,
- the detailed annual process for reporting and monitoring outputs,
- the approach that will be taken if a DNO fails to deliver the agreed outputs i.e. how the incentives will be adjusted, and
- the approach that will be taken if a DNO is found to have provided poor or misleading information which impacted on the setting of the required outputs.

8.42. The regulatory arrangements may need to provide some flexibility for DNOs to reprioritise the target HI and LIs where this is demonstrably in customers' interests. For example, reprioritisation may be appropriate if levels of demand outturn at very different levels to those assumed in the DNO's business plans. We also need to do further work to consider:

- if and how new or improved information, for example about the deterioration rate of a particular asset, will be used to adjust the target outputs, and
- if and how unforeseen external events that impact the DNO, for example major changes in government energy policy, are taken into account.

8.43. For DPCR5 we are considering placing an obligation on DNOs to work towards the development of both network wide tier one outputs which capture overall network risk and tier two outputs for areas of investment not addressed by the common methodology for general reinforcement and asset replacement.

9. Cost Incentives

Chapter summary

This chapter considers our approach to equalising incentives and the information quality incentive.

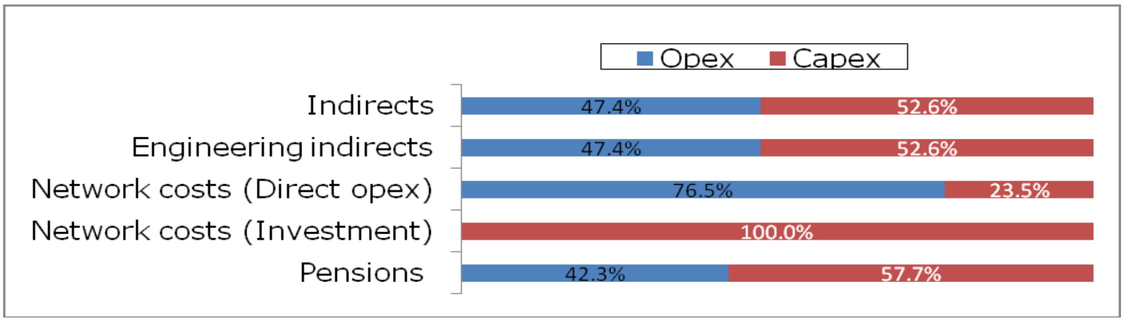
Question 1: Do you agree with our proposed approach to equalising incentives?
Question 2: Have we identified the most appropriate costs to be within the equalised incentive and the IQI?
Question 3: How should we set the "RAV additions percentage" that will determine the split between split between "slow" and "fast" money?

Equalising incentives

Summary of the issue

9.1. There are currently imbalances between the incentives for different types of costs under the DPCR4 RAV rules. These imbalances may distort the decisions that DNOs need to make between capex and opex solutions and create boundary issues. DNOs bear the full cost of each additional £1 classified as opex but only 29p to 40p for each additional £1 that is capitalised. 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 9.1 - Capitalisation of costs for different activities at DPCR4



9.2. 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. We have worked to minimise DNOs' latitude to characterise costs differently through the annual cost reporting review, but this process has illustrated the difficulties of doing so. We recognise, too, that some issues are created by differences in DNOs' business models, as well as genuine disagreements over appropriate definitions of cost categories.

9.3. The balance of incentives is particularly important in the context of large increases in forecast costs. 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. Given the climate change agenda, it is also important that the price control does not reduce the incentive on DNOs to adopt non-network solutions such as demand-side management or contracting with distributed generation to manage constraints.

9.4. 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.

Options set out in the December Policy Paper

9.5. Our December policy consultation set out the following as potential options for moving towards more equal incentives:

- 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.
- 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.
- 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.

Summary of responses to the Policy Paper

9.6. With the exception of one DNO (SSE) there was general support for the proposal to equalise incentives. There were, however, mixed views among these respondents over how such a proposal should be implemented.

9.7. For example, ENW favour the option of fixing the proportion of total costs that enter the RAV and suggest that this proportion should be determined to ensure financeability for each individual DNO. They believe that such an approach could reduce the regulatory burden on both DNOs and on Ofgem. CE suggested that the overall proportion of costs to be capitalised should be estimated using the overall proportions determined under the DPCR4 methodology as they think that was broadly the right level. WPD also identified scope for the equalisation of incentives to lead to a reduction in the regulatory burden as they feel the current rules are too complicated.

9.8. SP acknowledge that capitalising a fixed proportion of all expenditure would be the simplest approach but emphasise the importance of the percentage chosen. They are keen that the value of the RAV is not distorted by such a policy.

9.9. In contrast, CN's preference is to capitalise costs as closely as possible to their nature, using statutory accounting drivers or relevant proxies wherever possible.

9.10. SSE was the only respondent not to support the proposal of equalising incentives. They express strong concerns that such a move would lead to unintended and perverse consequences that would not be in the interests of customers or the long-term health of the networks. They suggest that adding a certain percentage of costs to the RAV would result in the RAV becoming detached from the actual level of investment and would drive DNOs to reduce capital programmes to the minimum necessary to meet their statutory obligations.

Proposed approach to equalising incentives

Overview

9.11. Our proposed methodology is to pursue an approach that is very similar to the second of the options set out in the December consultation. This would treat all network investment, network operating costs and closely associated indirect costs in the same way by capitalising a fixed percentage of costs across all these activities into the Regulatory Asset Value. Business support costs would be expensed separately and would face stronger incentives than the network costs. In making this adjustment we propose to capitalise around the same proportion of total costs as occurred during DPCR4 - this is designed to help ensure that the RAV is not distorted by the change and so that financeability issues are not created by the change in approach.

9.12. We believe that this approach meets our objectives in this area which are to:

- ensure that economic trade-offs are not distorted between capex and opex solutions,
- ensure that DNOs are not discouraged from applying non-network solutions which are compatible with tackling climate change, such as contracting with DG and DSM,
- avoid incentives for reclassifying costs (boundary issues),

- provide strong incentives for DNOs to keep business support costs to an efficient level, and

- simplify the current RAV rules.

Cost incentives to be equalised

9.13. The table below sets out the cost over which we intend to equalise incentives. We believe that equalising incentives over these costs removes most of the current boundary issues and the distortions to economic trade-offs between types of expenditure. The table also distinguishes between the costs entering the IQI and those that are completely separate from it. The reasoning for the distinction between costs in and out of the IQI is set out the IQI section later in this chapter.

Table 9.1 - Costs to face equalised incentives

	Costs facing equalised incentives	**Costs not facing equalised incentives**
Costs within the IQI	Load related investment (including shared-asset connections expenditure)	None
	Asset replacement investment	
	Flooding expenditure	
	Quality of service expenditure	
	Network operating costs	
	Indirects driven by both network investment and network operating costs	
	Network investment driven indirects	
	Non-relevant DG expenditure	
	Sub-station electricity	
	Island generation	
	Wayleaves	
	Underwater cables	
Costs outside the IQI	HILP investment	Relevant DG expenditure
	BT 21st Century expenditure	Business support costs
	Discretionary investment	Sole-use connections expenditure
	TMA costs	Pensions

9.14. Business support costs are defined to include the following elements: CEO costs, finance and regulation, HR, network policy, property, information systems (IS), and insurance. Indirects driven by network investment and network operating costs include the following activities: engineering management and clerical support

(EMCS), mapping, control centre, call centre, stores, health and safety. Investment driven indirects include project management and network design.

9.15. The treatment of pension costs is still under review and will depend on the outcome of other work that is currently in progress. Relevant DG expenditure and sole-use connections expenditure are excluded services that will sit outside the price control.

9.16. There are some costs, such as HILP, that we have currently placed outside the IQI but will still be subject to the same equalised incentive rate. This is because there are still a number of outstanding issues with these items - such as government policy - that affect both the DNO forecasts and our baselines. If these matters reach a conclusion soon then they may be included within the IQI. The application of the equalised incentive rate to these items of expenditure is designed to remove any potential boundary issues and distortion of incentives.

The "speed" of revenue recovery

9.17. Revenues during DPCR4 have been funded by a combination of “fast money”, where revenues are matched to the year of expenditure and “slow money”, where costs are added to the RAV and revenues allow recovery of the costs over time (currently 20 years) together with the cost of financing this expenditure in the interim.

9.18. We do not propose to materially alter this balance between "fast" and "slow" revenues. This means that the "RAV additions percentage" applying to network costs will be set to ensure that a similar proportion of costs is expected to be capitalised during DPCR5 as occurred during DPCR4. The network costs that are not capitalised will be funded as "fast money", i.e. in the year of expenditure. Business support costs will also entirely be funded in the year of expenditure.

9.19. Our proposal for the proportion of network-related costs to be added to the RAV will be set out in Initial Proposals as our modelling is refined, however, current indications are that it will be around 80 per cent. This will result in a similar proportion of network costs being added to RAV as in DPCR4. Bearing this in mind, we do not envisage significant changes to the depreciation rate except for the Scottish DNOs where we will address the reduction in revenues arising from the exhaustion of the vesting RAV.

Information quality incentive (IQI)

Overview

Background

9.20. 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.

9.21. 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.

9.22. Responses to our consultation documents and other papers suggested that this apparent "overbidding" or conservatism by DNOs may be due to risk aversion by the management of DNOs. Risk aversion implies that DNOs were consciously submitting forecasts greater than their expected level of expenditure with the expectation of gaining a lower return in exchange for receiving insurance through a weaker incentive strength, meaning they were less exposed to any under- and over-spends. A number of interested parties submitted alternative IQI mechanisms that aimed to address this risk aversion issue.

9.23. The December consultation also placed limits on the ability of DNOs to rebid following 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 which might be considered as attempts at gaming.

Summary of responses to the December Policy Paper

9.24. No responses suggested Ofgem should abandon the use of an IQI and many put forward their own ideas on how it should be refined.

9.25. Opinion was split on whether rebidding by DNOs should be allowed as part of the IQI process. CE see the inability of DNOs to change forecasts without agreement as a useful step forward. National Grid agrees that changes in forecasts after Initial Proposals should be restricted to material and explainable reasons. EDFE, ENW and SP do not share this view: they suggest that the incentives of the scheme may be destroyed as their initial bids were made without knowledge of how the IQI would be formulated.

9.26. There was also a range of views on whether perceived risk aversion needed to be addressed. CE would prefer an IQI that gave greater rewards to more challenging forecasts and discouraged risk aversion. CN also see risk aversion as an issue that prevents DNOs submitting more challenging forecasts and have submitted proposals in a CEPA paper aimed at addressing this issue. Centrica (who were also advised by CEPA) have a similar viewpoint. ENW take a slightly different approach and suggest that risk aversion can be resolved by an asymmetric mechanism that protects DNOs against cost overruns. SP disagree that the IQI is distorted by risk aversion and state that no evidence has been published that demonstrates the assertions made by other parties.

Outline of our current thinking

9.27. 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, we consider that a number of changes are needed to develop the mechanism.

9.28. To deliver equalised incentives across all network costs we have decided to widen the scope of the IQI to include network operating costs and closely associated indirect costs which were outside the scope of the IQI at DPCR4. This widening of scope is necessary in order to equalise incentives whilst preserving the incentive compatibility of the IQI. If we had left network operating costs outside the IQI, and then applied the incentive rate from the IQI to these costs then DNOs would take into account any expected under- or overspend in operating costs when submitting their capex forecasts for the IQI. A DNO that expected to overspend against our allowance for network operating costs would have an incentive to inflate its IQI forecast so that the over-spend faced a weaker incentive strength. This issue applies to the costs such as HILP which face the equalised incentive but do not enter the IQI. These costs form a small proportion of the total so we expect any distortion on incentives to be minor.

9.29. We maintain our stance on rebidding in order to minimise the scope for gaming: rebidding will only be allowed if it is justified by new information or changing circumstances.

9.30. We do not propose to implement a more complicated alternative IQI mechanism, such as those that have been proposed to address risk aversion. The reasons for this are set out in paragraphs 9.46 to 9.49 below.

9.31. In order to remove some of the risk from the IQI and partly address the issue of risk aversion - we are considering a number of other mechanisms to manage uncertainty:

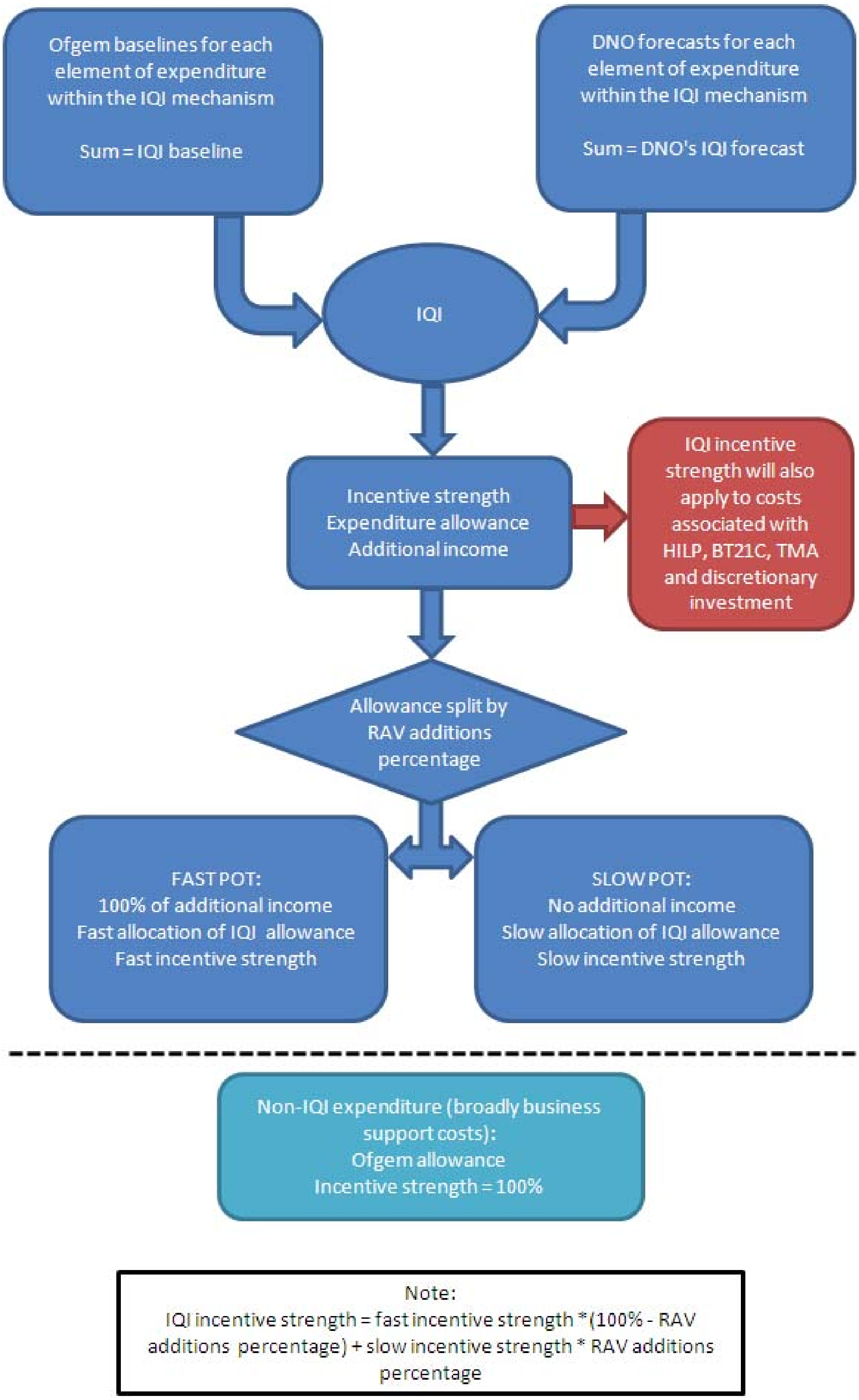
- A mechanism to manage materials input price uncertainty.
- Drivers for connections capex and general reinforcement.

- A more general price control reopener similar to that currently in place for Ofwat (IDOKs).

9.32. We also plan to remove real price effects (RPEs) from the IQI. The baselines and forecasts will be set in current prices so that different RPE assumptions do not distort the IQI. The outputs from the IQI will then be adjusted to reflect Ofgem's input price assumptions and these will then be indexed by RPI and any indexation of input prices that we introduce.

9.33. The figure below summarises our proposed approach for the IQI and equalising incentives. Further details of the mechanics of the IQI are set out in the sections below.

Figure 9.2 - Summary of approach to IQI and equalising incentives



The mechanics of an enlarged IQI

Costs to be included

9.34. The IQI must apply to the same costs which face an equalised incentive in order to both equalise incentives and maintain the IQI's incentive compatibility. This means that the IQI baselines and DNO forecasts will relate to all direct network activities including network investment, network operating costs and closely associated indirect costs. The remainder - business support costs - will not be included in the IQI mechanism.

9.35. There are a few specific areas where the associated expenditure will not be included within the IQI. These include: DG, discretionary investment, HILP, and BT 21st Century costs. These are areas where there are still significant issues which affect both the DNO forecasts and our baselines. The outstanding issues include conclusions on policy towards innovation, government policy on HILP and BT's approach to providing leased line services to DNOs under BT 21st Century. If these matters reach a conclusion soon then they may be included within the IQI. Expenditure in these areas will be subject to same incentives as IQI expenditure i.e. the same incentive strength will apply and the same proportion will be capitalised to the RAV.

9.36. DG costs are subject to a separate incentive and we propose to treat sole-use connections expenditure as excluded services that are separate from the main price control.

The strength of incentives

9.37. Our current thinking is that the incentive rate from the IQI does not need to change significantly from the strengths seen at DPCR4 which were in the 30-40 per cent range. We see this strength as being sufficient to drive the efficiencies needed by customers without placing undue risk on DNOs that might affect the risks DNOs face and impact on the cost of capital. Another consideration affecting the choice of output measures is the inclusion of output measures in the DPCR5 settlement which is discussed further in the section below.

9.38. We do not propose to pass all IQI-qualifying expenditure through the RAV, as set out in the equalising incentives section above. Instead we propose to split the amounts resulting from the IQI between what we described above as "fast" and "slow" money. The part treated as "slow money" - revenues recovered through depreciation and a return on the RAV - would be determined by the IQI expenditure allowance multiplied by the "RAV additions percentage". The "fast money" allowance from the IQI - revenues matched to the year of expenditure - would be the remainder of the IQI allowance. Any additional income from the IQI would also be treated as "fast money" and spread out over the price control period.

9.39. The incentive strength from the IQI, which must apply to the total IQI allowance, can be broken down into a "fast" and "slow" incentive rate providing that the weighted average of the two gives the overall IQI incentive strength. This would for instance allow the "fast money" from the IQI to face a 100 per cent incentive strength in the same way as the current opex allowance. This would result in the continuation of the DPCR4 methods for dealing with any under- and over-spends without the need to develop any new mechanisms.

9.40. Our Final Proposals in this area will be set out in the July Initial Proposals document.

9.41. Business support costs, which we do not propose to include in the IQI, will be treated in the same way as opex in DPCR4, i.e. there will be no adjustment for any under- and over-spends. We think that this effective 100 per cent incentive strength is appropriate for these costs as:

- They are the costs with the weakest connection to maintaining a distribution network and as such offer little direct benefit to customers. The application of a strong incentive strength to these costs helps to ensure that they are minimised.
- There is a concern that if a weaker incentive strength were applied to these costs then there might be an incentive for DNOs that are part of a larger group to allocate such costs to the distribution business so that they are partly funded by distribution customers.

Interaction with output measures

9.42. The inclusion of output measures in the DPCR5 settlement will make it harder for DNOs to make short term returns by deferring investment into the next price control period at the expense of increased risk to the network. This in itself increases the degree to which the incentive strength from the enlarged IQI will bite in DPCR5.

9.43. In the December consultation we put forward a number of ideas how DNOs might be incentivised to submit robust output measures which essentially revolved around having different IQI matrices for DNOs with and without robust outputs. Two ideas that were raised included:

- Applying weaker incentive strengths to the IQI for DNOs without robust outputs so that they can benefit less from any under-spends.
- Giving less additional income to DNOs with less robust output measures.

9.44. If DNOs continue the work they have embarked upon, we are optimistic that all DNOs will be able to provide robust output measures in time for the beginning of the DPCR5 period. If some DNOs do not provide these measures then our current preference is to incentivise their provision by being much tougher in assessing the baselines of these DNOs and requiring a much greater hurdle to be cleared before we alter our baselines away from the levels implied by our own modelling. This extra toughness on baselines for these DNOs will reduce their allowances and make them face weaker incentives from the IQI so that they benefit less from any under-spends.

9.45. DNOs have made good progress on outputs as set out in the network investment sections. It is important that further comprehensive progress is made by DNOs over the next few months.

Alternative IQI implementations considered

9.46. We have considered alternative IQI implementations that include deadbands and variable marginal incentive strengths but at present do not intend to incorporate the features into our IQI mechanism.

9.47. Deadbands provide weak incentives for small deviations from the IQI forecast. It is arguably these costs that are most within the control of the DNO using their skills as asset and operation managers, and also where customers are most likely to benefit from any efficiency savings. This reasoning suggests a strong incentive rate is important for costs in this range. The inclusion of deadbands also creates issues for incentive compatibility - i.e. they may not incentivise DNOs to reveal their expected level of expenditure.

9.48. The proposals that we have seen with variable marginal incentive rates reduce the incentive rate for each increment of expenditure away from the forecast. For example, the expenditure +/- 5 per cent around the forecast might face an incentive rate of 40 per cent but the next 5 per cent increment either side of that expenditure would face an incentive rate of say 37 per cent. The proponents of such schemes argue that such implementation would discourage apparent risk aversion from DNOs and better incentivise more realistic forecasts.

9.49. We have identified weaknesses that have prevented us from adopting such an approach:

- The approach is much more complex than the current IQI mechanism. It is no longer defined by a series of equations and is instead defined manually using a very detailed matrix that must define the outcomes for every eventuality.

- The relevant incentive rates facing expenditure would not be known until the end of the price control period. This means that companies making investment decisions during the period do not know what the full financial impact will be of any expenditure. Alternatively, the matrix could be applied on each years' costs, but this would create the perverse outcome of varying incentive strengths year-on-year, which could distort DNOs' investment decisions.

IQI matrix for DPCR5

9.50. At this stage of the price control review we have not finalised our baselines that will feed into the IQI. DNOs will also be submitting their final FBPQs in June and these will update their forecasts that will go into the IQI. Until these figures have been finalised we do not know the range of ratios that the IQI matrix will be required to accommodate.

9.51. Our current preference is to use the same IQI matrix that was employed at GDPCR. This implementation is well understood and we believe it has good incentive properties. The GDPCR IQI matrix is presented in the figure below.

Figure 9.3 - The GDPCR IQI matrix

GDN:Ofgem ratio	100	105	110	115	120	125	130	135	140
Efficiency incentive	40.0%	37.5%	35.0%	32.5%	30.0%	27.5%	25.0%	22.5%	20.0%
Additional income	2.50	1.97	1.38	0.72	0.00	-0.78	-1.63	-2.53	-3.50
Allowed expenditure	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Actual expenditure									
70	14.50	13.69	12.75	11.69	10.50	9.19	7.75	6.19	4.50
80	10.50	9.94	9.25	8.44	7.50	6.44	5.25	3.94	2.50
90	6.50	6.19	5.75	5.19	4.50	3.69	2.75	1.69	0.50
100	2.50	2.44	2.25	1.94	1.50	0.94	0.25	-0.56	-1.50
105	0.50	0.56	0.50	0.31	0.00	-0.44	-1.00	-1.69	-2.50
110	-1.50	-1.31	-1.25	-1.31	-1.50	-1.81	-2.25	-2.81	-3.50
115	-3.50	-3.19	-3.00	-2.94	-3.00	-3.19	-3.50	-3.94	-4.50
120	-5.50	-5.06	-4.75	-4.56	-4.50	-4.56	-4.75	-5.06	-5.50
125	-7.50	-6.94	-6.50	-6.19	-6.00	-5.94	-6.00	-6.19	-6.50
130	-9.50	-8.81	-8.25	-7.81	-7.50	-7.31	-7.25	-7.31	-7.50
135	-11.50	-10.69	-10.00	-9.44	-9.00	-8.69	-8.50	-8.44	-8.50
140	-13.50	-12.56	-11.75	-11.06	-10.50	-10.06	-9.75	-9.56	-9.50

9.52. We will review the feasibility of implementing this matrix once the IQI baselines and forecasts have been finalised.

RAV methodology

9.53. Appendix 12 discusses the issues affecting the RAV methodology for DPCR5. It also discusses regulatory depreciation.

10. Managing uncertainty

Chapter Summary

This chapter updates our thoughts on mechanisms we might use to manage uncertainty for DPCR5 and, in particular, to make sure we attain an appropriate balance of risk between customers and shareholders in the 2010 to 2015 period.

Question 1: What balance should we adopt between mechanisms to manage specific risks (such as input price uncertainty) and a more general type of reopener to manage a wider basket of risks?
Question 2: What risks should be covered by specific mitigation mechanism, by a general type of reopener, and which should be left to the DNOs to manage?
Question 3: Are there any additional risk mitigation mechanisms that we should be considering that are not identified in this chapter?

Uncertainty in DPCR5

Background

10.1. In setting DPCR5 revenues, we face a number of significant uncertainties. First, there is the uncertainty regarding the role of networks in a future energy industry that may be reshaped by measures to reduce CO2 emissions to tackle climate change. 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, microgeneration and electric vehicles.

10.2. Second, there is the potential scale of outturn variations in costs from the assumptions used in setting the price control. 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.

10.3. 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. Any material differences between the price control assumptions and outturn could result in either windfall gains or losses. Neither are desirable - in the former case, a windfall in one area of the price control can dampen efficiency incentives in other areas, while in the latter case, it is possible that DNOs might have insufficient revenue to finance their activities. To the extent that we include specific mechanisms to mitigate DNOs' risks for DPCR5 then this should be reflected in the cost of capital that is used in the settlement.

10.4. We recognised in our December consultation that uncertainty was going to be a significant issue for DPCR5 and macroeconomic events since then have reinforced the importance of the issue. The section below discusses the options that we raised in the December Policy Paper for managing these risks.

Options raised in the December consultation

10.5. The December paper identified a number of tools that could be used to share risks between companies and their customers within a price control settlement. It also set out our criteria for deciding which of the options identified is appropriate for each type of costs. The relevant criteria identified were as follows:

- 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.
- 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?
- 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.

10.6. We also set our initial thoughts of how the major components of the price control would be treated and these are reproduced in the table below.

Table 10.1 - Views on risk-sharing from the December Policy Paper

Component	DPCR4 treatment	DPCR5 initial views
Controllable opex	Part-capitalised - this element subject to capex incentive, rest ex ante only	Totex approach - sharing factor
ESQCR/TMA costs	Specific re-opener	Totex approach - sharing factor
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
Network investment	Subject to capex incentive	Totex approach - sharing factor
Materials costs	No index	Considering index
Customer numbers	Revenue volume driver	Possible conx capex driver (new customers only)
Units distributed	Revenue volume driver	Capex driver for general reinforcement -only where increased demand requires it
Corporation tax costs	ex ante assessment	Possible sharing factors for legislative changes
Financing costs	ex ante assessment	Possible triggers for cost of debt

Responses to the December consultation

10.7. We received a number of responses to the December paper on our approach to managing uncertainty. These are discussed in more detail in chapter 9 which discusses the responses we received about the information quality incentive (IQI) and in the sections below on input price and volume uncertainty. We provide a brief summary here:

- Some respondents proposed more complex versions of the IQI mechanism which they argued could be used to manage uncertainty.
- Concerns were raised that if we introduced a large number of mechanisms to manage uncertainty, this would make the price control settlement more complex and opaque, and also could lead to excessive and unpredictable price volatility for customers.
- There was broad support from DNOs for the use of triggers to identify large changes in input prices beyond which some form of indexation would apply.
- Respondents generally supported the development of network investment drivers, with separate drivers developed for new connections and general reinforcement and triggers for large uncertain schemes.

Overview of our current thinking

10.8. The responses to the December consultation have assisted us in developing our approach in this area. Before setting out how our approach has developed, we think it is important to make a few key points:

- There is still much debate ahead about which tools will be implemented for DPCR5. We have not made any firm decisions yet and may discount some options ahead of Initial Proposals.
- We see it as being very important that any mechanism provides symmetric protection so that customers - as well as DNOs - are protected from the negative side of uncertainty.
- Our decision on which mechanisms to employ for managing uncertainty will tie in with our cost of capital decision e.g. any de-risking of DNOs will be taken into account when setting the cost of capital.

10.9. We recognise the concerns about introducing excessive complexity and opaqueness into the regulatory settlement if we introduce a vast array of mechanisms to mitigate the different risks. For this reason, we are considering a limited number of symmetric mechanisms to manage uncertainty of the key risks along with a more general type of reopener mechanism that can be triggered in response to unforeseen circumstances.

10.10. This general type of reopener might work in a similar manner to the mechanism employed by Ofwat for interim determinations which are known as IDOKs. These interim determinations are restricted to dealing with the impact of relevant items which include relevant changes of circumstance and notified items. Relevant changes of circumstance include changes to the legal requirements in which the companies operate, and failure to deliver an output for which funding was provided at the previous price review. An interim review is triggered if the impact of the relevant items is greater than 10 per cent of revenue. Ofwat emphasises the restricted nature of the process and points out that IDoKs are not designed to be mini price reviews.

10.11. We also consider that the impact of any risk mitigation mechanisms on the volatility and predictability of allowed revenues (and hence DUoS charges for retailers and end customers) is a very important factor. We see merit in using a logging up approach to minimise this volatility subject to successful stress-testing in our financial modelling. Whilst this would still lead ultimately to adjustments to allowed revenue, a logging up approach takes place in the context of a new price control when there is typically a step change in allowed revenues in any case, and we can track indicative adjustments through the DPCR5 period in our annual price control reporting.

10.12. There are a number of areas where we have advanced our thinking since December as follows:

- IQI - we have had extensive discussions with DNOs on whether a more complicated IQI mechanism could be used as a key tool for managing uncertainty. The use of such mechanisms might remove the need for other mechanisms as it could potentially offer protection for the costs covered by the IQI. We have decided not to implement such a mechanism for the reasons set out in chapter 9.

- Network operating costs and closely related indirects - as part of our approach to equalising incentives we plan to include these costs within the IQI. This will mean that the exposure to any under- and over-spends will be shared between the DNOs and customers.

- Input price uncertainty - we have commissioned advice from CEPA on this topic and their recommendation is that a mechanism is only required to address the risk associated with the cost of materials such as copper. This issue is discussed further in the next section.

- Capex drivers - we are currently considering whether to include drivers for connections and general reinforcement expenditure. This is discussed further in the next section.

- Corporation tax - we are minded to introduce a tax trigger mechanism to mitigate risk in the event of changes to UK tax legislation, particularly in relation to corporation tax rates and capital allowances. This is discussed further in chapter 11 which discusses our tax methodology.

10.13. We are still considering our approach for pensions and will consult on this separately at a later date. We are also currently considering triggers for the cost of debt and will set out our approach in this area at Initial Proposals.

10.14. Our thinking is still evolving and ahead of Initial Proposals in July we will be considering:

- The level of risk that DNOs should face during DPCR5 compared to the DPCR4 settlement. This might be an important issue for DPCR5 if the difficulties in financial markets continue and increase the cost of raising additional capital.

- Our response to the climate change agenda. For example, we could alter the DNOs' portfolio of risk to encourage innovation in new areas that might help meet environmental objectives.

10.15. In forming our proposals in this area we will decide our approach to managing uncertainty and the balance between a general reopener and more specific risk mitigation mechanisms together with our decision on the cost of capital.

10.16. We set out in the section below further details of our thoughts towards input price and volume uncertainty.

Input price and volume uncertainty

Input price uncertainty

Background

10.17. DNOs have indicated that increases in real input prices have increased capex spend by up to 20 per cent in DPCR4. However, since the middle of 2008 there have been 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 £3,000 per tonne.

10.18. In principle, for DPCR4 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, the introduction of output measures for DPCR5 may limit the scope for DNOs to manage input price risk in this way.

10.19. 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.

Summary of responses to the December policy consultation

10.20. There appears to be general support from many DNOs for the use of triggers to identify large changes in input prices beyond which some form of indexation would apply. CE, EDFE, ENW, SP, SSE and WPD all expressed support for the use of triggers in some form. CN by contrast believe that there are significant practical difficulties to overcome in setting trigger and index levels, and suggest that input price risk is best managed through a modified IQI mechanism.

10.21. SP and SSE both prefer mechanisms where triggers would be set and indexation would apply beyond them. WPD believe that it would be impractical to implement an input price index and instead prefer an ex ante approach combined with a trigger mechanism that is only used if a DNO can demonstrate that costs have risen significantly above the assumptions for DPCR5.

10.22. EDFE and ENW identify Ofgem's proposals for the use of output measures as a constraint on the ability of DNOs to defer capex which they say increases the importance of Ofgem's approach in this area. EDFE in particular express concern if DNOs were not permitted to defer work out of high cost periods.

10.23. Centrica express concern about proposals for mitigating individual risks that would shift risk to customers which they believe would increase complexity and potentially volatility in the charges they face. Their preference is that only a small number of specific risks should have their own mitigation, the remainder (including input price risk) should be captured through a well defined and explicit general reopener. They also state a preference that any risk instrument implemented should incorporate logging up to shift price volatility to the next price control period.

Research commissioned by Ofgem

10.24. Since the December consultation Ofgem has commissioned research from CEPA on mechanisms that could be used to incorporate the indexation of real input prices into the DPCR5 settlement.

10.25. CEPA identify the following three stage process for deciding whether to offer additional risk mitigation for input prices to DNOs:

- Is the cost controllable/predictable/material?
- What form of risk mitigation would be appropriate?
- What detailed design of mechanism is appropriate?

10.26. Their analysis suggests that most of the cost items faced by DNOs do not meet the first criterion and therefore do not warrant additional risk mitigation. However, they identify the cost of materials as being uncontrollable, unpredictable and material - especially when specific input prices such as steel and copper are considered. On this basis they consider the following possible approaches for providing additional risk mitigation:

- Insurance - which could be provided through headroom or hedging.

- Indexation or a trigger - which could vary from full cost pass-through to a trigger mechanism that either leads to a re-opener or an automatic adjustment to revenues.

10.27. The report finds that indexation is likely to impose the lowest transaction cost while providing the protection against uncertainty.

10.28. The report then considers potential indexation mechanisms for the price of copper, the price of steel, and a BEAMA electrical equipment price index. CEPA recommend applying indexation to the specific price indices for copper and steel prices rather than the more general BEAMA index as they deem that the benefits of focusing on the purely uncontrollable items implied by these indices outweigh the costs associated with the complexity of targeting two indices at the relevant proportions of costs. The report also recommends using two mechanisms - one for the price of copper and one for the price of steel - to allow the mechanisms to be tailored to each individual input.

10.29. The report's final recommendation in this area is that any adjustments to revenues are carried out through a logging-up system that takes effect at the next price control so that customers do not face increased price volatility within the price control period.

Our current thinking

10.30. We are still considering including a mechanism whereby we 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 a form of indexation for the protection of both customers and shareholders.

10.31. In line with our consultants' advice we believe that any such mechanism should be limited to provide protection against materials input prices. We have not decided whether the indexation would be best targeted at specific indices such as those for steel and copper prices or at a more general index such as the BEAMA index.

10.32. We will be reviewing the different options for how a mechanism could be designed and will set out further views in the July Initial Proposals document. We would welcome views on the most appropriate method to provide protection against materials input price risks.

10.33. It is still our intention that the Information Quality Incentive (IQI) mechanism will exclude the impacts of real price effects (RPEs). The baselines and forecasts will be set in 2007-08 prices so that different RPE assumptions do not distort the IQI.

10.34. The allowed revenue would then be indexed by:

- RPI inflation in the same way that price controls are normally set relative to the RPI.
- Any other driver or indexation mechanism that we decide to introduce. For example, indexation of copper prices would mean that the fast and slow allowances would be indexed by the joint effects of changes in copper prices and the proportion of IQI expenditure that is made up by copper.

Volume uncertainty

Background

10.35. The volume of network investment in areas such as connections for DPCR5 will be significantly influenced by macroeconomic performance over the period. To a lesser degree, general reinforcement will be similarly influenced. The depth and the length of the recession are very unclear meaning that the level of network investment required for DPCR5 is also uncertain. The December Policy Paper identified a number of ways that this uncertainty can be managed within the price control.

10.36. The DPCR4 settlement includes revenue drivers based on units distributed and customer numbers to manage uncertainty in demand and new connections. As set out in the December consultation, we do not believe that these drivers capture the relationship between the investment needs of the DNOs and the volume of outputs that they must deliver. We also raised concerns that the units distributed driver may discourage DNOs from using demand side management (DSM) schemes to defer reinforcement where it is efficient to do so. We proposed to remove these drivers for DPCR5.

10.37. DPCR4 and transmission price control review (TPCR) both introduced capex drivers to deal with volume uncertainty, including uncertainty surrounding the levels of generation connection during the period. The December consultation stated our intention to extend the use of capex drivers to demand related investment and associated indirect costs where we identify significant uncertainty.

10.38. The sections below provide a summary of the responses that we received on this issue and our current thinking.

Summary of responses to the December Policy Paper

10.39. The respondents generally agreed that the current revenue driver mechanism based on units distributed is not appropriate from an environmental perspective and is not the most suitable driver for network capacity requirements. They generally supported the development of network investment drivers, with separate drivers developed for new connections and general reinforcement and triggers for large, uncertain schemes.

10.40. One DNO thought that Ofgem’s proposal to flex reinforcement expenditure based on demand at highly loaded substations would not work and risked introducing perverse incentives, with DNOs potentially losing money for reinforcing their networks and transferring load. They suggested a revenue adjustment based on either aggregate maximum demand or aggregate of maximum demand increases.

10.41. One respondent considered that risks are best considered holistically and not in smaller component parts. They considered that breaking down costs and associated risks, increases price control complexity and possibly volatility and passes risks from the DNOs to suppliers and customers.

10.42. Several DNOs emphasised the importance of considering the interaction between IQI and any revenue driver(s) introduced, and suggested possible ways as to how a revenue driver could be interfaced with IQI.

10.43. One DNO suggested that a re-opener mechanism (as used for ESQCR in DPCR4) be retained for changes to legislation that lead to material changes in costs that DNOs face.

Our current thinking

10.44. This section describes how our thinking has progressed since December. As stated earlier in this chapter, in developing our proposals in this area we will conider the balance between different available risk mitigation tools in a holistic manner along with deciding the cost of capital.

10.45. The two main areas where we are considering risk mitigation mechanisms are for connections network investment and for general reinforcement investment.

10.46. We have advanced our thinking on the price control connections network investment. Further details will be set out in Initial Proposals. We plan to adopt a different approach for sole-use assets and shared-use assets as follows:

- Sole-use assets - expenditure on these assets will be treated outside of the main control as an excluded service. Expenditure on these assets will essentially be recovered at cost with the possibility of a margin where the work is contestable. This manages the uncertainty associated with this expenditure.
- Shared-use assets - net expenditure on these assets will remain within the main price control. We will set a baseline for these costs and they will be subject to an incentive strength set by the IQI.
    - For high-volume low-cost work we are considering whether to use the number of connections involving shared asset work or some other appropriate measure as a driver to flex allowances around our baseline assumptions.
    - For higher-cost low-volume work we are considering introducing some kind of flexibility mechanism that would apply beyond a trigger point. This would be the same mechanism that would be applied to general reinforcement work and is discussed further below.

10.47. We have also made some progress on our approach to managing the uncertainty associated with general reinforcement as follows:

- Our discussions with DNOs have revealed that they are factoring in current forecasts for the recession and GDP growth into their business plans. DNOs are comfortable with managing the risk in a band around these forecasts but would like a mechanism to help them manage risk outside of this band.

- We recognise these concerns and had outlined in the December paper that we were thinking about employing some form of risk mitigation in this area. We are currently considering two options:

  - Setting an ex ante allowance with a trigger mechanism that would initiate a review of these costs - this review might be a reopener with logging up. We see this as being as more of a qualitative than a quantitative-mechanistic approach. If we decide to employ a risk mitigation mechanism in this area, this is the option we are favouring at present.

  - Employing a much more mechanistic capex driver. For example, we might set an ex ante allowance and expose DNOs to volume risk up to a trigger point beyond which a capex driver would be used to flex allowances in this area.

11. Tax methodology

Chapter summary

This chapter covers our proposed methodologies for the treatment of taxation, including the introduction of a tax trigger. In developing our policies in this area, we have taken 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. It is our 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: Is the approach to modelling DNOs capital allowances on a common basis representative of the industry position and does it ensure that no individual DNO is materially advantaged or disadvantaged by this methodology?
Question 2: Views are invited on whether the most appropriate option for the tax treatment of re-openers is the case-by-case approach.
Question 3: Should the DNOs retain the risk and rewards for all amounts below/above the trigger threshold; or for the entire amount rather than the excess over the materiality trigger; and what should be the appropriate timing of adjusting DUoS revenues following both single and multiple trigger events?
Question 4: We invite views on the practicality of communicating the likelihood of a trigger being activated and the methodology for it.

Tax methodology

Overall approach

11.1. We confirm that we are maintaining our approach for setting tax cost allowances on an ex-ante basis with an ex-post adjustment where actual levels of gearing exceed the gearing assumption underpinning our cost of capital assessment. We consulted on the merits of introducing a tax trigger mechanism to mitigate DNOs risk in the event of changes to UK tax legislation, which are outside their control, principally in corporation tax rates and capital allowances. We are minded to introduce such a mechanism, which will mitigate uncertainty. Under this revised methodology, DNOs remain responsible for managing tax risk but are de-risked from material changes outside their control and, for the duration of each review period, will not retain the whole benefit of any tax cuts or bear the extra burden of tax rises above the trigger.

11.2. A full taxation methodology statement is set out in appendix 4. That deals in detail with our approach to modelling taxation and discusses the issues surrounding the tax trigger mechanism. This chapter covers the general principles, our approach to modelling capital allowances and the tax trigger mechanism.

11.3. We will maintain our policy of applying the UK standard tax rules that have passed into legislation at the time of the Final Proposals.

Modelling of capital allowances

11.4. In previous consultations, 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 and in their view did not adequately replicate their tax liabilities to their detriment. For DPCR5 we have considered three distinct options for the allocation of expenditure into the various capital allowance 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 moderated with our view of where capex should go according to the standard tax rules, and
- The specific approach, which uses the actual DNO-specific tax pool allocation policy.

11.5. We have reviewed our approach following discussions with DNOs and are minded to revise our methodology to follow, where practical, the common treatment to attributions followed by DNOs moderated by our interpretation where there are significant discrepancies in treatment, for which we are still seeking explanations. Most DNOs were party to an agreement with HMRC, which in effect created a separate “deferred revenue” capital allowance pool for defined replacement and fault costs. However, two DNOs were not party to that agreement and they do not allocate any expenditure to this pool. By applying the common approach, we consider that this should result in the DPCR5 allocations being closer to the DNOs’ own treatment but on an industry normalised basis. Applying a common approach has merit in that it aligns the tax treatment of all DNOs’ cost categories (as defined in the FBPQ) and follows our consistent approach (in the financial model) of applying the same treatment to each element of costs making up the overall revenue allowance, e.g. WACC, debt, across licensees, pensions.

11.6. Based on our current analysis of data, which is still under review and liable to change, we propose using the following attribution basis of the key building blocks to the capital allowances pools:

Table 11.1 – Cost allocation to capital allowance pools

	General pool	Longlife	IBA	Deferred Revenue	Revenue	Non-Qualifying
DNOs party to non-load agreement						
Load Related	0.5%	91.8%	2.9%	2.1%	0.0%	2.7%
Non-Load Related	4.7%	39.8%	3.5%	52.0%	0.0%	0.0%
Other Network operating costs (inc I&M)	0.0%	0.2%	0.0%	6.8%	93.0%	0.0%
Fault repairs and restoration	0.0%	0.0%	0.0%	65.0%	35.0%	0.0%
Tree cutting	0.0%	10.0%	0.0%	11.0%	79.0%	0.0%
Non Operational Capex	89.2%	2.0%	3.1%	0.1%	0.0%	5.5%
DNOs not party to non-load agreement						
Load Related	0.0%	98.3%	1.7%	0.0%	0.0%	0.0%
Non-Load Related	5.0%	88.9%	6.1%	0.0%	0.0%	0.0%
Other Network operating costs (inc I&M)	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Fault repairs and restoration	0.0%	77.5%	0.0%	0.0%	22.5%	0.0%
Tree cutting	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Non Operational Capex	78.1%	0.0%	0.0%	0.0%	0.0%	21.9%

Capitalised indirect costs

11.7. In DPCR4, the RAV rules were applied as a proxy to attribute capitalised overheads to capital allowance pools. This treatment did not properly reflect DNOs own treatment and hence their tax allowances. For DPCR5 we propose to apply individual DNOs capitalisation treatment of indirect costs.

Tax Trigger

Background

11.8. In the initial consultation document and subsequent Policy Paper, we sought views on the merits of introducing a tax sharing or a trigger mechanism. This would be tied to specific changes in the tax regime and legislation that are outside the control of DNOs leading to a re-opener or an ex post adjustment.

11.9. The main criterion for deciding for or against a trigger is the extent to which we consider DNOs should be exposed to this risk. Expectations regarding the future direction of short-term movements in the rate of corporation tax are not a factor in assessing the merits of a trigger. Initially, respondents expressed mixed views but in their responses to the Policy Paper, there is now general but not unanimous agreement (including suppliers) that a trigger mechanism is appropriate. The mechanism should be symmetrical and potentially remove the risk and upside from the DNOs subject to a materiality threshold. In effect, the downside risk of adverse legislative changes should be removed from the DNOs whilst similarly the customer should retain the upside benefit of beneficial legislative changes. DNOs accept that this would happen in competitive markets in response to generic changes to tax. Consumers may also benefit from the fact that the reduced risk on DNOs may be a factor in considering the appropriate cost of capital. 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. We estimate this gain to be equivalent to a 60 basis point increase for each year of the DPCR4 period in the return on regulatory equity.

11.10. A secondary objective of introducing a trigger is that it should contribute towards our objective of ensuring the financeability of DNOs over the price control period in the event of material adverse changes to their tax burden.

Proposal

11.11. Having considered the options, we are proposing a symmetric sharing mechanism, subject to a trigger that activates once an explicit materiality threshold is reached to avoid adjusting for relatively small changes. It should also be measurable by us. The mechanism still incentivises the DNOs to continue to manage their tax affairs efficiently within the existing tax regime.

11.12. Our view is that any trigger would be restricted to specific legislative changes, i.e. to the rate of corporation tax applicable to large companies or to the rate(s) of tax relief for capital expenditure. These legislative changes must be both transparent and measurable by us. In their responses, DNOs have suggested that the definition of legislative changes should be widened beyond changes in the relevant legislation. Our current position is that we do not agree as this may add unnecessary complexity and relates to changes which are not necessarily measurable by us. Our reasons are explained in appendix 14. We will review with DNOs under what conditions some of their other proposals can satisfy the transparent and measurable by us criteria.

11.13. The trigger will be calculated by re-running the DPCR5 financial model. We will assess the impact on the tax allowance component of revenues on the basis of the average annual effect over the remainder of the price control period of changes in the relevant legislation. Relevant changes could be introduced in a Finance Act, other Act of Parliament, Statutory Instrument or other legislative instrument. The methodology is set out in appendix 14.

11.14. In practice, it is expected the trigger to be activated mainly from changes in the main rate of corporation tax or changes to the rates of capital allowances, or the allowability of expenditure as tax deductible.

Timing of revised revenues

11.15. In addition to setting an appropriate trigger, we also need to balance the impact on consumers (and suppliers) of the timing of implementing revised revenues, so that suppliers with customers on fixed or capped contracts are not adversely affected; and, where the changes are material, the affect on DNOs financeability. Suppliers prefer a position of stability in their costs (DUoS charges) which are, at least, predictable. Suppliers may be adversely affected if their costs were raised without them being able to recover such cost increases from their customers who are on fixed tariffs. Conversely, suppliers' customers should benefit from any reduction in suppliers costs without an unduly long delay.

11.16. In balancing the need to avoid year-on-year volatility in charges and to protect consumers, it is considered that there should be a delay between the trigger being activated and the implementation of revised revenues. However, any delay should not adversely affect DNOs financeability or one of the reasons for the trigger is defeated. The delay period could be longer dependent on the point in the price control period in which the trigger is activated and its magnitude. There are a number of options, which are set out in appendix 14.

11.17. The use of re-openers, such as the tax trigger place an onus on DNOs to communicate the likelihood of these being triggered and the materiality to key stakeholders. We are considering introducing requirements to both notify (and quantify insofar as practical) these to both key stakeholders and us in the licence. We invite views on the practicality of communicating the likelihood of a trigger being activated and the methodology for it.

Appendices

Index

Index – supplementary questions

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 5 June 2009 and should be sent to:

DPCR5 Response
Electricity Distribution

Ofgem
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, SW1P 3GE
020 7901 7036
nicola.cocks@ofgem.gov.uk

Chapter 2: Overview of FBPQ forecasts

Question 1: What are your views on the DNO cost forecasts presented in this chapter?

Chapter 3: Operational cost assessment methodology and results

Question 1: Have we exposed the correct costs to comparative benchmarking?
Question 2: Do you agree with the assumptions we have made for our core analysis?
Question 3: What are the appropriate cost drivers for each of the cost groupings?
Question 4: How should we determine baselines for the costs excluded from comparative benchmarking?
Question 5: How should we treat atypical costs in the price control settlement?
Question 6: What weight should we give to the benchmarking relative to other considerations?

Chapter 4: Methodology - Core network investment

Question 1: Do you agree with Ofgem's approach to assessing core network investment allowances based on the wide range of evidence detailed in the chapter?
Question 2: Do you agree with the primary network general reinforcement modelling methodology that Ofgem has adopted for DPCR5?
Question 3: Do you agree with the asset replacement modelling methodology that Ofgem has adopted for DPCR5?
Question 4: Is the outlined process for developing Initial Proposals suitable?

Chapter 5: Network investment – Environment

Question 1: Do you agree with our approach to assessing the forecasts of distributed generation, discretionary expenditure and losses and are there any other factors you think we need to take into consideration?

Chapter 6: Ongoing efficiencies and input prices

Question 1: Have we identified the most relevant unit cost and productivity measures from other sectors to help inform our ongoing efficiency assumption for DPCR5?
Question 2: When calculating these measures, which comparator sectors and time periods should we focus on?
Question 3: What weight should we give to this analysis relative to other information?
Question 4: What method should we use for setting our input price assumptions for DPCR5?

Chapter 7: Customers

Question 1: Do you agree with the proposed mechanism (in full) for worst served customers?
Question 2: Do you agree with the proposed approach (in full) for setting unplanned targets for customer interruptions and customer minutes lost?
Question 3: Do you think that we should set a cap on the cost per benefitting customers within the worst served customers mechanism and, if so, what level should this be set at?

Chapter 8: Network output measures

Question 1: Is Ofgem's proposed methodology for general reinforcement and asset replacement outputs appropriate?
Question 2: Is Ofgem's proposed approach for other areas of investment appropriate?
Question 3: What approach should be taken if a DNO fails to deliver the agreed outputs i.e. how could the incentives be adjusted?
Question 4: Do you consider that the output measures proposed provide sufficient protection in their own right, or is it appropriate to have some form of additional safety net in the DPCR5 settlement, for example through monitoring investment volumes?
Question 5: Should there be an obligation on DNOs to further develop output measures during DPCR5?
Question 6: We seek views from stakeholders on the role that outputs should play in DPCR5 and particularly how they can best be implemented and used.

Chapter 9: Cost incentives

Question 1: Do you agree with our proposed approach to equalising incentives?
Question 2: Have we identified the most appropriate costs to be within the equalised incentive and the IQI?
Question 3: How should we set the "RAV additions percentage" that will determine the split between split between "slow" and "fast" money?

Chapter 10: Managing uncertainty

Question 1: What balance should we adopt between mechanisms to manage specific risks (such as input price uncertainty) and a more general type of reopener to manage a wider basket of risks?
Question 2: What risks should be covered by specific mitigation mechanism, by a general type of reopener, and which should be left to the DNOs to manage?
Question 3: Are there any additional risk mitigation mechanisms that we should be considering that are not identified in this chapter?

Chapter 11: Tax methodology

Question 1: Is the approach to modelling DNOs capital allowances on a common basis representative of the industry position and does it ensure that no individual DNO is materially advantaged or disadvantaged by this methodology?
Question 2: Views are invited on whether the most appropriate option for the tax treatment of re-openers is the case-by-case approach.
Question 3: Should the DNOs retain the risk and rewards for all amounts below/above the trigger threshold; or for the entire amount rather than the excess over the materiality trigger; and what should be the appropriate timing of adjusting DUoS revenues following both single and multiple trigger events?
Question 4: We invite views on the practicality of communicating the likelihood of a trigger being activated and the methodology for it.

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.[20]

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[21].

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 existing and future consumers, 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[22];
- the need to contribute to the achievement of sustainable development; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[23]

[20] entitled "Gas Supply" and "Electricity Supply" respectively.
[21] 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.
[22] 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.

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[24] 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; 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[25] 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.

[23] The Authority may have regard to other descriptions of consumers.
[24] or persons authorised by exemptions to carry on any activity.
[25] Council Regulation (EC) 1/2003

Appendix 3 - Glossary

123

132 kV

Only covers assets at the 132 kV voltage level.

A

Annual Survey of Hours and Earnings (ASHE)

Data provided by the Office for National Statistics (ONS), provides information about the levels, distribution and make-up of earnings and hours paid for employees within industries, occupations and regions.

Asset replacement expenditure

Investment made to replace assets on the network where the asset has reached a condition that it is no longer fit for purpose and replacement is the most economic solution. Also includes replacement of major plant items that have failed.

Atypical Costs

The DNOs report atypical costs as part of the annual RRP submissions. These costs include certain types of severance and restructuring costs as well as other one-off costs.

B

Base case expenditure

Any expenditure that is not discretionary

Building Construction Information Service (BCIS)

Data on regional costs for construction contractors, which Ofgem used in the Gas Distribution Price Control to adjust contractor costs for Gas Distribution Networks operating within the M25 area.

Benchmarking methodology for CI and CML

In order to take into account inherent and inherited factors when comparing quality of supply, Ofgem jointly with the Quality of Service Working Group, has developed a method for calculating benchmarks for CIs and CMLs. In essence this method involves grouping physically similar parts of networks together and then comparing performance at this more disaggregated level. Overall benchmarks are then calculated for each DNO based on the number of circuits it has in each group.

Business Support Costs (BSCs)

Consists of the following activities: IT & Telecoms, Property Management, HR & Non-Operational Training, Finance and regulation and CEO etc. The definitions of these activities can be found within the DPCR5 August Forecast Business Plan Questionnaire Rules.

BT 21st century networks (BT21CN)

Proposed changes to BT's commutation network which may impact on circuits leased by the DNOs for protection signalling and substation commutation.

C

Capital Expenditure (Capex)

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

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:

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

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:

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

D

Data envelopment analysis (DEA)

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

Distributed Generation (DG)

Any generation which is connected directly into the local distribution network, as opposed to the transmissions network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported for use across the UK.

Distributed Generation Incentive (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.

Discretionary expenditure

Expenditure that is not ordinarily required for the ongoing operations of the company, but where the company can provide a business case as to why the benefits realised would justify the cost. For DPCR5 it covers alternative expenditure to that normally considered, which would enable the network to be more flexible in the future (with respect to connecting distributed generation, using demand side management or active network management etc.)

Diversions expenditure

Expenditure associated with the diversions of OHLs as the result of wayleave terminations which are not rechargeable. Also includes expenditure on the conversion of wayleaves to easements, injurious affection and related costs.

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.

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

Extra High Voltage (EHV)

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

Engineering Indirect Costs (EICs)

Consists of the following activities: Network Design, Project Management and Engineering Management & Clerical Support. The definitions of these activities can be found within the DPCR5 August Forecast Business Plan Questionnaire Rules.

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.

European Union Emission Trading Scheme (EU ETS)

The EU-wide greenhouse gas emissions trading scheme, under which governments must set emission limits for all large emitters of carbon dioxide in their country. Each installation is then allocated an allowance for the particular phase in question, with the first phase running from 2005 – 2007 and the second from 2008 – 2012. Installations may meet their cap by either reducing emissions below the cap and selling the surplus, or letting their emissions remain higher than the cap and buying allowances from other participants in the EU emissions market.

F

Fast money

Fast money is the revenue that is matched to the year of expenditure.

Fault level expenditure

Expenditure on assets where the equipment fault rating is not adequate to met system requirements.

Forecast business plan questionnaire (FBPQ)

A major information request by Ofgem in the form of excel spreadsheets and associated narrative guidance. This captures key historical information and forecast information for the remainder of DPCR4 and DPCR5. We also obtained detailed explanatory narratives from each DNO.

Feed-In Tariffs

Guaranteed prices for electricity generated using small-scale low carbon technologies up to a maximum limit of 5 megawatts (MW) capacity. The Energy Act 2008 provides broad enabling powers for the introduction of the feed-in tariffs, which will be introduced through changes to electricity distribution and supply licences.

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.

General reinforcement expenditure

Investment to reinforce the network due to changes in general demand or generation background that is not directly attributable to a specific demand or generation connection.

Gigawatt (GW)

A measure of energy equal to one thousand megawatts.

H

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

Idok

Idok is a term used in the water sector for an "interim determination of K", where K is the change in customer charges from one year to the next. It represents a partial re-opening of the price control.

Incremental losses expenditure

The incremental costs of equipment that would result in lower losses versus that included by the DNO in its network investment programme. The expected loss reduction that would be achieved from the lower loss equipment has to justify the additional expenditure.

Independent distribution network operators (IDNOs)

Any electricity distributor whose licences were granted after 1 October 2001. IDNOs do not have distribution services areas.

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 is a mechanism for setting price control allowances that provides ex ante incentives for DNOs to submit accurate forecasts of their expected expenditure and provides incentives for efficiency improvements once the price control has been set.

K

Kilowatt (KW)

A measure of energy equal to one thousand watts.

L

Legal and Safety expenditure

Investment to meet specific legal or safety requirements not addressed via normal asset replacement. For example: site security, ESQCR safety clearance, asbestos removal.

Load Indices (LI)

Proposed output metric for substation loading similar to the health index (HI) but instead of capturing asset health the LI captures the loading risk on a substation taking account of load (MVA) over firm, duration over firm and forecast load growth.

Load related expenditure (LRE)

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

Low Voltage (LV)

All voltage levels up to and including 1kV.

M

Modern Equivalent Asset Value (MEAV)

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

Megawatt (MW)

A measure of energy equal to one thousand Kilowatts.

N

National Grid Electricity Transmission (NGET)

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

Net demand customer specific expenditure

Total (gross) expenditure on new demand connections (and increases to existing connections) less capital contributions paid by the connecting party i.e. expenditure net of contributions.

Network Operating Costs (NOCs)

Consists of the activities of Faults, Inspections and Maintenance and Tree Cutting. The definitions of these activities can be found within the DPCR5 August Forecast Business Plan Questionnaire Rules.

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.

Network Support Costs (NSCs)

Consists of the following activities: Control Centre, System Mapping, Network Policy, Call centre, Stores, Vehicles & Transport, Health & Safety and Operational Training. The definitions of these activities can be found within the DPCR5 August Forecast Business Plan Questionnaire Rules.

Non-operational IT

Activities as defined in the RRP guidelines i.e. excludes IT equipment used exclusively in the real time management of network assets such as RTU units and communication equipment receivers at the control centre. Non-operational property - As defined in the RRP guidelines includes offices and depots. Substations and other operational premises are not included.

O

Ongoing efficiency improvements

Efficiency improvements in an industry can be separated into two components: a catch-up element which captures the effect of firms implementing practices already adopted by the more efficient firms, and ongoing efficiency improvements that will be made by the industry as a whole. These ongoing efficiency improvements reflect the improvements that would be expected of the most efficient firms in the industry. Ongoing efficiency improvements are sometimes known as frontier shift.

Operational IT and telecoms (excluding BT 21st century networks)

Investment in Operational IT and telecoms, such as, substation RTUs, marshalling kiosks, communications for switching & monitoring, and control centre hardware & software.

R

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.

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.

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

Slow money

Slow money is where cost costs are added to the RAV and revenues allow recovery of the costs over time (currently 20 years) together with the cost of financing this expenditure in the interim.

T

Time Fixed Effects Approach

This approach includes parameters that measure the differences in costs between years. These differences in costs will reflect a combination of factors such as changes in input prices and industry-wide improvements in efficiency.

Time Series Data Regression Technique

Time series panel data regressions are estimated using data from more than one time period. The additional data can allow better estimation of the effect of cost drivers than is possible using a single year's data.

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.

Use of system network reinforcement cost

Expenditure on the network that is required to connect DG but where the reinforcement will also be utilised by other users of the network and therefore the cost is included in the generation use of system charges rather than being borne solely by the connecting DG.

W

Weighted Average Cost of Capital (WACC)

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

Z

Zero Carbon Homes

The government's zero-carbon homes policy, set out in the Housing Green Paper, "Building a Greener Future", proposes that all new homes in England should be zero-carbon from 2016.

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:

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