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Electricity Distribution Price Control Review Initial Proposals - Allowed revenue - Cost Assessment

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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, generators, transmission owners, electricity suppliers and other interested parties.

Overview:

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

The current price control expires on 31 March 2010 and Ofgem is now undertaking a Distribution Price Control Review (DPCR5) to set the controls for 2010-2015. This document should be read in conjunction with our Distribution Price Control Review Initial Proposals core document. This supplementary document sets out in greater detail the associated incentives and obligations of DPCR5.

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Context

This document is one of three more detailed, technical documents that accompany the DPCR5 Initial Proposals consultation. These documents explain the methodologies and rationale we have applied in arriving at our Initial Proposals and set out further detail. They are targeted at the DNOs and those stakeholders who require an in depth understanding of our proposals in some or all areas. We are consulting separately on the treatment of the costs associated with defined benefit pension schemes.

Initial Proposals outlines our current view of the maximum allowed revenues each DNO should be allowed to collect from customers between 2010 and 2015. We set out the behaviours and outputs customers want and expect from the DNOs over this period and the incentives and obligations we propose to use to achieve them. We will publish Final Proposals in late November 2009. If the DNOs accept them, the new arrangements will come into effect on 1 April 2010. If they do not we will refer the matter to the Competition Commission.

In December 2008, we published our Policy Paper. The document focussed on three themes, environment, customers and networks and set out our views on the overall approach to setting the control, the methodologies we propose to use, the structure of incentives and the new regulatory arrangements we think are appropriate.

In May 2009, we published our Methodology and Initial Results document. This sets out details of our cost assessment methodology and the initial results for a number of core cost areas. We explained that we would continue to develop our work in this area as we worked towards Initial Proposals.

As we develop Final Proposals for late November 2009 we will continue to work closely with the RPI-X@20 team, who are considering our current approach to regulating GB's energy networks and developing recommendations for future policy. The RPI-X@20 team will publish its Emerging Thinking in November 2009.

Associated Documents

- Electricity distribution price control review. Initial Proposals. (92/09)
- 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)
- Electricity distribution price control review. Methodology and Initial Results Paper (47/09)
- Regulating energy networks for the future: RPI-X@20 Principles, Process and Issues (13/09)

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Summary

One of the core elements of DPCR5 is assessing the efficient level of network investment and operational costs for 2010 to 2015 enabling DNOs to deliver an appropriate level of outputs, reliability, customer service and meet all of their statutory and licence obligations. This will ensure they can maintain a secure and reliable supply at an efficient cost while ensuring that any new assets they install meet customers' needs into the future and, where possible, taking into account how those needs might change.

This document sets out in greater detail how we have arrive at our initial proposals. It covers how we have carried out the cost assessment for each of the building blocks of DNOs' costs, the results of this work and how this has then be pulled together to form an overall view of efficient level of expenditure for each DNO for 2010 to 2015. This takes into account a wider range of information including their overall performance during DPCR4, the quality of information they have provided and the robustness of their forecasts.

- **Chapter 1: Overview of the cost analysis -** This chapter sets out a brief overview of our approach to the cost assessment work for DPCR5.

- **Chapter 2: Forecast Business Plan Questionnaire (FBPQ) Information -** At the end of June we received updated cost forecasts from each of the DNOs for the period 2010 to 2015. This Chapter sets out a summary of the information for each of the building blocks including core network investment, non-core investment, operational activities and non-operational capex.

- **Chapter 3: Network Investment -** This chapter provides a summary of the key factors we have considered since the publication of the May document and how we have updated our analysis. It sets out our initial proposal baselines for each of the elements of core network investment including demand connections, asset replacement, general reinforcement, and most elements of non-core investment such as flooding, technical losses, quality of service and BT 21st Century. There are a number of specific line items where our initial proposals will be set out in a September update letter or where analysis will be updated because we have only recently received more detailed forecasts. Finally we explain the approach we have taken to ongoing capex efficiency and forecast real changes in input prices.

- **Chapter 4: Operating Activities** - This chapter sets out how we have updated our analysis of operational costs since the May document. It explains the changes we have made to the benchmarking, including our adjustments for regional factors, the weighting we have applied to different elements of the analysis and the decisions we have made in terms of benchmarking at the average, upper quartile or frontier. It also describes the approach we have adopted for costs that sit outside of the main comparative analysis and the work carried out by our consultants. We then present our initial proposals for each of the key elements of operational activities. Finally we set out our analysis for ongoing efficiency and real growth in input prices and present our results including these factors.

- **Chapter 5: Shetland and Transmission Exit Charges -** This sets out our options for the treatment of the additional costs of meeting electricity demand on Shetland and the latest information on Transmission Exit Charges

- **Chapter 6: Cost uncertainty - indexes, triggers and reopeners** - This sets out our review of the mechanisms in place for DPCR4 and our initial proposals for revised arrangements to manage cost uncertainty during DPCR5.

- **Chapter 7: Bringing it all together -** This chapter explains how we have brought together the different elements of the cost analysis to form our view of overall cost baselines for initial proposals. It explains how we have sense checked our analysis and carried out a holistic assessment of the companies' costs, taking into account a broader range of evidence. It presents Ofgem's overall initial proposals baselines for each company and the resulting cost allowances and incentive strengths per DNO once we have applied the Information Quality Incentives (IQI).

1. Overview of our approach to cost assessment

Chapter Summary

This chapter sets out an overview of our approach to the cost assessment analysis for Initial Proposals.

Question 1: Have we taken an appropriate approach to assessing costs?
Question 2: What mechanism should be used to fund high value projects?
Question 3: What assumptions do you think we should use for real price effects and ongoing efficiencies for DNOs over the 2010-15 period?
Question 4: Do you agree with our proposed methods for handling uncertainty?
Question 5: Are our proposals for volume drivers on low-cost connections involving shared assets proportionate, i.e. is the mechanism necessary?
Question 6: What is an appropriate materiality threshold for the operation of our proposed load related expenditure reopener?
Question 7: Does the GDPCR reopener for TMA costs provide a good template for our final DPCR5 proposals for these costs?

Introduction

1.1. One of the core elements of DPCR5 is assessing the efficient level of network investment and operational costs for 2010 to 2015 enabling DNOs to carry out their activities and deliver an appropriate level of outputs. This will ensure they can provide a secure and reliable supply at an efficient cost while ensuring that any new assets they install meet customers' needs into the future and, where possible, taking into account how those needs might change.

1.2. The DNOs collectively forecast £15.4bn of network expenditure during DPCR5. We have spent the last six months in discussions with each DNO on its business plans and carrying out our cost assessment. We have taken a firm but fair approach and propose to cut these forecasts by 16 per cent on average. After applying the Information Quality Incentive (IQI) mechanism which sets allowed revenues as a weighted average of the DNO bid and the Ofgem view, our proposal is that DNOs should be allowed a 13 per cent increase on expenditure in the current period. This represents a 14 per cent reduction on their forecasts.

1.3. This document sets out a detailed explanation of our approach to the cost assessment and the associated results. It also describes our proposals for addressing cost uncertainty.

Overall Approach to the cost assessment

1.4. Our overall approach to the cost assessment work has been to review the DNO forecasts, carry out our own modelling and benchmarking work, consider evidence on why the DNOs' forecast volumes or costs differ from our benchmarks and form an overall view on the appropriate baseline level of costs from DPCR5 taking this and wider evidence into account.

1.5. We present a detailed summary of each of the DNOs' historical costs and forecast costs in Chapter 2**.** This provides details of the overall forecast movements in costs between DPCR4 and the key drivers of these changes in costs.

1.6. The cost analysis has been carried out at a disaggregated level for each of the key building blocks of DNO expenditure including:

- **Network investment** which is made up of core investment such as asset replacement, general reinforcement and non-core investment such as quality of service costs, costs of flood protections and BT 21st Century. This is set out in Chapter 3.
- **Operational activity costs** which include network operating costs, closely associated indirect costs, business support costs and non-operating capex such as vehicles, IT and telecoms. This is explained in Chapter 4**.**
- The additional costs of meeting electricity demand on **Shetland** and the latest information on **Transmission Exit Charges** is explained in Chapter 5**.**

1.7. We have then pulled the results of our analysis together to form a view of the total expenditure requirements for each of the DNOs and have carried out sense checks to ensure the results of our analysis are sensible and fit well with other broader information regarding the DNOs, including:

- Information on the DNO forecasts at DPCR4 and how the DNOs have performed against these forecasts during DPCR4,
- The quality of the information they have provided during the annual cost reporting visits over the last 4 years, including the robustness of project papers and explanations they have provided,
- The robustness of the forecasts and supporting information that they have provided during the DPCR5 review, and
- The quality of output information they have provided.

1.8. This overall sense check is described in **Chapter 6**. We are applying a revised version of the Information Quality Incentive (IQI) in DPCR5 to encourage the DNOs to submit more realistic forecasts. The IQI has a number of effects. It sets the cost allowances part-way between the Ofgem baseline and DNO forecasts placing greater weight on their information than we have done in the past. The DNOs are also allowed to earn additional income depending on how close their forecast is to our baseline. Finally, the IQI sets the incentive rate for future efficiency savings dependent on how close the DNO's forecast is to our baseline. Chapter 6 also presents the resulting cost allowances and incentive strengths per DNO once we have applied the IQI.

1.9. The proposals for network expenditure set out in this document are firm and are based on comprehensive and robust analysis. We do not expect to see significant movements in our assessment of network expenditure in the run up to Final Proposals. There are a few areas of costs that we have not yet analysed or where we will update our assessment based on additional information from the DNOs. We will carry out our assessment over the coming weeks.

1.10. The areas we intend to update include:

- Demand connections (both the ex ante allowance and the baseline and unit costs for those connections subject to a volume driver),

- General reinforcement and asset replacement, in order to take account of the detailed reconciliation of the DNOs' proposed outputs and their forecast expenditure. This may result in changes to either the baseline expenditure, the level of outputs that the DNO commits to, or both,

- Our Operational cost analysis to take into account greater quality assurance on the DNOs' data submissions. The June FBPQ submissions included an additional disaggregation of data between those indirect costs that supported activities within the price control (e.g. costs supporting non-load related expenditure, connections costs subject to the apportionment rule and non-operational capex), and those outside the price control (e.g. sole use connections costs). We have run a version of our analysis using only the cost data identified as funded through the price control but have not had the opportunity to undertake our usual quality assurance work on those numbers. The results of this analysis identified inconsistencies, anomalies and differences in cost allocation across the companies.

1.11. The areas where there is insufficient clarity to make firm baseline proposals at this stage include:

- Major system risks expenditure (High Impact Low Probability (HILP) events only),
- BT 21st century expenditure,
- Expenditure on rising mains and laterals, and
- Expenditure on Critical National Infrastructure Costs (e.g. preparation for black start), and
- Costs associated with the Traffic Management Act 2004.

1.12. We will issue proposed baselines for these areas of expenditure in the autumn once there is more clarity around the requirements.

1.13. There are a number of areas where we think we need for mechanisms to address uncertainty in the volume associated with network investment. Given the current situation in the housing market and wider economic conditions it is difficult to predict the volume of demand connections over the next few years. There is also uncertainty in the number of large high-value connections and requirements for general reinforcement. We are proposing to true up the allowances for high-volume low cost connections at the end of the price control period based on the actual volume of connections. We also propose to introduce a bundled reopener for low-volume high-value connections and general reinforcement costs to ensure that there is protection for both DNOs and consumers for high materiality changes to the assumptions underpinning the price control.

1.14. Finally, there continues to be uncertainty regarding the costs associated with complying with the Traffic Management Act 2004 and the Transport (Scotland) Act 2005, although both Transport for London (TfL) and Kent Council are due to start implementing the schemes from April 2010. Given that we have no historical information regarding these costs, we propose to include a stand-alone reopener for these costs during DPCR5.

1.15. Details of our approach to cost uncertainty are set out in **Chapter 5**.

Review of network investment

Process

1.16. Our review of the DNOs' forecasts for network investment has been highly detailed and robust. We developed and improved network investment models used in previous price control reviews. For network replacement we assessed each DNO's forecasts against its own asset replacement policies in the past, and against the expenditure forecasts of other DNOs, taking into account the age profile of assets on the individual networks. Our network reinforcement model similarly assesses capacity added against the additional capacity each DNO has needed to meet demand growth in the past, and compares the forecast unit cost of adding new capacity with long run average costs. We have assessed both the volume of investment each company is planning to undertake and the unit cost of this investment.

1.17. Our work has been through several iterations. We used our models to assess the forecasts we received from the DNOs in February and to highlight areas of concern. We held detailed discussions with each of the DNOs to explain our approach, discuss our concerns and give the opportunity for the DNOs to provide us further feedback. We spent much of May and June reviewing additional information, for example asset condition data, provided by the DNOs in response to our questions. We have since incorporated the DNOs' final DPCR5 forecasts into our models to inform our view of DPCR5 expenditure. Finally, the view of network investment expenditure for each DNO set out in this document has been influenced by a number of broader considerations including the company's track record in spending against its forecasts, the ability of the company to ramp up to new levels of expenditure and the quality of the business plan narrative submitted along with the expenditure forecasts.

1.18. Throughout this process we have had support from specialist engineering consultants, PB Power. They have audited our investment models. We have also made full use of our in-house team of expert engineers and economists who have built up an understanding of each business over the past few years including through the cost visits and the reporting process we carry out annually.

1.19. The adjustments we have made to each DNO's forecast for network investment are set out below.

Key findings - asset replacement and network reinforcement

1.20. We think that in general the DNOs are looking to replace an appropriate volume of assets over the DPCR5 period, especially once the condition of the assets and their observed rate of deterioration is taken into account. In 4 cases we have made no cuts to the volumes the DNO proposes to make, with cuts of below 10 per cent in most other cases. Overall, our proposals should have only a minor impact on the volume of asset replacement that DNOs are planning to undertake, and we consider that the companies should be able to achieve their planned network health and fault levels by 2015. This is in line with the results of the stakeholder engagement and customer research which suggested that customers expected no deterioration in the networks.

1.21. As the common framework for network outputs has only been developed and agreed since the publication of the May document DNOs have only very recently provided the level of outputs they commit to deliver as part of the DPCR5 settlement. Between Initial and Final Proposals there will be a process to fully reconcile the outputs with the investment allowance for asset replacement (and general reinforcement). If DNOs are unable to adequately quantify and reconcile the outputs associated to their forecast network investment expenditure we may make further reductions to their forecasts.

1.22. We see a range of attitudes towards risk in the volume of reinforcement investment forecast by the DNOs, with some DNOs looking to build in additional capacity early in response to forecast demand growth. However, as is explained in more detail in Chapter 6 there is some uncertainty around the rate of demand growth in each DNO area and we propose to have an integrated reopener for large one-off connections and general reinforcement making use of the new load index. This reopener will be dependent on the DNO being able to demonstrate through the load index that demand is significantly higher than originally forecast. This should mean that customers do not have to pay for reinforcement unless it is necessary and that there is no risk of the DNO not being funded to provide the capacity that is required to accommodate new demand.

1.23. We think that many of the DNOs still have a conservative view of the unit costs they will face over the DPCR5 period. We have observed a very large range in the unit cost assumptions the DNOs make. Applying sensible benchmarking which allows each DNO a set of unit costs at the lower of the DNOs' forecast or the median level has allowed us to cut network investment expenditure by 11 per cent.

Exceptions

1.24. In a number of cases DNOs are proposing to undertake large investment projects in excess of £15m, which together total around £0.5bn. In particular, EDFE has proposed a series of interrelated projects to reinforce central London which together will cost £170m. We have taken these projects outside of the assessment process explained above. Our consultants have reviewed and indicated their support for the engineering justification provided by EDFE for the London projects. However, as with the other projects there is some uncertainty over whether these projects will go ahead in the DPCR5 period or whether they will be deferred by issues such as delays in gaining the relevant planning consents or by difficulties resourcing the projects. We are also concerned that our proposed output measures will not capture whether these projects have gone ahead, and we would like to make sure that customers only pay where investment has been made.

1.25. There are a number of ways in which we could treat these costs, and we seek views on whether we should:

- Provide an ex ante allowance in line with what the company has requested and conduct an ex post review to confirm whether the project went ahead and was carried out efficiently with clawback if the project wasn't carried out and/or there was inefficient spend,

- Provide an ex-ante allowance but require the DNOs to provide scheme specific output measures, or

- Provide only part of the required funding up front with an ex post adjustment to the allowances in the next price control depending on actual investment made. In this case we would set an ex-ante cap on the total amount of funding that we would allow for each project.

1.26. Ofgem's initial proposals for these allowances (as set out below) have been calculated assuming the last of the above-listed approaches to large project costs.

1.27. As part of its business plan, EDFE has requested we provide up front funding for costs associated with the Olympics. We think that, as far as possible, costs associated with the Olympics should be borne by the relevant authorities or EDFE's shareholders, and not by customers in London. For this reason our proposals make no allowance for costs related to the Olympics. In early 2010 we will consult separately on the regulatory issues raised by the 2012 Olympics.

Review of network operating and indirect costs

Overall Approach

1.28. We have generally arrived at our view of the network operating and indirect costs that the DNOs will be allowed to recover from customers by benchmarking historical cost data and then rolling forward these benchmarks in line with our view on:

- the scope for further efficiency improvements,
- movements in the DNO's real prices, and
- the impact that the volume of activity will have on cost levels over the five years.

1.29. In general, this approach means that the benchmark costs for less efficient companies will be brought in line with those that are more efficient and shareholders, not customers will carry the costs of any inefficient operations. Our benchmarking shows that there is still a considerable gap between the least and most efficient DNO, with the highest cost DNOs 35 per cent above the average industry level for network operating costs and 26 per cent above for indirects and non-operational capex. Conversely, the most efficient DNO is 41 per cent below for network operating costs and 21 per cent below for indirects. In many cases we can trace a company's level of efficiency back to corporate structure or business strategies. Overall we consider that the efficiency ranking generated by our work matches the impression that we and the companies have of relative efficiency in the industry.

1.30. We have conducted our benchmarking analysis using DNO cost data for four years (2005-06 to 2008-09), which we collected through our annual regulatory reporting process (RRP) and the latest DNO business plans. The RRP has allowed us to collect data from each DNO on a largely consistent basis. The improved data set means we have been able to conduct more sophisticated and robust benchmarking than before. Like our network investment team, our operating cost assessment team contains a number of individuals who have, through the RRP process, built up a good appreciation of each business and its cost structure. We have benefitted also from the support of an academic advisor, Melvyn Weeks, who specialises in benchmarking techniques. His report on our work is published as an appendix to the Cost Assessment document.

1.31. Comparative benchmarking analysis is not appropriate for all categories of costs (e.g. lumpy costs where it is difficult to conduct robust comparisons across the DNOs, or costs that are specific to particular DNOs). For example, rather than just benchmarking for wayleave costs and the costs of substation electricity, we have looked at historical levels of costs, industry trends and DNO forecasts. There are also areas where we need specialist support in carrying out the analysis. For this reason we appointed non-operational IT and property specialists to carry out a detailed review as well as including these costs in the benchmarking process.

Benchmarking analysis - key decisions

1.32. Benchmarking is a highly technical area, and we explain in full the methodology we have used in the Operational Cost Chapter. Below we set out the key decisions we have made in our analysis. In arriving at these we have sought to place appropriate weight on the results of different benchmarking techniques, while doing all we can to make sure that inefficiencies are not built into the DPCR5 allowances.

1.33. We have carried out benchmarking at different levels of disaggregation, broken down costs into a number of categories with their own cost driver, and also conducted top down regressions of overall costs. For each cost category we have had to decide whether we set the benchmark level at the frontier (i.e. the level of the most efficient company), the upper quartile (the top 25 per cent companies) or at the average level. In general our approach is to use the upper quartile, which means that all but the top 25 per cent will have to be more efficient than in DPCR4 if they are to live within the operating cost allowance we have set. We do not consider that our benchmarking results or the quality of the underlying data justify setting allowances according to the frontier, and to do so would discredit our work. However, to balance this we do not propose to allow the less efficient companies any time to reach the benchmark levels and they will apply from day one of DPCR5.

1.34. In the case of network operating costs (i.e. inspections and maintenance) the benchmarking results are weaker than elsewhere, perhaps because there is still not enough consistency in the reporting applied by DNOs to this cost category. In this case we propose to use a hybrid approach which brings DNOs with costs higher than the average down to the average level of efficiency and benchmarks those DNOs in the top 25 per cent at the upper quartile level of efficiency. Those companies between the upper quartile and average are given their own level of costs. For companies less efficient than the upper quartile we have capped our baseline at the companies' forecast. We consider that this addresses the uncertainty for these activities. We recognise that there may be some trade off between network operating costs and network investment. We have taken a holistic approach to make sure that we do not unfairly penalise companies by setting a low operating cost benchmark without recognising the impact on the level of network investment.

1.35. We have had to consider whether, in advance of our benchmarking, we should adjust historical costs for specific factors that might mean the efficient level of costs is higher in some regions than in others. This has been a controversial area and we have decided to apply adjustments for both regional labour and contractor costs, as well as a number of specific additional costs associated with particular networks. We have recognised in our benchmarking that it is more costly to work on both sparsely populated networks such as the Highlands and Islands, and on densely populated networks in London. We have also recognised that there are extra costs associated with running the interconnected network in SP Manweb's area.

2. DNOs' forecast business plans

Chapter Summary

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

DPCR5 forecasts - change from February submission

2.1. The DNOs have now submitted their June FBPQ forecasts. In the May Paper we made it clear that the DNOs would have to provide a detailed explanation and audit trail of areas where their June cost forecasts differed from those presented to us in February.

2.2. In the June FBPQs we changed some of the categorisation of costs in line with our policy development in the area of customer charges for demand connections.[1] Comparing the June FBPQ costs with the February FBPQ costs treated in the same way, the June FBPQs show approximately a 2 per cent reduction in network investment.[2] Similarly, the June FBPQs show approximately a 2 per cent reduction in network operating costs, indirect costs and non-operational capex from February.

2.3. All figures presented in this document are in 2007-08 prices.

DPCR5 forecasts - analysis against DPCR4 actual expenditure

Network investment

2.4. For presentation of the DNOs' June FBPQ forecasts we have categorised network investment as follows:

- asset replacement expenditure,
- general reinforcement expenditure and customer specific demand expenditure (associated with connections),
- other core expenditure including:
    - diversions,
    - legal and safety (but excluding critical national infrastructure (CNI) and rising mains and laterals (RML)), and

[1] In the June FBPQs customer contributions towards direct and indirect costs are separately identified and netted off the appropriate costs.
[2] Includes core and non-core network investment costs but excludes costs for the connection of distributed generation.

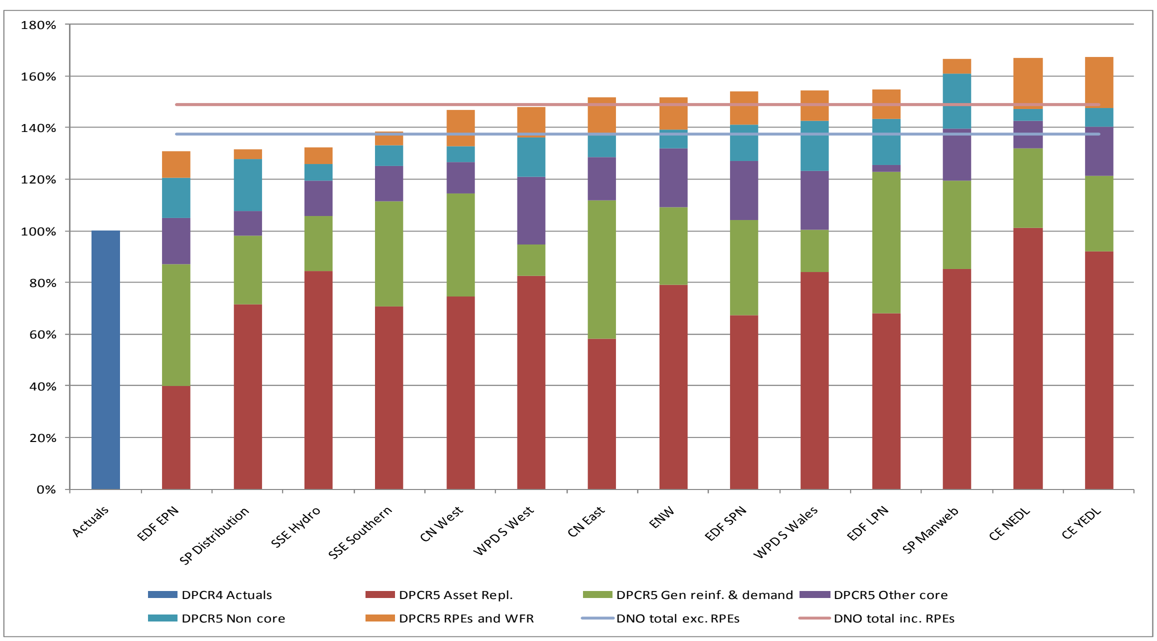
- operational IT and telecoms (but excluding expenditure relating to BT 21st century networks (BT21CN)).

- Non-core costs including:
    - high impact low probability events (HILP),
    - flooding,
    - BT21CN,
    - environmental costs (excluding investment for undergrounding in areas of outstanding natural beauty (AONB)),
    - QoS (excluding Worst Served Customers (WSC)),
    - CNI,
    - RML, and
    - Real price effects (RPEs) and workforce renewal (WFR).

2.5. Using this categorisation of costs, we have calculated the DNOs' network investment forecasts as a percentage of their expected actual levels of expenditure in DPCR4, as shown in Figure 2.1. Network investment to accommodate distributed generation (DG), for worst served customers and for undergrounding in AONB is not included in the chart as these areas are subject to standalone funding mechanisms.

2.6. Discretionary expenditure has also been excluded from the DNOs' forecasts as it is being separately addressed. Further details on discretionary expenditure are provided in Appendix 6.

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



2.7. In Figure 2.1, excluding RPEs and WFR, core expenditure makes up 91 per cent of DPCR5 network investment expenditure.

2.8. The forecast levels of network investment expenditure by DNO are detailed in Table 2.1. Figures presented are higher than those in the May Document because of a change in the treatment of customer contributions towards indirect costs,[3] re-forecasting by the DNOs, and because fluid filled cable (FFC) replacements are now included within asset replacement (rather than the environment building block).

Table 2.1 - Forecast network investment for DPCR5 against DPCR4 outturn

£m	DPCR4	DPCR5						Change DPCR4 to DPCR5
DNO	**Total**	**Asset Repl.**	**Gen reinf. & demand**	**Other core**	**Non core**	**RPEs and WFR**	**Total**	**%**
CN West	504	377	200	61	31	71	741	47%
CN East	490	285	263	82	42	72	744	52%
ENW	443	350	133	101	32	57	672	52%
CE NEDL	276	279	85	29	12	54	460	67%
CE YEDL	359	330	105	68	26	71	601	67%
WPD S Wales	159	134	26	37	31	19	246	55%
WPD S West	256	212	31	67	39	30	379	48%
EDF LPN	405	275	222	11	73	47	627	55%
EDF SPN	426	287	158	96	61	55	657	54%
EDF EPN	644	257	304	116	100	67	844	31%
SP Distribution	357	255	95	34	73	13	470	32%
SP Manweb	391	333	135	79	84	22	652	67%
SSE Hydro	179	151	38	25	11	12	237	32%
SSE Southern	522	369	213	71	42	28	724	39%
Total	**5412**	**3894**	**2009**	**877**	**656**	**618**	**8054**	**49%**

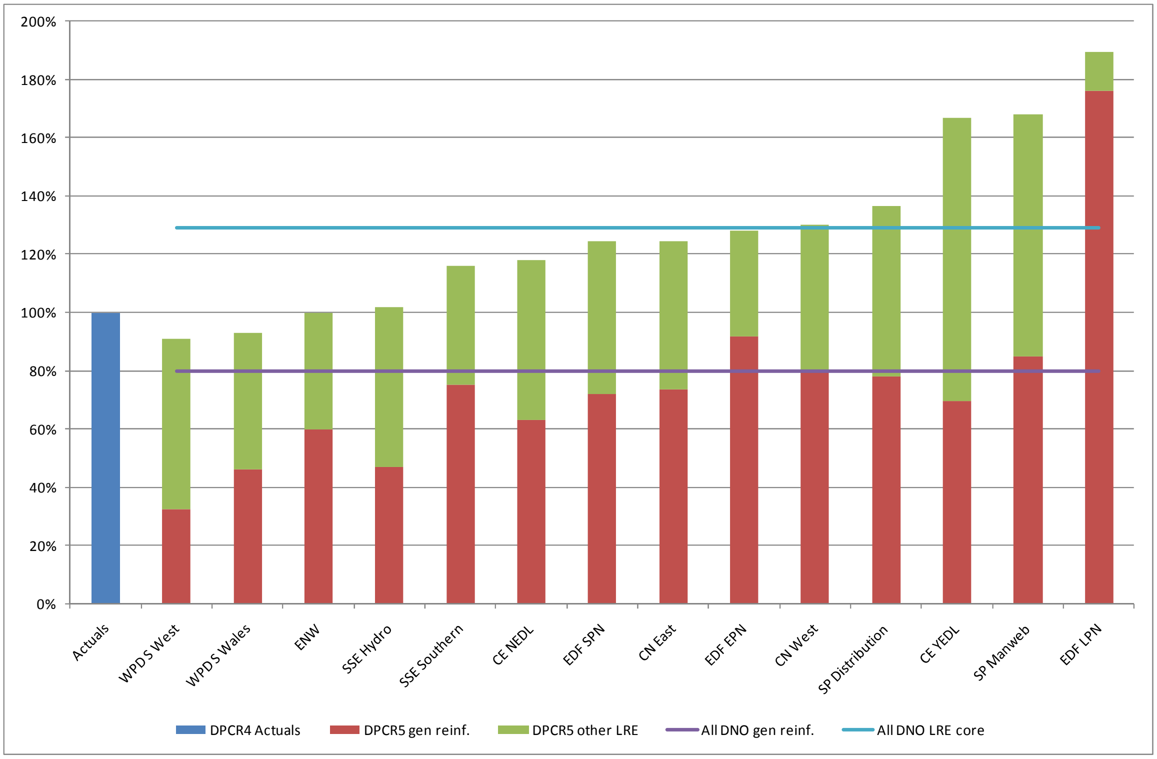
2.9. The DPCR4 costs include four years of actual expenditure and one year of forecast expenditure. Across the industry DNOs are forecasting a 49 per cent increase in network investment over DPCR4 levels. Core network investment is forecast to increase by 36 per cent across all DNOs, varying from 19 per cent for SP Distribution to 56 per cent for CE NEDL. Roughly £0.7 billion (or 24 per cent) of the additional expenditure in DPCR5 is forecast to come from non-core activities. Below we set out the changes in each of the categories in the table above.

Core net load related expenditure

2.10. Core net load related expenditure consists of general reinforcement expenditure, customer specific demand expenditure (less direct customer contributions), diversions and fault level expenditure. Figure 2.2 shows forecast core net load related expenditure, with general reinforcement separately identified.

[3] Policy has been changed for DPCR5 such that customer contributions towards connection costs are split between direct and indirect contributions and netted off the appropriate DNO costs. At DPCR4 all customer contributions were netted off DNO direct costs.

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



2.11. Taking the industry as a whole, DNOs are forecasting a 29 per cent increase in core load related expenditure over DPCR4. This varies from a reduction of 9 per cent for WPD S West to an increase of 90 per cent for EDFE LPN. Forecast levels of core net load related expenditure are shown in Table 2.2. In a number of areas the forecasts for general reinforcement are below DPCR4 levels showing the impact of a reduction of demand in recent years.

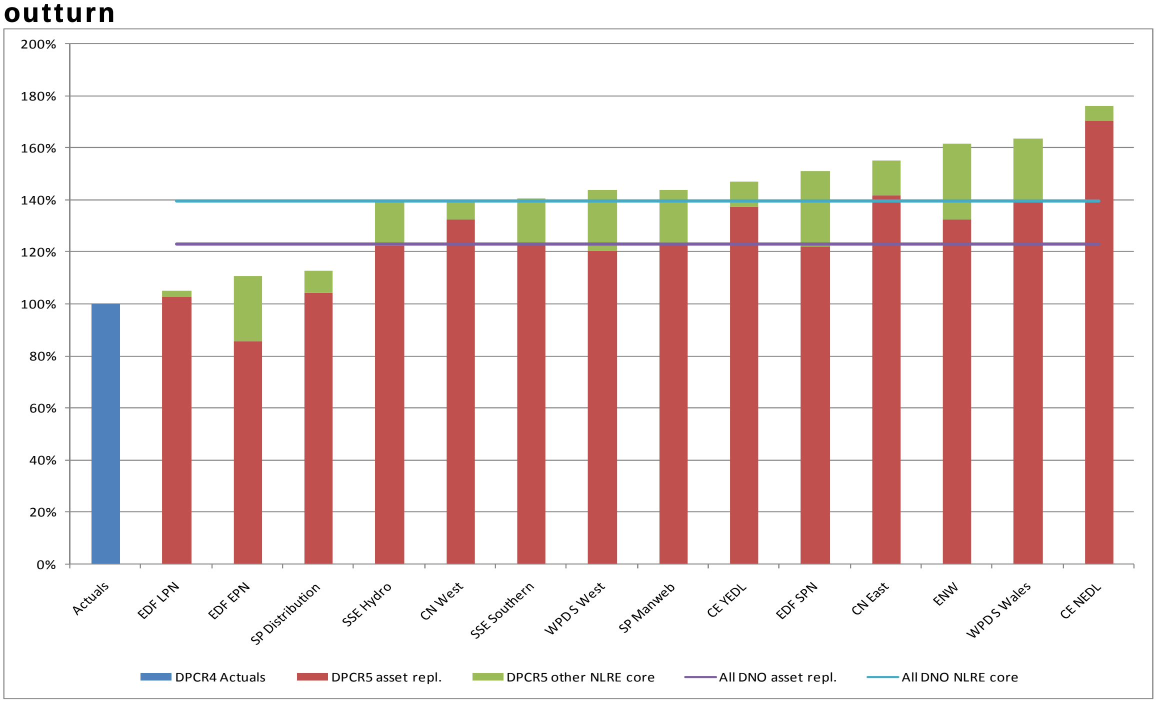
Table 2.2 - Core net load related expenditure for DPCR5 against DPCR4 outturn

£m	DPCR4			DPCR5			Change DPCR4 to DPCR5
DNO	Gen reinf	Other LRE	Total	Gen reinf	Other LRE	Total	%
CN West	103	83	186	149	93	242	30%
CN East	112	144	255	187	130	318	24%
ENW	68	89	157	94	63	156	0%
CE NEDL	61	28	89	56	49	105	18%
CE YEDL	49	41	90	63	87	150	67%
WPD S Wales	23	20	43	20	20	40	-7%
WPD S West	34	29	63	20	37	57	-9%
EDF LPN	104	15	119	210	16	226	90%
EDF SPN	70	80	149	107	79	186	24%
EDF EPN	198	71	269	247	98	344	28%
SP Distribution	44	35	79	62	46	108	37%
SP Manweb	38	57	94	80	79	159	68%
SSE Hydro	23	19	42	20	23	42	2%
SSE Southern	169	31	200	150	82	232	16%
Total	**1095**	**740**	**1835**	**1464**	**901**	**2365**	**29%**

Core non-load related expenditure

2.12. Core non load related expenditure consists of expenditure on asset replacement, legal and safety works (excluding expenditure on CNI and RML) and operational IT and Telecoms (excluding BT 21st Century expenditure). Core non load related expenditure is shown in Figure 2.3 with asset replacement expenditure separately identified.

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



2.13. All DNOs are forecasting an increase in core non-load related expenditure over DPCR4, with an increase across the industry forecast at 39 per cent. The forecast increases range from 5 per cent for EDFE LPN to 76 per cent for CE NEDL. Expenditure on asset replacement is forecast to increase in all but one DNO. EDFE EPN is forecasting a reduction in asset replacement expenditure of 4 per cent. Forecast levels of core non-load related expenditure are detailed in Table .

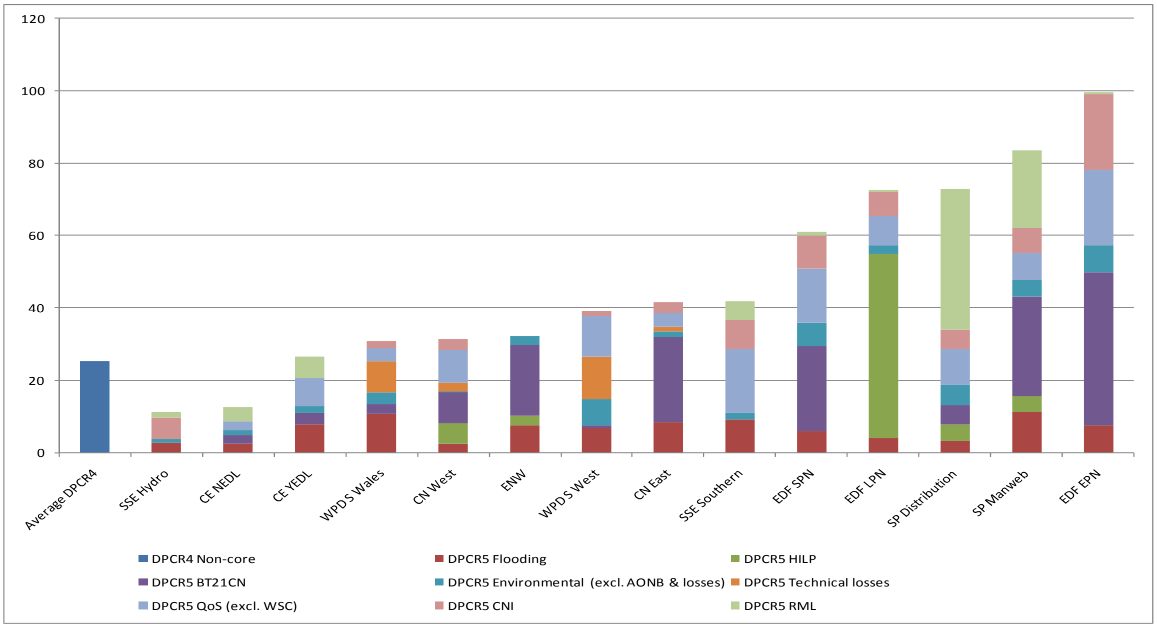
Table 2.3 – Core non-load related expenditure for DPCR5 against DPCR4 outturn

£m	DPCR4			DPCR5			Change DPCR4 to DPCR5
DNO	**Asset repl.**	**Other NLRE**	**Total**	**Asset repl.**	**Other NLRE**	**Total**	**%**
CN West	270	14	284	377	20	396	40%
CN East	191	10	201	285	28	313	55%
ENW	236	29	264	350	78	428	62%
CE NEDL	155	9	164	279	9	288	76%
CE YEDL	217	23	240	330	23	354	47%
WPD S Wales	85	11	96	134	23	156	64%
WPD S West	158	18	176	212	41	253	44%
EDF LPN	255	14	268	275	7	282	5%
EDF SPN	214	22	235	287	69	355	51%
EDF EPN	268	32	300	257	76	333	11%
SP Distribution	223	22	245	255	21	275	13%
SP Manweb	234	36	269	333	55	388	44%
SSE Hydro	118	5	124	151	21	172	39%
SSE Southern	293	6	300	369	52	421	41%
Total	**2916**	**250**	**3166**	**3894**	**521**	**4415**	**39%**

Non-core expenditure

2.14. Non-core expenditure includes expenditure on major system risks (flooding and HILP), environmental works (excluding undergrounding in AONB), QoS (excluding worst-served customers (WSC), Critical National Infrastructure (CNI), Rising Mains and Laterals (RML) and BT 21st Century). These are largely new areas of expenditure for DPCR5, in many cases driven by external stakeholders. Most DNOs consulted on these areas of expenditure to some extent in their stakeholder engagement. As discussed in Chapter 2, discretionary expenditure has been excluded, and further details on discretionary expenditure are provided in Appendix 6. Non-core expenditure is shown in Figure 2.4.

Figure 2.4 - Non-core network investment forecasts



2.15. Much of the non-core expenditure addresses new areas of investment (for example expenditure on mitigating the risks of flooding). The "Environmental" costs within non-core include expenditure on technical losses, noise pollution, SF6 leakage and mitigation of the risk of oil pollution. All but two DNOs are forecasting an increase in non-core expenditure over DPCR4. There is a very large range in forecasts from £11 million for SSE Hydro to £100 million for EDFE EPN.

2.16. EDFE LPN is forecasting £51 million for HILP investment. SP Distribution and SP Manweb are forecasting £39 million and £21 million RML works respectively. ENW, CN East, EDFE SPN and SP Manweb are forecasting between £20 million and £28 million for BT21CN and EDFE EPN are forecasting £42 million. Full details of the forecast non-core network investment expenditure are given in Table .

Table 2.4 - Non-core network investment forecasts (£m)

£m	DPCR4	DPCR5									Change DPCR4 to DPCR5
DNO	Non-core	Flooding	HILP	BT21CN	Environmental (excl. AONB & losses)	Technical losses	QoS (excl. WSC)	CNI	RML	Total	%
CN West	28	2	6	9	0	2	9	3	0	31	13%
CN East	27	8	0	23	2	1	4	3	0	42	54%
ENW	19	7	3	20	2	0	0	0	0	32	71%
CE NEDL	18	3	0	2	1	0	2	0	4	12	-31%
CE YEDL	22	8	0	3	2	0	8	0	6	26	20%
WPD S Wales	18	11	0	3	3	9	4	2	0	31	70%
WPD S West	14	7	0	1	7	12	11	1	0	39	181%
EDF LPN	13	4	51	0	3	0	8	7	1	73	453%
EDF SPN	37	6	0	24	7	0	15	9	1	61	64%
EDF EPN	68	8	0	42	8	0	21	21	1	100	47%
SP Distribution	31	3	5	6	6	0	10	6	39	73	136%
SP Manweb	25	11	4	28	5	0	8	7	21	84	230%
SSE Hydro	12	3	0	0	1	0	0	6	2	11	-9%
SSE Southern	19	9	0	0	2	0	18	8	5	42	121%
Total	**351**	**90**	**68**	**160**	**47**	**24**	**117**	**72**	**78**	**656**	**87%**

Operational costs

2.17. These costs have been categorised initially into four cost categories:

- network operating costs (NOCs)
- indirect costs
- non-operational capex, and
- real price effects (RPEs).

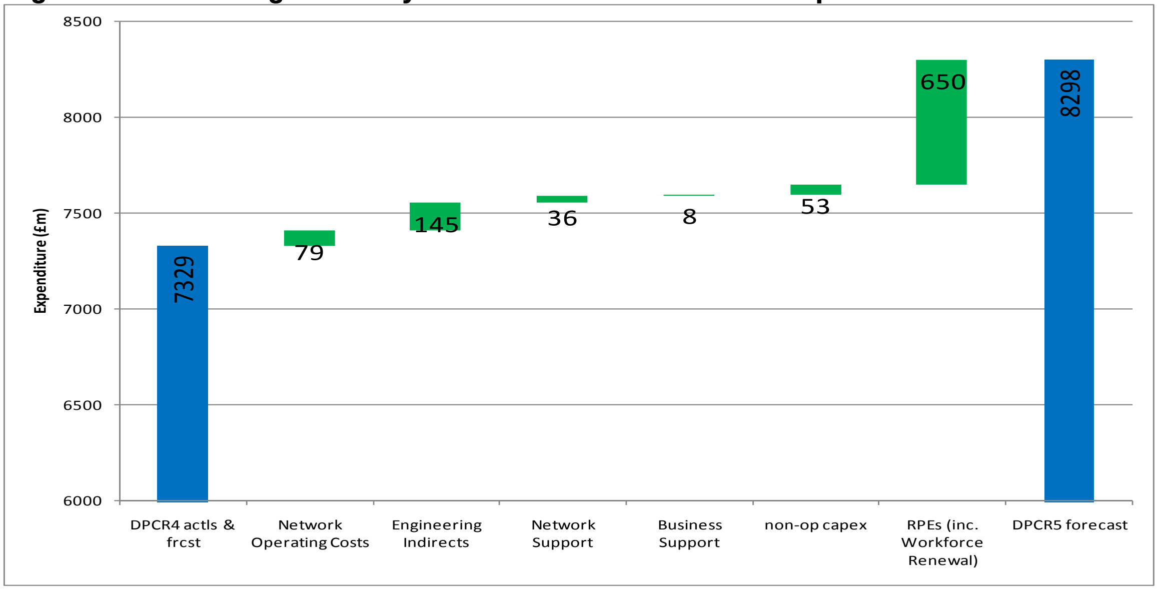
2.18. NOCs include the activities of faults, inspections and maintenance, tree cutting and 'other' activities consisting of Traffic Management costs, unmetered electricity and dismantlement.

2.19. Indirect costs includes those activities which are more closely aligned to network investment and operation (network design, project management, call centre, system mapping, etc) and those which provide a more general level of business support (IT, finance and regulation, HR, etc). Although costs for each subgroup are reported in the FBPQ submissions as Engineering Indirects, Network Investment Support and Business Support, the data presented in Table 5 as "indirects" is the combination of all three.

2.20. Non-operational capex includes the purchase of new or replacement items not recognised as part of the system assets (vehicles, tools, machinery, office equipment, non-operational IT, etc).

2.21. Figure 2.5 shows the total outturn costs expected for DPCR4 together with the increases in costs in the DPCR5 period, split between the cost categories noted above. The total cost forecast by the DNOs for DPCR5 compared to DPCR4 is £8.3bn.

Figure 2.5 – Changes in key cost areas for DPCR5 compared to DPCR4



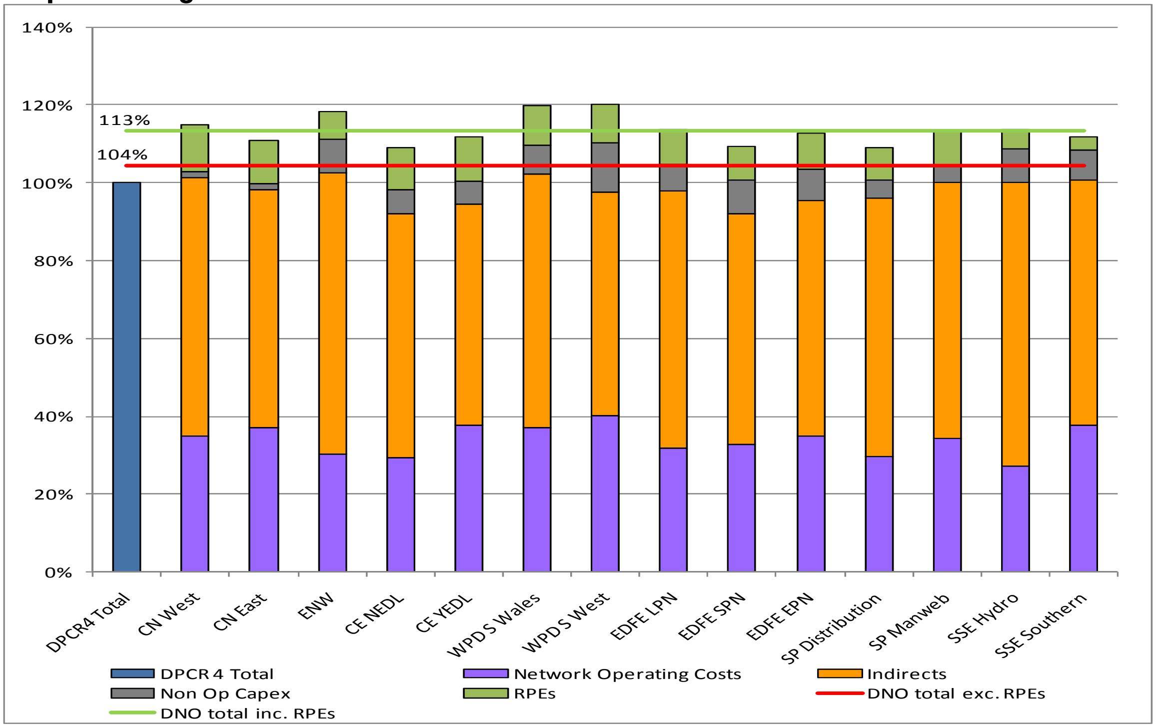
2.22. The largest increase in forecast cost arises from increases in RPEs (including workforce renewal) of £650m, accounting for 67 per cent of the increase over DPCR4. This is a reduction in the figure submitted by the DNOs in their February FBPQ submissions where the RPE component was £702m . The next largest increase in forecast costs is due to Engineering Indirects of £145m (15 per cent). The increase in Network Operating Costs of £79m over the five year period represents just 8 per cent of the total increase compared to DPCR4, although we note that this activity has been revised upward from £70m since the February submission.

2.23. The following sections present the forecasts on a per DNO basis compared to DPCR4. Firstly we present results for total operational activities, followed by the three subgroups identified above – network operating costs, indirects and non-operational capex.

Overall Operational activities

2.24. Figure 2.6 illustrates the changes in costs on a per DNO basis split between the high level cost categories. Overall the DNOs are forecasting a 13 per cent increase in costs compared to DPCR4; excluding Real Price Effects (RPEs) this figure is just 4 per cent.

Figure 2.6 - Network Operating Costs, Indirects and Non-Operational capex as percentage of DPCR4 totals



2.25. Indirect costs represent 56 per cent of the total forecast Operational Activities for the DNOs in DPCR5, with Network Operating Costs the next highest at 30 per cent. There are significant ranges across the DNOs, e.g. indirect costs represent only 48 per cent of DPCR5 forecast expenditure for WPD S West but 64 per cent for SSE Hydro.

2.26. When RPEs are excluded there are three DNOs (CN East, CE NEDL and CE YEDL) that forecast costs for DPCR5 at or below their DPCR4 levels.

Table 2.5 – DPCR5 forecast expenditure for Operational Activities compared to DPCR4 outturn.

DNO	DPCR 4 Total	DPCR 5					DR4 to DR5
		Network Operating Costs	Indirects	Non Op Capex	RPEs	Total	
CN West	586	205	388	9	70	672	15%
CN East	582	217	355	10	64	645	11%
ENW	597	181	431	53	42	706	18%
CE NEDL	389	115	243	23	43	424	9%
CE YEDL	487	183	278	28	55	545	12%
WPD S Wales	306	113	199	23	31	367	20%
WPD S West	429	173	247	55	42	516	20%
EDFE LPN	550	175	364	37	49	625	14%
EDFE SPN	552	181	327	47	48	603	9%
EDFE EPN	899	315	543	73	82	1013	13%
SP Distribution	489	145	325	22	41	532	9%
SP Manweb	489	168	321	22	44	554	13%
SSE Hydro	331	90	241	29	16	376	14%
SSE Southern	642	243	404	50	23	719	12%
Total	**7329**	**2503**	**4667**	**479**	**650**	**8298**	**13%**

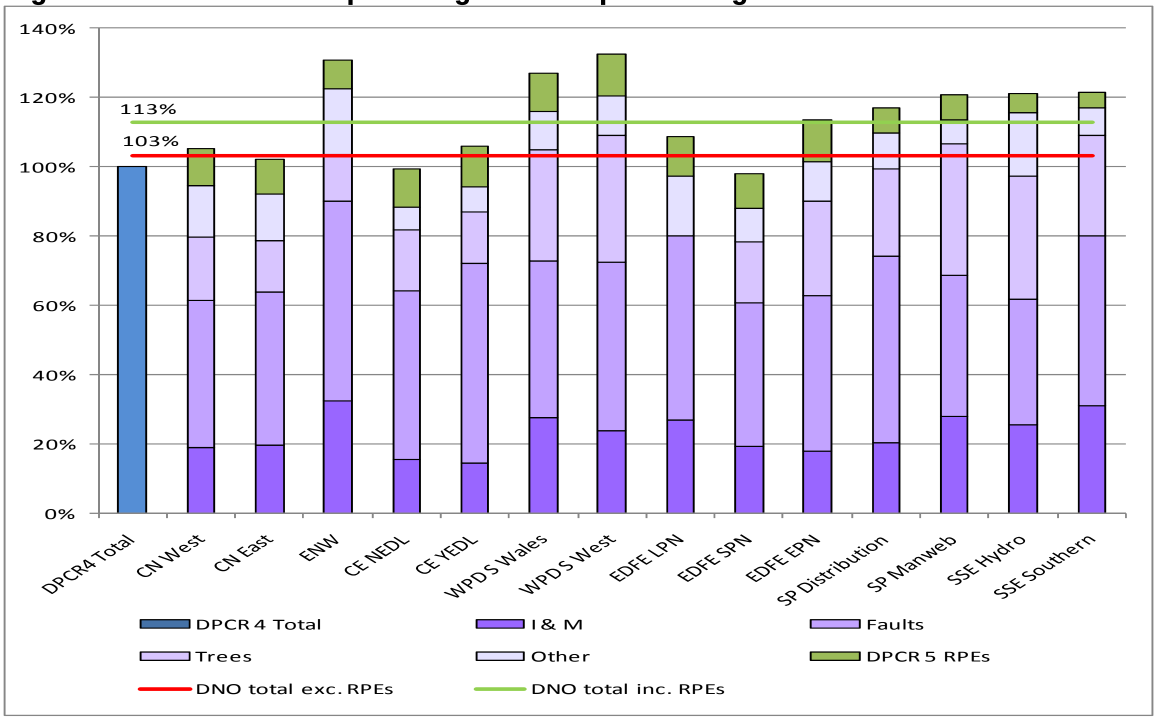
2.27. Including RPEs, three DNOs (CE NEDL, EDFE SPN and SP Distribution) indicate a 9 per cent increase, while the WPD DNOs forecast the largest increase of 20 per cent increase in costs compared to DPCR4.

Network Operating Costs

2.28. Network Operating Costs cover the activities of inspections and maintenance, faults, tree cutting and other. The industry forecasts are also 13 per cent above the DPCR4 figures, mirroring the change in the overall operational costs. However, there is a much wider range across the DNOs. WPD and ENW are forecasting increases over 30 per cent, while CE NEDL and EDFE SPN indicate slight reductions.

2.29. Excluding RPEs the DNOs are forecasting increases of 3 per cent above DPCR4 levels overall.

Figure 2.7 - Network Operating Cost as percentage of DPCR4 totals



2.30. The largest forecast increases in costs are for NOCs relating to Tree Cutting, where the DNOs have forecast a 31 per cent increase on average. An increase in costs was expected as the DNOs implement the new requirements for the Electricity Safety, Quality and Continuity Regulations 2002 (ESQCR), as amended in 2006.

2.31. ENW have the largest forecast increase in NOCs at 23 per cent, the majority of which relates to Other NOCs, specifically TMA costs. EDFE SPN forecast a decrease of 11 per cent mostly relating to faults.

2.32. Excluding RPEs, CN, CE, EDFE LPN and EDFE EPN have forecast a drop in NOCs compared to DPCR4.

Table 2.6 – DPCR5 forecast expenditure for Network Operating Costs compared to DPCR4 outturn

DNO	DPCR 4 Total	DPCR 5 I & M	Faults	Trees	Other	RPEs	Total NOC	DR4 to DR5
CN West	217	41	92	40	32	24	229	5%
CN East	235	46	103	35	32	23	240	2%
ENW	148	48	85	20	28	12	193	31%
CE NEDL	130	20	63	23	9	14	129	-1%
CE YEDL	195	28	113	28	14	23	206	6%
WPD S Wales	98	27	44	32	11	11	124	27%
WPD S West	143	34	70	53	17	17	190	33%
EDFE LPN	179	49	95	0	31	20	195	9%
EDFE SPN	205	40	85	36	20	20	201	-2%
EDFE EPN	310	56	138	84	36	37	351	14%
SP Distribution	132	27	71	33	14	9	154	17%
SP Manweb	148	41	60	57	10	11	179	21%
SSE Hydro	78	20	28	28	14	4	94	21%
SSE Southern	207	64	102	60	17	9	252	22%
Total	**2424**	**542**	**1149**	**528**	**283**	**236**	**2738**	**13%**

2.33. There are wide variations in the change in costs forecast for DPCR5 compared to DPCR4 for each of the activities included within NOCs:

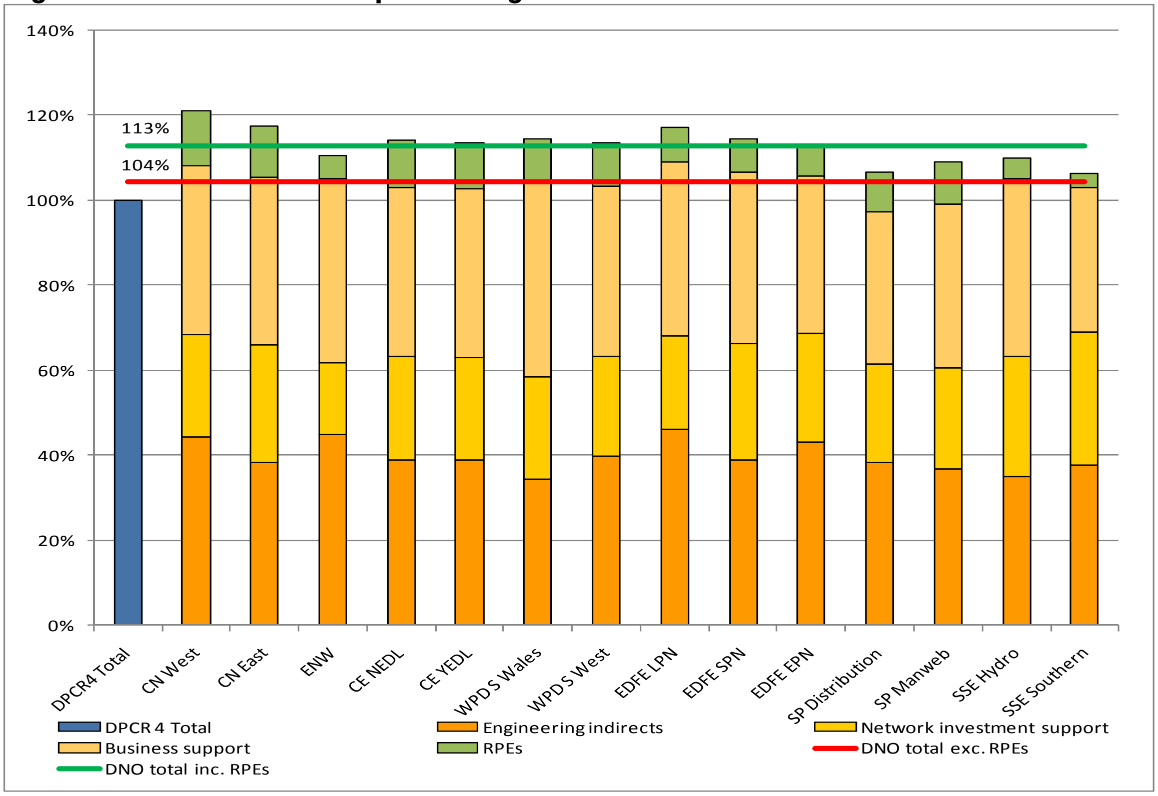
- For Inspections and Maintenance ENW forecast an increase of 29 per cent while CN East forecast a decrease from DPCR4 totals of 12 per cent.
- For Faults, SSE Hydro forecast an increase of 3 per cent while EDFE SPN forecast a decrease of 28 per cent.
- For Tree Cutting WPD S West forecast an increase of 79 per cent while CE YEDL report a decrease of 15 per cent.
- The forecast for Other NOCs shows an even higher variation in the forecasts with SP Manweb forecasting an increase above 300 per cent while SSE Hydro only forecasts an increase of 1 per cent.

Indirect costs

2.34. Indirects costs cover the three categories referred to in the FBPQ as Engineering Indirects, Network Investment Support and Business Support. These groupings of activities 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, and
- Business Support: IT & Telecoms, Property Management, HR & Non-Operational Training, Finance & Regulation and CEO etc.

Figure 2.8 - Indirects as percentage of DPCR4 totals



2.35. The DNOs' forecasts excluding RPEs for total indirects fall within a relatively narrow range compared to the other operational costs. Only one DNO (SP) indicates DPCR5 costs excluding RPEs falling below DPCR4 levels. The biggest increases (excluding RPEs) are recorded for EDFE LPN and CN West at 9 per cent and 8 per cent respectively.

2.36. Most of the 4 per cent increase in forecast indirect costs relative to DPCR4 relates to engineering indirects. Across the DNOs this activity is forecast at 10 per cent above DPCR4 levels, contrasting with a modest increase of 1 per cent for business support activities.

Table 2.7 – DPCR5 forecast expenditure for Indirect Costs compared to DPCR4 outturn

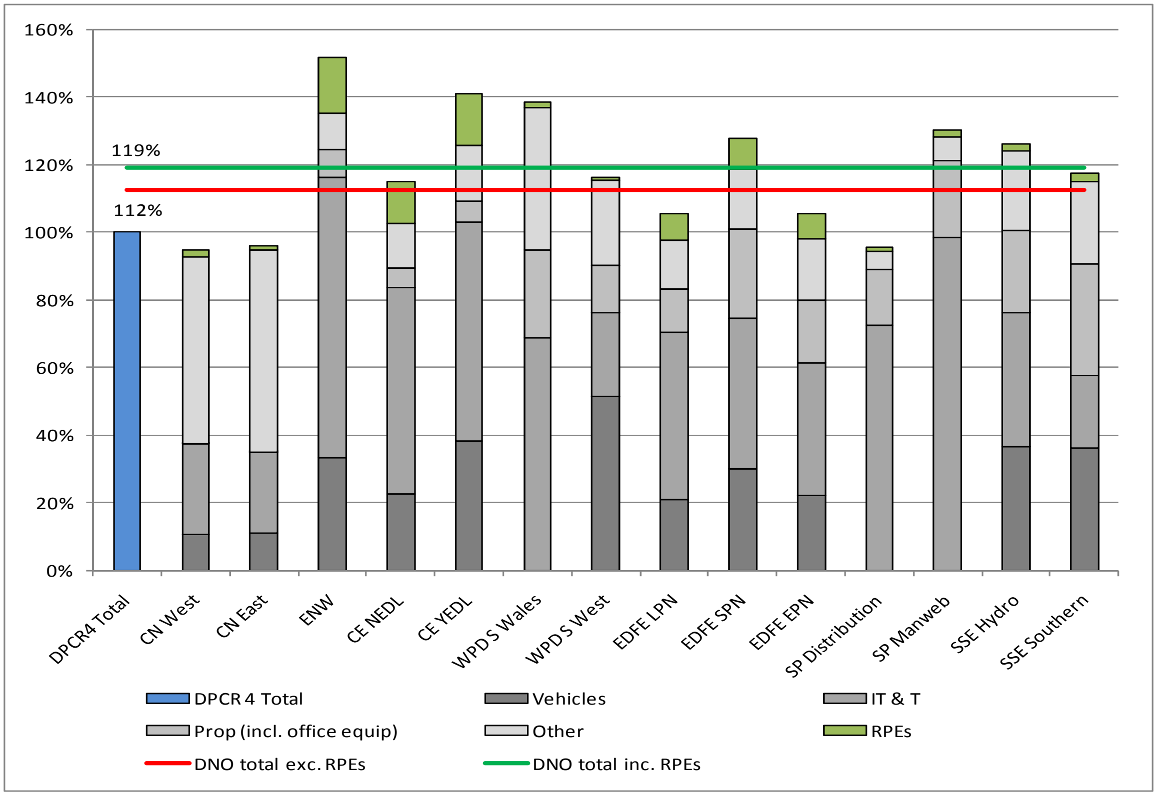
DNO	DPCR 4 Total	DPCR 5					DR4 to DR5
		Engineering indirects	Network investment support	Business support	RPEs	Total Indirects	
CN West	359	159	86	143	46	434	21%
CN East	337	129	93	132	41	395	17%
ENW	410	184	70	177	23	454	11%
CE NEDL	236	92	58	94	26	269	14%
CE YEDL	270	105	65	108	29	307	14%
WPD S Wales	191	66	46	88	19	219	14%
WPD S West	239	95	56	96	25	272	14%
EDFE LPN	333	154	74	136	26	390	17%
EDFE SPN	307	120	84	124	24	351	14%
EDFE EPN	515	222	131	190	40	583	13%
SP Distribution	334	128	76	120	31	356	7%
SP Manweb	324	119	77	125	32	353	9%
SSE Hydro	230	80	65	95	11	252	10%
SSE Southern	392	148	123	133	13	417	6%
Total	**4479**	**1801**	**1103**	**1762**	**386**	**5053**	**13%**

2.37. All DNOs are forecasting rises in engineering indirects, with the biggest increase reported from EDFE SPN at 21 per cent above DPCR4 (before RPEs). CN East is reporting a 3 per cent increase. For network/investment support the values range from a decrease of 6 per cent for SP Distribution to an increase of 14 per cent for CN West. There is a wide divergence of forecasts for the business support category. The biggest increases are reported by CN at 7 per cent with SP Distribution forecasting a decrease of 7 per cent against DPCR4.

Non-operational capex

2.38. This represents the expenditure DNOs make on purchases of new or replacement items not recognised as part of the system assets (vehicles, tools, machinery, office equipment, non-op IT, and non-operational property). The expenditure profile for this activity is typically "lumpy" and the largest spend is usually in the non-op IT category. The increase overall between DPCR4 and DPCR5 is 19 per cent, with ENW forecasting a 52 per cent increase. Most DNOs are showing increases above DPCR4 except CN and SP Distribution.

Figure 2.9 – Non-Operational capex as percentage of DPCR4 totals



2.39. The DPCR5 total spend on non-operational capex is forecast to be £480m before RPEs, up 13 per cent on DPCR4 levels. The forecasts reveal an uplift in non-operational IT expenditure. Total spend on non-operational IT is forecast to rise 29 per cent to a little over £200m across the DNOs. The forecast expenditure in the next biggest category, vehicles, is 4 per cent below DPCR4. Expenditure on non-operational property is forecast to be 14 per cent up on DPCR4.

Table 2.8 – DPCR5 forecast expenditure for Non-Operational capex compared to DPCR4 outturn

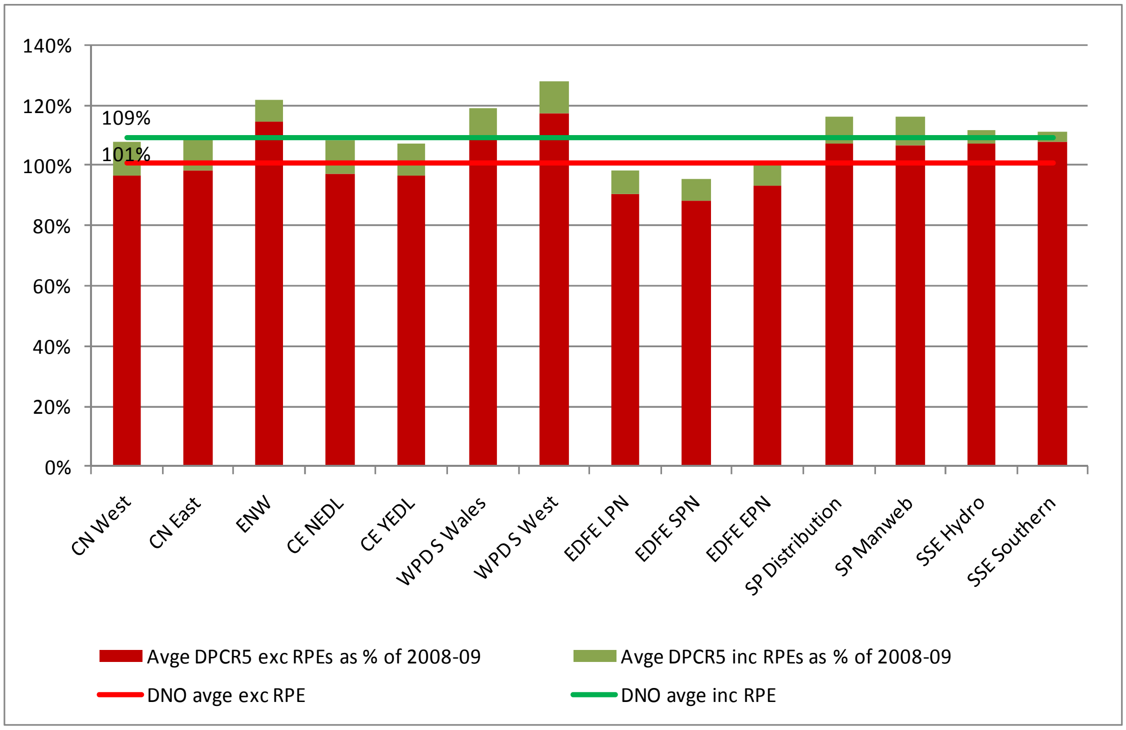
DNO	DPCR 4 Total	Vehicles	IT & T	Prop (incl. office equip)	Other	RPEs	Total Non-op Capex	DR4 to DR5
CN West	10	1	3	0	6	0	10	-5%
CN East	10	1	2	0	6	0	10	-4%
ENW	39	13	32	3	4	7	59	52%
CE NEDL	23	5	14	1	3	3	26	15%
CE YEDL	22	9	14	1	4	3	31	41%
WPD S Wales	17	0	12	4	7	0	24	39%
WPD S West	47	24	12	7	12	0	55	16%
EDFE LPN	37	8	19	5	6	3	39	5%
EDFE SPN	40	12	18	11	7	4	51	28%
EDFE EPN	75	17	29	14	14	6	79	5%
SP Distribution	23	0	17	4	1	0	22	-4%
SP Manweb	17	0	17	4	1	0	22	30%
SSE Hydro	23	9	9	6	6	0	29	26%
SSE Southern	43	16	9	14	11	1	50	17%
Total	**426**	**113**	**206**	**74**	**86**	**28**	**507**	**19%**

DPCR5 average forecast compared to 2008-09.

2.40. The comparisons to date have considered DPCR5 costs compared to DPCR4. However, DPCR4 has been a period of increasing capex and DNOs have ramped up at different rates. Figure 2.10 compares the average DPCR5 forecasts against the actual costs in 2008-09. It shows markedly different results across the DNOs. RPEs lift the industry average to 9 per cent above the 2008-09 level, although ENW, WPD and SP report DPCR5 averages significantly higher than this.

2.41. Only EDFE is reporting forecast average DPCR5 costs (including RPEs) below or near their 2008-09 costs. However, excluding RPEs most of the DNOs are reporting DPCR5 average costs close to 2008-09 levels. The costs reported for the EDFE DNOs in 2008-09 are high compared to the other DPCR4 years, and therefore the comparison to DPCR5 average costs show the EDFE DNOs comparatively very low. Otherwise the comparisons show a similar picture to the total DPCR5 to DPCR4 comparison.

Figure 2.10 – Average DPCR5 opex as a percentage of 2008 – 09 opex



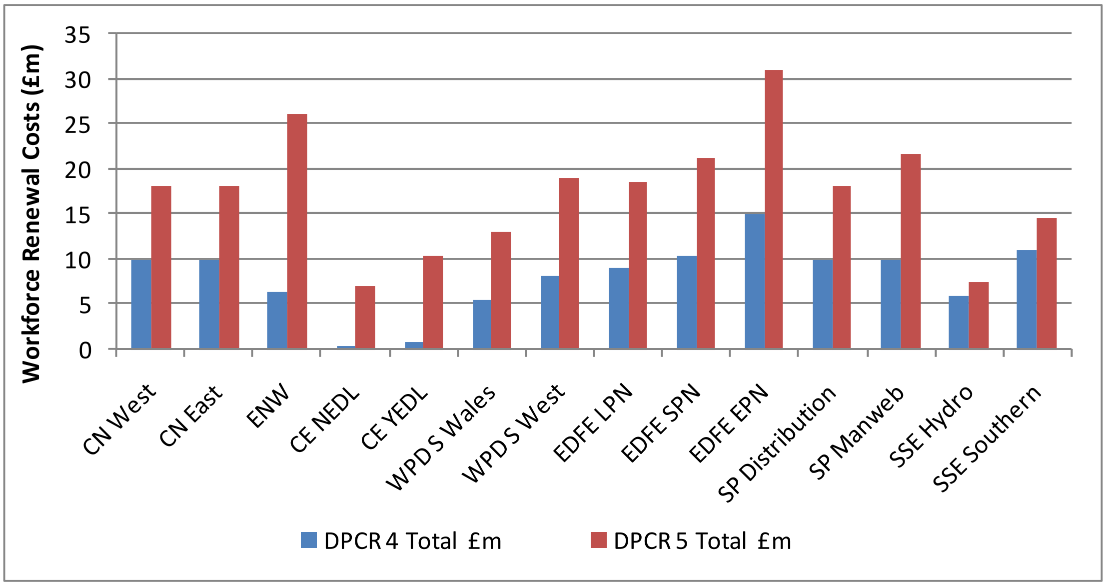
2.42. The comparison of average DPCR5 annual cost to 2008-09 actuals shows a notably reduced increase than for DPCR5 costs in total compared to DPCR4. This is explained because 2008-09, the last year for which we have actual costs for the DNOs is significantly higher than the average cost for the DPCR4 period, due to RPEs. The increase compared to 2008-09 actuals excluding RPEs is just 1 per cent.

Workforce Renewal

2.43. 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.

2.44. Workforce Renewal costs have been reported in the FBPQs for both Network Investment and Operational Activities. Figure 2.11 shows the reported costs for Workforce Renewal in total for DPCR4 and DPCR5.

Figure 2.11 - Workforce Renewal actual and forecast costs (£ million 2007-08 prices)



2.45. 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 2.9 below gives more detail of the costs the DNOs have reported and splits the costs between Network Investment and Operational Activities.

Table 2.9 - 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	5	5	**10**	10	8	**18**
CN East	5	5	**10**	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	**9**	2	16	**19**
EDFE SPN	1	10	**10**	3	19	**21**
EDFE EPN	1	14	**15**	4	27	**31**
SP Distribution	6	4	**10**	13	6	**18**
SP Manweb	6	4	**10**	15	7	**22**
SSE Hydro	5	2	**6**	5	2	**7**
SSE Southern	9	3	**11**	11	4	**15**
Totals	**47**	**66**	**113**	**105**	**140**	**245**

3. Network Investment

Chapter summary

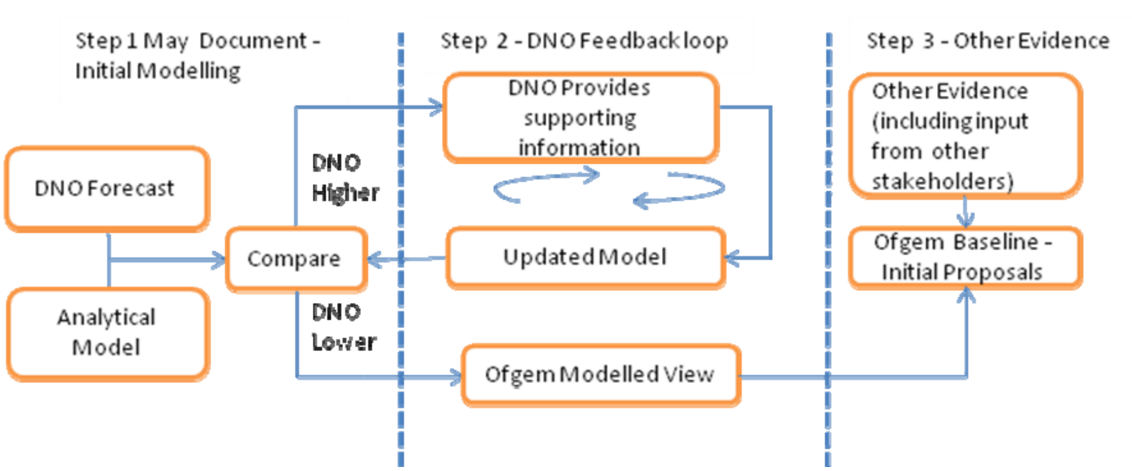
This chapter gives an overview of the methodologies used in the assessment of network investment costs, developments since the May document and our initial proposals for network investment allowances.

Methodology and update of results from May paper

3.1. In the May Methodology and Initial Results Paper we presented details of our methodology for assessing network investment requirements. An overview of this methodology is presented in Figure 1. We also presented the results of our initial modelling which formed step 1 of our approach. Since the publication of the Methodology and Initial Results Paper we have conducted bilateral meetings with each of the DNO groups to allow feedback on the initial results. Key issues raised at bilateral are discussed in more detail below. We have also received responses to supplementary questions, allowing the DNOs to make their case for specific areas of expenditure based on detailed bottom-up evidence.

3.2. This process has resulted in an updated Ofgem modelled view (step 2) which along with other evidence (step 3) has fed into our proposed baseline for network investment.

Figure 3.1 - Network investment methodology



Key issues raised at Bilateral meetings

3.3. After the publication of the May Methodology and Initial Results Paper Ofgem held a series of bilateral meetings with the DNOs. The purpose of these meetings was to:

- give the DNOs an opportunity to provide feedback on the methodology and initial results,

- allow Ofgem to provide an initial view of the baseline for initial proposals, highlighting areas where there was a proposed reduction to the DNOs forecast, and

- agree the additional information each DNO would need to provide to support their forecast expenditure and in order for us to move from our initial view.

3.4. In relation to the methodology and initial results the majority of issues raised by the DNOs related to the asset replacement modelling and the EHV and 132kV reinforcement modelling. Some of the key issues raised were:

- the quality and consistency of the input data,

- appropriateness of using historical volumes and inferred asset lives to determine future replacement requirements,

- impact of DNOs with unique practices distorting the calculated asset lives through low/high replacement volumes,

- large ranges in the cost of adding capacity between different reinforcement projects,

- ability to define added capacity for interconnected networks, and

- model treatment of substations that are currently fully utilised as result of historical load growth.

3.5. Where appropriate we have taken on board the DNOs' concerns and adjusted our approach accordingly. This is described in more detail in the following sections.

3.6. To formalise the process through which DNOs provided additional information in response to our views, we created a question and answer log. We have reviewed the DNOs' responses and taken them into account in developing our proposed baseline for network investment. This is set out in detail in the following sections.

Overview of core network investment initial proposals

3.7. As outlined in the May Methodology and Initial Results Paper we have divided network investment forecasts into "Core" and "Non-core" expenditure. The characteristics of core expenditure are that it is non-discretionary, has higher levels of certainty, and is not subject to a direct incentive mechanism other than the overall equalised cost incentive. We consider core expenditure to consist of:

- customer specific demand connections,
- general reinforcement expenditure,

- fault level expenditure,
- diversions expenditure,
- asset replacement expenditure,
- legal and safety expenditure, and
- operational IT and telecoms expenditure (excluding BT 21st century).

3.8. An overview of the DNO forecasts and our initial proposals for core network investment by DNO is presented in the two Tables below. Table 1 shows, for each DNO, Ofgem's proposed baselines alongside the DNO's actual expenditure in DPCR4 and their forecasts for DPCR5. It also shows the increase from DPCR4 actuals to Ofgem's proposed baseline (£m and percentage). Table 2 shows the overall position at an industry level for each of the core network investment building blocks. These tables exclude RPEs and workforce renewal and are prior to any pension adjustments. Workforce renewal is addressed as part of Chapter 4 on Operational activities.

Table 3.1 - Core Network Investment baseline initial proposals – By DNO

Core Network Investment								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	470.1	638.6	35.8%	554.1	84.5	13.2%	84.0	17.9%
CN_East	456.6	630.5	38.1%	542.5	88.0	14.0%	85.9	18.8%
ENW	421.1	583.9	38.7%	474.6	109.2	18.7%	53.6	12.7%
CE_NEDL	252.7	393.4	55.7%	345.5	47.8	12.2%	92.9	36.8%
CE_YEDL	330.5	503.7	52.4%	425.8	77.8	15.5%	95.4	28.9%
WPD_S_Wales	138.6	196.3	41.6%	182.6	13.7	7.0%	44.0	31.7%
WPD_S_West	238.3	309.5	29.9%	287.2	22.3	7.2%	48.9	20.5%
EDFE_LPN	387.5	508.1	31.1%	431.4	76.7	15.1%	43.9	11.3%
EDFE_SPN	384.4	541.2	40.8%	448.6	92.6	17.1%	64.2	16.7%
EDFE_EPN	569.1	676.7	18.9%	545.8	130.9	19.3%	-23.3	-4.1%
SP_Distribution	323.7	383.6	18.5%	343.0	40.5	10.6%	19.3	6.0%
SP_Manweb	363.8	546.7	50.3%	482.2	64.5	11.8%	118.5	32.6%
SSE_Hydro	165.0	214.2	29.8%	199.5	14.7	6.9%	34.5	20.9%
SSE_Southern	499.8	653.5	30.8%	567.8	85.7	13.1%	68.1	13.6%
Total	**5001.1**	**6779.8**	**35.6%**	**5830.8**	**948.9**	**14.0%**	**829.8**	**16.6%**

3.9. Ofgem's proposed level of network investment across the industry is a 16.6 per cent increase on current levels of investment. Overall, this represents a 14.0 per cent reduction to the DNOs forecast, ranging from a 7.0 per cent reduction for WPD South Wales to 19.3 per cent for EDFE EPN.

Table 3.2 - Network Investment baseline initial proposals – By Building Block

All DNO Total								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
Demand Connections	442.5	410.1	-7.3%	410.1	0.0	0.0%	-32.4	-7.3%
Diversions	259.1	355.7	37.3%	287.8	67.9	19.1%	28.7	11.1%
Reinforcement	1095.2	1464.2	33.7%	1312.8	151.4	10.3%	217.6	19.9%
Fault Levels	38.2	135.1	253.3%	125.8	9.3	6.9%	87.6	229.0%
Asset Replacement	2916.0	3893.9	33.5%	3332.8	561.0	14.4%	416.8	14.3%
Operational IT&T	82.4	106.2	28.8%	95.8	10.3	9.7%	13.4	16.3%
Legal and Safety	167.6	414.6	147.4%	265.6	149.0	35.9%	98.1	58.5%
Total	5001.1	6779.8	35.6%	5830.8	948.9	14.0%	829.8	16.6%

3.10. Overall we are looking to make the biggest cut in £m to asset replacement but this will still result in more than a 14.3 per cent increase in allowances from the DPCR4 expenditure levels. An overview of Ofgem's proposed reduction to the DNO's forecast split by areas of investment is shown in table 3.3 below.

Table 3.3 - Network Investment proposed reductions by building block – By DNO

DNO £m (07/08 prices)	Demand	Diversions	Reinforcement	Fault Levels	Asset Replacement	IT&T	Legal & Safety	Total
CN_West	0.0	5.5	21.0	6.1	49.0	0.0	2.9	84.5
CN_East	0.0	7.4	28.6	0.0	48.6	0.0	3.5	88.0
ENW	0.0	10.9	6.4	0.0	65.9	1.4	24.6	109.2
CE_NEDL	0.0	4.5	0.0	0.0	42.7	0.0	0.7	47.8
CE_YEDL	0.0	13.3	0.0	0.0	58.5	0.0	6.1	77.8
WPD_S_Wales	0.0	0.0	1.6	0.0	4.0	1.8	6.4	13.7
WPD_S_West	0.0	4.3	0.0	0.0	7.8	1.8	8.4	22.3
EDFE_LPN	0.0	0.5	10.1	0.0	65.1	0.0	1.0	76.7
EDFE_SPN	0.0	3.8	25.4	0.0	39.6	0.0	23.7	92.6
EDFE_EPN	0.0	0.7	47.1	3.2	48.8	0.0	31.1	130.9
SP_Distribution	0.0	0.8	0.0	0.0	36.8	1.0	2.0	40.5
SP_Manweb	0.0	7.0	2.2	0.0	42.2	0.8	12.3	64.5
SSE_Hydro	0.0	1.8	1.1	0.0	9.0	1.2	1.6	14.7
SSE_Southern	0.0	7.4	7.7	0.0	43.2	2.4	25.0	85.7
Total	**0.0**	**67.9**	**151.4**	**9.3**	**561.0**	**10.3**	**149.0**	**948.9**

Core network investment –Further Details of IP

3.11. The following section provides further details on Ofgem's proposed baseline for each of the core network investment building blocks. A brief discussion of the approach and key issues is provided. A more detailed breakdown by DNO is provided in Appendix 7.

Customer specific demand connections

3.12. An overview of Ofgem's proposed baseline for demand connections is presented in Table 3.4 below. In total across the industry forecast demand connection expenditure makes up 6.0 per cent of forecast core network investment.

Table 3.4 – Initial Proposals – Demand Connections

Demand Connections								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	52.1	25.8	-50.5%	25.8	0.0	0%	-26.3	-50.5%
CN_East	87.1	66.1	-24.2%	66.1	0.0	0%	-21.1	-24.2%
ENW	72.9	37.2	-49.0%	37.2	0.0	0%	-35.7	-49.0%
CE_NEDL	11.0	20.0	81.8%	20.0	0.0	0%	9.0	81.8%
CE_YEDL	9.8	28.7	192.6%	28.7	0.0	0%	18.9	192.6%
WPD_S_Wales	6.0	5.4	-10.0%	5.4	0.0	0%	-0.6	-10.0%
WPD_S_West	10.7	7.8	-27.1%	7.8	0.0	0%	-2.9	-27.1%
EDFE_LPN	5.6	10.5	87.5%	10.5	0.0	0%	4.9	87.5%
EDFE_SPN	57.3	48.1	-16.1%	48.1	0.0	0%	-9.2	-16.1%
EDFE_EPN	30.9	28.8	-6.8%	28.8	0.0	0%	-2.1	-6.8%
SP_Distribution	21.7	16.2	-25.6%	16.2	0.0	0%	-5.5	-25.6%
SP_Manweb	36.1	40.1	11.0%	40.1	0.0	0%	4.0	11.0%
SSE_Hydro	16.5	16.7	1.2%	16.7	0.0	0%	0.2	1.2%
SSE_Southern	24.7	58.8	138.1%	58.8	0.0	0%	34.1	138.1%
Total	**442.5**	**410.1**	**-7.3%**	**410.1**	**0.0**	**0%**	**-32.4**	**-7.3%**

3.13. Demand connections expenditure can be split into two categories:

- expenditure on sole use connection assets which are directly funded by the connecting customer, and
- expenditure on connection assets which could be used by a number of customers. These are subject to the apportionment rule and are only partly funded directly by the connecting customer. These are known as "shared assets".

3.14. As discussed in Chapter 10 of the Incentives and Obligations document, expenditure on sole use connections assets that are directly funded by the connecting customer will be treated as an excluded service during DPCR5. DNOs will be allowed to earn a margin on the direct costs associated with contestable elements of the connections work and, subject to passing a competition test, may then charge an unregulated margin on these services. Only net expenditure relating to shared asset connections is recoverable through the price control.

3.15. Table 5 below shows the DNOs' forecast expenditure and connection volumes for DPCR5. Note that these volumes only refer to connections where there are connection assets subject to the apportionment rule and therefore do not include the volume of sole use connections. The table only includes the shared element of expenditure that is funded through DUoS charges.

Table 3.5 - Split of Demand Connections

DNO £m (07/08 prices)	Total Net Demand Connections		High Volume Lower Cost Connections			Low Volume High Cost Connections		
	DPCR4 actuals	DPCR5 Forecast	DPCR4 actuals	DPCR5 Forecast	DPCR5 Volume	DPCR4 actuals	DPCR5 Forecast	DPCR5 Volume
CN_West	52.1	25.8	44.0	15.8	8989	8.1	10.0	12
CN_East	87.1	66.1	49.0	18.8	14761	38.1	47.3	12
ENW	72.9	37.2	36.9	27.6	1841	36.0	9.6	125
CE_NEDL	11.0	20.0	7.4	11.5	17175	3.6	8.5	17
CE_YEDL	9.8	28.7	7.3	20.2	30581	2.5	8.5	39
WPD_S_Wales	6.0	5.4	2.4	2.4	3999	3.6	3.0	20
WPD_S_West	10.7	7.8	2.7	2.4	5583	8.0	5.4	10
EDFE_LPN	5.6	10.5	0.3	0.0	140	5.3	10.5	23
EDFE_SPN	57.3	48.1	6.7	0.0	433	50.6	48.1	91
EDFE_EPN	30.9	28.8	11.1	0.0	240	19.8	28.8	29
SP_Distribution	21.7	16.2	20.4	5.1	2992	1.3	11.1	7
SP_Manweb	36.1	40.1	19.3	3.9	2984	16.9	36.2	57
SSE_Hydro	16.5	16.7	3.9	6.2	7475	12.6	10.5	1575
SSE_Southern	24.7	58.8	9.6	16.2	32718	15.1	42.6	22
Total	**442.5**	**410.1**	**221.1**	**130.0**	**129911**	**221.4**	**280.1**	**2039**

3.16. The required level of expenditure is highly dependent on the number of connections. Therefore Ofgem's proposed baseline is a composite of an ex ante allowance for larger (low volume high cost) connections and an ex ante baseline which will flex up or down for smaller (high volume lower cost) connections, depending on the volume of actual connections made i.e. a volume driver.

3.17. The volume driver will be applied to 'small scale LV domestic and one-off commercial connections', 'all other LV connections (with only LV work)' and 'LV end connections involving HV work'. All other connections types will be funded through a fixed ex-ante allowance. Further details of how the volume driver will work are provided in Chapter 5.

3.18. The breakdown of forecast connections expenditure was collected for the first time as part of the June FBPQ. We have only been able to undertake a limited review of the DNOs' proposed expenditure, and a summary of our analysis is provided in Appendix 6. For the purposes of modelling expenditure for initial proposals we have used the DNO's forecast expenditure for both the ex ante funded connections and the baseline for those connections subject to a volume driver.

3.19. Updated proposals for demand connection will be made in the Autumn taking account of the:

- current and forecast economic conditions,
- results of benchmarking average cost per connection for connections subject to the volume driver,
- scheme specific reviews of large connection schemes, and
- analysis of the percentage of gross connection assets funded by the DNO due to the apportionment rule.

Diversions

3.20. An overview of Ofgem's proposed baseline for diversions is presented in Table 3.6 below. In total across the industry forecast diversion expenditure makes up 5.2 per cent of forecast core network investment.

Table 3.6 – Initial Proposals – Diversions

Diversions								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	30.7	41.7	35.9%	36.2	5.5	13%	5.5	17.9%
CN_East	42.5	54.8	29.0%	47.4	7.4	13%	4.9	11.6%
ENW	11.1	23.1	109.0%	12.2	10.9	47%	1.1	10.1%
CE_NEDL	15.9	19.7	23.8%	15.2	4.5	23%	-0.7	-4.3%
CE_YEDL	28.2	44.5	58.0%	31.3	13.3	30%	3.1	11.0%
WPD_S_Wales	14.2	14.0	-1.6%	14.0	0.0	0%	-0.2	-1.6%
WPD_S_West	18.0	26.0	44.4%	21.7	4.3	17%	3.7	20.3%
EDFE_LPN	5.7	4.2	-26.3%	3.7	0.5	12%	-2.0	-35.1%
EDFE_SPN	21.8	27.5	26.1%	23.7	3.8	14%	1.9	8.7%
EDFE_EPN	36.8	40.5	10.1%	39.8	0.7	2%	3.0	8.2%
SP_Distribution	12.4	12.8	3.4%	12.0	0.8	6%	-0.4	-3.3%
SP_Manweb	14.8	23.9	61.2%	16.9	7.0	29%	2.1	13.8%
SSE_Hydro	2.2	4.0	81.8%	2.2	1.8	46%	0.0	-1.1%
SSE_Southern	4.9	19.0	287.8%	11.7	7.4	39%	6.8	137.8%
Total	**259.1**	**355.7**	**37.3%**	**287.8**	**67.9**	**19%**	**28.7**	**11.1%**

3.21. Ofgem's proposals for diversions expenditure have been derived from analysis of the following cost categories:

- conversion of wayleaves to easements, injurious affection & related costs,
- diversions due to wayleave terminations, and
- diversions for highways funded as detailed in the National Roads and Street Works Act (NRSWA).

3.22. For the first of these categories some DNOs have made the case for increased costs based on greater activity from predatory agents trying to secure payments to customers with distribution equipment on, or close to, their clients land. Ofgem accepts that this is an issue but considers there is scope for the DNOs to provide more robust challenge and to find more innovative ways to reduce the costs incurred. For these reasons, and to provide incentives for the DNOs to minimise costs in this area, we have limited the increase allowed above DPCR4 costs to 50 per cent.[4]

3.23. For diversion costs due to wayleave terminations and highways, we do not consider the case has been made for increasing costs over and above what has been experienced historically. We also consider that the policy of seeking easements should reduce wayleave terminations in the long-term.

General reinforcement

3.24. An overview of general reinforcement initial proposals is presented in table 3.7 below. In total across the industry forecast general reinforcement expenditure makes up 21.6 percent of forecast core network investment.

Table 3.7 – Initial Proposals – General Reinforcement

General Reinforcement								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	103.2	149.0	44.4%	127.9	21.0	14%	24.7	24.0%
CN_East	111.6	187.3	67.9%	158.8	28.6	15%	47.2	42.3%
ENW	68.0	93.6	37.7%	87.1	6.4	7%	19.2	28.2%
CE_NEDL	61.2	56.4	-8.0%	56.3	0.0	0%	-4.9	-8.0%
CE_YEDL	49.3	62.7	27.2%	62.7	0.0	0%	13.4	27.2%
WPD_S_Wales	22.8	19.9	-12.7%	18.3	1.6	8%	-4.5	-19.7%
WPD_S_West	33.9	20.3	-40.3%	20.3	0.0	0%	-13.7	-40.3%
EDFE_LPN	103.7	209.8	102.3%	199.7	10.1	5%	96.0	92.6%
EDFE_SPN	69.7	107.3	53.9%	81.9	25.4	24%	12.2	17.4%
EDFE_EPN	198.4	246.5	24.2%	199.4	47.1	19%	1.0	0.5%
SP_Distribution	43.9	61.8	40.8%	61.8	0.0	0%	17.9	40.7%
SP_Manweb	37.6	80.0	113.0%	77.8	2.2	3%	40.2	107.1%
SSE_Hydro	22.7	19.5	-14.1%	18.4	1.1	6%	-4.3	-18.9%
SSE_Southern	169.3	150.2	-11.3%	142.5	7.7	5%	-26.8	-15.8%
Total	**1095.2**	**1464.2**	**33.7%**	**1312.8**	**151.4**	**10%**	**217.6**	**19.9%**

3.25. Based on our discussions with the DNOs and the impact of revised load forecasts, DNOs have reduced their forecast investment on general reinforcement from a total of £1612m to £1464m (-£148m or -9 per cent) in the June FBPQs.

3.26. Our initial proposals for general reinforcement were determined by carrying out two separate assessments of costs, split as follows:

- secondary reinforcement (LV and HV), and

[4] Note that on average the DNOs are forecasting an 80 per cent increase.

- primary reinforcement (132kV and EHV).

132kV and EHV Expenditure

3.27. We initially assessed 132kV and EHV expenditure by benchmarking both the amount of capacity being added by the DNO and the cost of the additional capacity. LPN was excluded from the modelling due to its high cost and the complexities associated with central London. EDFE LPN is discussed in more detail in paragraphs 3.37 to 3.39.

3.28. The analysis informed our discussions with the DNOs, rather than being used to directly set the DNOs' baselines. Further information on the model, including initial results, is set out in the May Methodology and Initial Results Paper.

Capacity forecast to be added (Volume)

3.29. During discussions with the DNOs in June we presented them with expenditure relating to a number of schemes where the DNO's own demand forecast did not appear to support the need for additional capacity. These schemes were identified using the model and a review of the DNOs' forecast schemes. In response to our challenge a number of DNOs removed a significant portion of expenditure associated with these schemes from their June FBPQ.

3.30. Although DNOs have reduced their forecast taking account of issues raised by Ofgem, and their updated demand forecasts, we have identified further schemes in their June FBPQs where the demand forecast does not appear to support the need for additional capacity. For initial proposals, these schemes have been removed from the DNOs' forecasts in setting Ofgem's baseline for general reinforcement.

Cost of adding capacity (unit costs)

3.31. The February modelling highlighted a number of DNOs with relatively high costs for added capacity. We have used the model based on February FBPQ data to inform our view on the efficient cost of adding capacity as this data set was subject to considerable quality assurance to ensure comparability of the DNO data and there are significant movement in the underlying data submitted by the DNOs in June that are yet to be explained.. In addition as we have now shared the model and initial results, there is potential for DNOs to have adjusted their submissions to take this into account. Therefore to further support our view we have also used two additional sets of analysis. These are:

- comparing the value of the forecast volumes of primary assets installed for general reinforcement based on the DNOs' own new build unit costs to the value using the industry's median[5] new build unit costs,[6] and

- comparing the DNOs' MEAV based on DNOs' new build unit costs to MEAV based on the industry's median new build unit costs.

3.32. The LRE unit costs methodology has been informed by the work on NLRE unit costs, which also uses the industry median unit cost as the basis for comparisons. Further details of this analysis are provided in Appendix 6.

3.33. All three models (the February model, unit costs based on installed assets, and unit costs based on MEAV) generally highlight the same companies as having high costs: CN West, CN East, ENW, EDFE SPN and EDFE EPN. The results shown in Table 3.8 focus on those DNOs which are higher than the benchmark.[7]

Table 3.8 – Cost modelling reduction percentages

DNO	February Model	Difference between DNO unit costs and median (% of MEAV)			Unit Costs Applied to New Build Volumes
		Substations and Cables	Substations	EHV and 132kV Transformers	
CN_West	-	16.7%	23.0%	27.9%	27.2%
CN_East	-	6.6%	21.5%	27.7%	37.5%
ENW	12.1%	-	-	13.6%	7.6%
CE_NEDL	-	-	-	-	-
CE_YEDL	-	-	-	-	-
WPD_S_Wales	-	-	-	-	-
WPD_S_West	-	-	-	-	-
EDFE_LPN	[redacted]				
EDFE_SPN	33.6%	30.5%	41.0%	59.7%	52.6%
EDFE_EPN	30.3%	31.3%	43.8%	61.4%	42.9%
SP_Distribution	-	3.2%	-	-	[redacted]
SP_Manweb	-	-	-	-	
SSE_Hydro	13.3%	-	-	-	
SSE_Southern	-	-	-	-	

[5] The median excludes EDFE LPN as its costs are significantly higher than the other DNOs due to its operating environment.
[6] SP and SSE did not provide their forecast volume of installed assets as part of the June FPBQ.
[7] The MEAV was modelled using three different sets of asset categories, and all three categories only use primary assets and exclude 66kV assets due to their low volumes for some DNOs. More information is supplied in Appendix 6 about the asset categories included and excluded.

3.34. These five DNOs have higher unit costs compared to the industry. However, due to variations in the type of work that is carried out for LRE, and the fact that the volume of assets installed may not completely relate to the full scheme cost, our initial proposals include a conservative adjustment to LRE unit costs for these five DNOs.

3.35. We have applied a reduction of 2.5 per cent for ENW, 7.5 per cent for CN West and CN East, and a 12.5 per cent reduction for EDFE SPN and EDFE EPN. The relative size of reduction applied to each DNO is a judgement taking account of the relative results of the three benchmarking approaches shown in Table 3.8.

3.36. As part of their response to initial proposals these DNOs will need to provide strong evidence to explain why their costs of capacity are so high. If this is not forthcoming we will consider making further reductions to their forecasts as part of the work for final proposals.

Central London

3.37. EDFE has proposed a series of interrelated projects to reinforce central London which together will cost approximately £170m. We have taken these projects outside of the assessment process explained above. Our consultants, PB Power, have undertaken a detailed review and indicated their support for the engineering justification for the London projects, with the exception of a small number of schemes with expenditure of £10.1m which have been removed from Ofgem's baseline.

3.38. However there are a number of issues which give rise to considerable uncertainty around the final scheme design and timing and therefore the profile of expenditure. The key issues are:

- the complex nature of the work,
- the amount of complex and high value civil work required,
- the large interdependency and sequential nature of a number of schemes, and
- the requirement to obtain suitable land/sites in line with the required time table.

3.39. We are also concerned that our proposed output measures framework will not capture whether these projects have gone ahead. We have therefore proposed an alternative method for the treatment for these projects. These options are outlined in the section on high value projects (paragraphs 3.91 - 3.94).

132kV and EHV Reinforcement Baseline

3.40. Table 9 shows our baselines for 132kV and EHV reinforcement resulting from the combined reductions to unit costs and those resulting from our review of the capacity forecast.

Table 3.9 – 132kV and EHV Reinforcement

General Reinforcement - EHV and 132kV								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	82.4	128.0	55.4%	107.0	21.0	16%	24.6	29.9%
CN_East	85.7	160.8	87.7%	132.3	28.6	18%	46.6	54.4%
ENW	50.3	69.3	37.8%	62.9	6.4	9%	12.6	25.0%
CE_NEDL	42.9	37.1	-13.4%	37.1	0.0	0%	-5.8	-13.4%
CE_YEDL	27.8	40.3	45.0%	40.3	0.0	0%	12.5	45.0%
WPD_S_Wales	15.6	12.6	-19.2%	11.0	1.6	13%	-4.6	-29.5%
WPD_S_West	27.7	13.4	-51.8%	13.4	0.0	0%	-14.4	-51.8%
EDFE_LPN	81.9	179.3	118.9%	169.2	10.1	6%	87.3	106.6%
EDFE_SPN	52.5	88.7	69.0%	63.3	25.4	29%	10.8	20.5%
EDFE_EPN	171.8	209.7	22.1%	162.6	47.1	22%	-9.2	-5.4%
SP_Distribution	20.8	38.3	83.8%	38.3	0.0	0%	17.5	83.8%
SP_Manweb	29.0	71.0	145.2%	68.8	2.2	3%	39.8	137.5%
SSE_Hydro	15.7	13.5	-14.0%	12.4	1.1	8%	-3.3	-21.0%
SSE_Southern	113.6	93.8	-17.4%	92.4	1.4	1%	-21.2	-18.7%
Total	**817.6**	**1155.9**	**41.4%**	**1010.9**	**145.1**	**13%**	**193.2**	**23.6%**

LV and HV Load Related Expenditure

3.41. LV and HV reinforcement was assessed using the DNOs' run-rate expenditure and a weighted industry median as a benchmark, further details on the benchmarking are provided in Appendix 6. In general most DNOs' expenditure on LV and HV was in line with what we would expect from their forecast level of growth and the result of our benchmarking.

3.42. Discussions were held with those DNOs with higher expenditure than expected. Where we have accepted a substantial increase (above that suggested by run-rate analysis) in a DNO's LV and HV expenditure from DPCR4 to DPCR5, sufficient justification has been provided by the DNOs. For example: converting non standard 6.6 kV networks to 11 kV, extensive LV work through network restructuring, and newly identified voltage and thermal constraints.

3.43. Table 3.10 shows our baselines for LV and HV reinforcement resulting from the combined reductions to unit costs and those resulting from our review of the capacity forecast.

Table 3.10 – LV and HV Expenditure

General Reinforcement -LV and HV								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	20.8	20.9	0.6%	20.9	0.0	0%	0.1	0.6%
CN_East	25.9	26.5	2.2%	26.5	0.0	0%	0.6	2.2%
ENW	17.7	24.2	37.2%	24.2	0.0	0%	6.6	37.2%
CE_NEDL	18.4	19.2	4.6%	19.2	0.0	0%	0.8	4.6%
CE_YEDL	21.5	22.4	4.2%	22.4	0.0	0%	0.9	4.2%
WPD_S_Wales	7.2	7.3	1.4%	7.3	0.0	0%	0.1	1.4%
WPD_S_West	6.2	6.9	11.3%	6.9	0.0	0%	0.7	11.3%
EDFE_LPN	21.8	30.5	39.9%	30.5	0.0	0%	8.7	39.9%
EDFE_SPN	17.2	18.6	8.1%	18.6	0.0	0%	1.4	8.1%
EDFE_EPN	26.6	36.8	38.3%	36.8	0.0	0%	10.2	38.3%
SP_Distribution	23.1	23.5	1.9%	23.5	0.0	0%	0.4	1.9%
SP_Manweb	8.6	9.0	4.7%	9.0	0.0	0%	0.4	4.7%
SSE_Hydro	7.0	6.0	-14.3%	6.0	0.0	0%	-1.0	-14.3%
SSE_Southern	55.7	56.4	1.3%	50.1	6.3	11%	-5.6	-10.1%
Total	**277.6**	**308.2**	**11.0%**	**301.9**	**6.3**	**0%**	**24.3**	**8.8%**

Network output measures for general reinforcement

3.44. The DNOs have now provided us with a set of output measures associated with network investment in general reinforcement. In particular, the DNOs have developed a 'Load Index' (LI), which is a framework for collating information on the level of capacity utilisation at specific sites across the distribution network, and for tracking changes in capacity utilisation over time. The LI will be used to inform an assessment of the efficiency of the DNOs' general reinforcement investment decisions over the DPCR5 period.

3.45. The LI is discussed in more detail in Chapter 17 of the Incentives and Obligations Document. In addition, the DNOs' proposed LI profile is provided as an attachment to initial proposals. Between initial and final proposals there will be a process to reconcile the investment allowance for general reinforcement and the associated outputs. Our initial proposals forecasts are contingent on quality supporting output information. If DNOs are unable to adequately quantify and reconcile the outputs associated to their network we may make further reductions to their forecasts or amend the outputs accordingly.

Fault levels

3.46. An overview of our initial proposals for fault level expenditure is presented in Table 3.11 below. In total across the industry forecast fault level expenditure makes up 2.0 percent of forecast core network investment.

Table 3.11 – Initial Proposals – Fault Levels

Fault Levels								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	25.7	-	19.6	6.1	24%	19.6	-
CN_East	13.9	9.4	-33%	9.4	0.0	0%	-4.6	-32.7%
ENW	4.8	2.5	-49%	2.5	0.0	0%	-2.3	-48.7%
CE_NEDL	1.0	8.9	817%	8.9	0.0	0%	8.0	816.8%
CE_YEDL	2.7	14.1	415%	14.1	0.0	0%	11.4	415.2%
WPD_S_Wales	0.0	0.7	-	0.7	0.0	0%	0.7	-
WPD_S_West	0.0	2.9	-	2.9	0.0	0%	2.9	-
EDFE_LPN	4.1	1.3	-68%	1.3	0.0	0%	-2.8	-68.3%
EDFE_SPN	0.6	3.0	400%	3.0	0.0	0%	2.4	400.0%
EDFE_EPN	2.8	28.3	911%	25.1	3.2	11%	22.3	795.2%
SP_Distribution	1.1	17.3	1542%	17.3	0.0	0%	16.3	1541.7%
SP_Manweb	5.9	14.7	149%	14.7	0.0	0%	8.8	149.0%
SSE_Hydro	0.1	2.0	1900%	2.0	0.0	0%	1.9	1900.0%
SSE_Southern	1.2	4.3	258%	4.3	0.0	0%	3.1	258.3%
Total	**38.2**	**135.1**	**253.3%**	**125.8**	**9.3**	**7%**	**87.6**	**229.0%**

3.47. In assessing the appropriate allowances for fault level expenditure we have sought confirmation from the DNOs that the fault level issues being addressed are current. In doing this we have gathered information regarding the current fault level and the fault level rating of the plant affected (whether the issue relates to making or breaking fault level current). As the DNOs have indicated that they do not forecast fault levels as part of their business planning, we have not allowed forecasts of fault levels to contribute to allowances.

3.48. Fault level issues that are currently present on the system require operational and access restrictions to ensure the safety of the public and DNO staff. This is practical in the short term and allows DNOs to ensure safety although in some cases it may be impractical to run the network with permanent operational and access restrictions.

3.49. We are proposing reductions to fault level expenditure for CN West and EDFE EPN. CN West provided adequate information regarding their February FBPQ forecast but have since increased their forecast by £6.1 million. The increase proposed is based on forecast connections and forecast fault levels and we therefore consider the expenditure uncertain and have excluded it from our baseline proposals. Following further questioning EDFE EPN has indicated that some of the schemes forecast in their February FBPQ are now forecast for DPCR6 and a number of others were incorrectly categorised as fault level schemes. EDFE's June FBPQ has taken account of these changes, reducing their forecast by £12.7 million. We propose a further reduction for a scheme based on forecast fault levels and expenditure forecast for the end of DPCR5.

Asset replacement

3.50. An overview of initial proposals for asset replacement is presented in Table 3.12 below. In total across the industry forecast asset replacement expenditure makes up 57.4 percent of forecast core network investment.

Table 3.12 – Initial Proposals – Asset Replacement

Asset Replacement								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	270.2	376.7	39.4%	327.7	49.0	13%	57.5	21.3%
CN_East	191.3	285.3	49%	236.7	48.6	17%	45.4	23.7%
ENW	235.7	349.9	48%	284.1	65.9	19%	48.4	20.5%
CE_NEDL	154.9	279.2	80%	236.6	42.7	15%	81.7	52.7%
CE_YEDL	217.5	330.2	52%	271.7	58.5	18%	54.2	24.9%
WPD_S_Wales	84.5	133.7	58%	129.7	4.0	3%	45.2	53.5%
WPD_S_West	157.9	211.7	34%	204.0	7.8	4%	46.1	29.2%
EDFE_LPN	254.8	275.2	8%	210.1	65.1	24%	-44.7	-17.5%
EDFE_SPN	213.5	286.5	34%	246.9	39.6	14%	33.4	15.6%
EDFE_EPN	267.8	257.1	-4%	208.3	48.8	19%	-59.5	-22.2%
SP_Distribution	222.7	254.8	14%	218.0	36.8	14%	-4.8	-2.1%
SP_Manweb	233.8	333.0	42%	290.8	42.2	13%	57.0	24.4%
SSE_Hydro	118.1	151.2	28%	142.2	9.0	6%	24.1	20.4%
SSE_Southern	293.3	369.3	26%	326.1	43.2	12%	32.8	11.2%
Total	**2916.0**	**3893.9**	**33.5%**	**3332.8**	**561.0**	**14%**	**416.8**	**14.3%**

3.51. The majority of asset replacement expenditure (88.6 per cent) has been assessed through an age based volume modelling and benchmarking of unit costs. The remaining 11.4 per cent consists of expenditure on substation civils (5.5 per cent) and expenditure on assets that are not included within the modelled volumes (5.9 per cent). In most cases these are secondary assets where the volumes of replacement are not separately identified. For some DNOs the non modelled expenditure also includes additional project costs associated with the replacement of modelled volumes.

3.52. Our approach for setting the baseline allowance for these three cost areas is discussed in more detail below. For asset replacement expenditure which is subject to the modelling, we discuss volumes and units costs separately.

3.53. A number of DNOs raised concerns that the age based model was not amenable to determining asset lives and replacement volumes for LV, HV and EHV overhead pole lines (conductor and supports). This is because of the variety of activities included in the scope of works for overhead lines and because the scope of work is different across DNOs, which makes a single volume comparison difficult. A number of DNOs indicated that due to their cyclic approach to refurbishment, age profiles were no longer suitable for age based modelling.

3.54. To address these concerns we have excluded overhead pole lines from the age based model and subjected these forecasts to a detailed bottom up assessment. Forecast expenditure on overhead pole lines account for 22.0 per cent of forecast asset replacement.

Modelled Volumes

3.55. Following the results of our initial modelling which was published in the May document, the DNOs were given the opportunity to provide justification and further supporting evidence for their proposed volumes through bilateral meetings and supplementary questions.

3.56. The type of supporting evidence varied depending on the type of asset. Examples of supporting evidence required in order for Ofgem to accept the DNOs forecast volumes were:

- individual named schemes with supporting narratives highlighting the business case for replacement of high value assets,
- asset specific condition information (DGA results, inspection reports, photographic evidence of poor external condition etc.),
- spreadsheets showing the calculation of heath indices including the underlying input data,
- documentation of poor or worsening performance,
- evidence of known type faults, failure modes and safety issues, and
- reports from specialist external consultants.

3.57. In setting the baseline volumes, where a DNO was able to provide compelling evidence such as that outlined above, the DNO's forecast volume was accepted.[8] Where information was poor or lacking, the DNO's volume has been reduced, with the output of the age based modelling setting the lower limit. Details of the DNO specific volume reductions are provided in Appendix 7.

3.58. Overall the information provided was of good quality in most cases, highlighting the vast improvements that DNOs have made in asset management during DPCR4.

[8] For final proposals this will be dependant on a detailed review of the recently submitted outputs information.

Unit costs benchmarking

3.59. To determine the baseline proposals for the modelled asset replacement, we have multiplied the efficient forecast volumes as determined above by a benchmark unit cost.

3.60. Determining a benchmark cost for asset replacement activities is not straightforward as there are many factors (in addition to efficiency) influencing the actual unit costs, both at the individual project level and average DNO or industry level. These factors include:

- the scope of work including size and rating of equipment,
- assumptions about site specific costs (civil requirements, ground type, indoor/outdoor), and
- assumptions in allocating project costs to individual component assets, including civil costs.

3.61. In determining the benchmark unit costs we have taken account of a number of different sources of information including:

- the unit cost schedules provided by the DNOs in their FBPQs,
- further supporting information provided by DNOs including detailed costings and information on scope of work,
- DNOs' derived unit costs i.e. forecast expenditure divided by volume,
- information contained in scheme papers provided by DNOs,
- an independent view provided by our consultants PB Power, and
- a high level review of the derived unit costs at an industry level for DPCR4.

3.62. We took the industry median corrected for known variances such as known scope differences as our starting point for Ofgem's benchmarked unit costs was. We came to this view after careful review and due consideration to ensure that the median values reflected the scope of work being proposed by the majority of DNOs. The median value was based upon the unit cost schedules provided in the FBPQs, corrected for any differences indentified though the calculation of the implied unit cost. Ofgem's benchmark unit costs are published in Appendix 6, which also includes a summary of the range in DNOs' unit costs and the independent view of our consultants PB Power.

3.63. The industry wide median unit cost was then applied to all DNOs except where specific issues were identified by the DNOs and accepted by Ofgem. These included the additional costs associated with operating within central London (EDFE LPN) and unique switchgear associated with specific network topology in SP Manweb.

3.64. Details of the DNO specific unit cost reductions are provided in Appendix 7.

Overhead Pole Lines

3.65. As discussed above overhead pole line (OHL) volumes were excluded from the age based modelling. We assessed the forecast volumes using detailed bottom up analysis, taking into account the overall asset management strategy for OHLs, the DNOs' supporting narrative, historical volumes and performance information such as fault rates.

3.66. In most cases we accepted the volumes for refurbishment, full rebuilding and replacement of decayed poles (D Poles) as they were appropriately justified.[9]

3.67. In determining baseline expenditure, activity volumes were multiplied by a benchmarked unit cost for comparable activities. Where activities were not comparable, the DNOs' forecast costs were accepted where adequate justification was provided. The activities considered comparable and therefore subject to the benchmark are:

- conductor replacement with minimal pole replacement (ABC assumed for LV),
- conductor replacement with an average level of support replacement (not full rebuild),
- full Rebuild,
- undergrounding, and
- stand alone programmes of D pole replacement.

3.68. Details of the specific DNO reductions are provided in Appendix 7.

Non-Modelled Expenditure

3.69. In undertaking a full reconciliation of the DNOs' forecast – by comparing their forecast at a bottom up level (unit cost multiplied by forecast volume) and their total expenditure forecast – there were a number of DNOs with total forecast expenditure higher than that calculated from the bottom up calculation. In most case this expenditure accounted for less than 5 per cent of asset replacement.

[9] This is dependent on DNOs committing to maintaining as a minimum current fault rates and possibly levels of storm resilience through the network output measures.

3.70. DNOs were asked to provide further justification for this expenditure. Where a DNO has provided inadequate justification for these costs or these costs contain volumes that should have been captured by the model we have made a 20 per cent reduction to these costs.

3.71. EDFE is an outlier with LPN 25 per cent, SPN 13 per cent and EPN 18 per cent of asset replacement forecast expenditure in this category. In a number of cases volumes have been subsequently identified that were not included in the appropriate volume forecasts tables in their FBPQ and were therefore not accessed by the modelling. We have also applied a 20 per cent reduction to these costs.

3.72. Details of the DNO specific reductions are provided in Appendix 7.

Substation Expenditure

3.73. Substation expenditure was separately identified by the DNOs in their forecast and covers general expenditure on substation assets. It mostly consists of spend on substation civils such as buildings and other infrastructure.

3.74. We have assessed these costs by developing a benchmark that takes account of the industry average cost per substation at each voltage level. Due to the high level nature of the analysis and the wide range of different costs included by each DNO, there are some uncertainties with the benchmarked expenditure. Therefore in setting the baseline we have applied equal weightings to the historical level of expenditure, forecast expenditure and the results of the high level benchmarking.

3.75. Details of the DNO specific substation reductions are provided in Appendix 6.

Network output measures for asset replacement

3.76. The DNOs have now provided us with a set of output measures associated with network investment in asset replacement. In particular, DNOs have developed a 'Health Index' (HI), which is a framework for collating information on the health (or condition) of distribution network assets and tracking changes in network health over time. We will use the HI to inform an assessment of the efficiency of the DNOs' asset replacement investment decisions over the DPCR5 period.

3.77. The HI is discussed in more detail in Chapter 17 of the Incentives and Obligations document. In addition, the DNOs' proposed HI profile is provided as an attachment to initial proposals. Between initial and final proposals there will be a process to reconcile the investment allowance for asset replacement and the associated outputs.

3.78. Our initial proposals forecasts are contingent on quality supporting output information. If DNOs are unable to adequately quantify and reconcile the outputs associated to their network we may make further reductions to their forecasts or amend the outputs accordingly.

Operational IT and telecoms

3.79. An overview of initial proposals for operational IT and telecoms (excluding expenditure due to BT21CN) is presented in Table 3.13 below. In total across the industry forecast operational IT and telecoms expenditure makes up 1.6 per cent of forecast core network investment.

Table 3.13 – Initial Proposals – Operational IT and Telecoms

Operational IT and telecoms								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	3.1	2.1	-32.3%	2.1	0.0	0%	-1.0	-32.3%
CN_East	2.9	10.2	253%	10.2	0.0	0%	7.3	252.8%
ENW	12.7	16.4	29%	15.0	1.4	9%	2.3	18.0%
CE_NEDL	0.4	0.4	15%	0.4	0.0	0%	0.1	14.6%
CE_YEDL	3.7	0.4	-88%	0.4	0.0	0%	-3.2	-87.9%
WPD_S_Wales	9.9	8.8	-11%	7.0	1.8	21%	-2.9	-29.5%
WPD_S_West	11.1	12.9	16%	11.1	1.8	14%	0.0	-0.2%
EDFE_LPN	9.0	3.2	-64%	3.2	0.0	0%	-5.8	-64.4%
EDFE_SPN	8.7	2.1	-76%	2.1	0.0	0%	-6.6	-75.9%
EDFE_EPN	3.8	4.4	16%	4.4	0.0	0%	0.6	15.8%
SP_Distribution	7.7	5.2	-33%	4.3	1.0	19%	-3.5	-45.0%
SP_Manweb	5.8	11.3	95%	10.6	0.8	7%	4.7	81.8%
SSE_Hydro	1.9	9.8	416%	8.6	1.2	12%	6.7	352.6%
SSE_Southern	1.7	18.9	1012%	16.5	2.4	13%	14.8	872.1%
Total	**82.4**	**106.2**	**28.8%**	**95.8**	**10.3**	**10%**	**13.4**	**16.3%**

3.80. Expenditure on operational IT and telecoms has been subject to an expert review by PB Power focussing on three areas of investment:

- substation RTUs, marshalling kiosks, receivers,
- communications for switching and monitoring, and
- control centre hardware and software.

3.81. In each of these areas our review has assessed both the scope of works proposed and the unit costs implied and has provided an indication of companies that are outliers with respect to the industry. We have used this information in assessing our initial proposals, applying specific reductions where indicated by the review, and a reduction of 25 per cent on areas where insufficient detail and/or justification was provided in response to further questions.

Legal and safety

3.82. An overview of initial proposals for legal and safety expenditure is presented in Table 14 below. In total across the industry forecast legal and safety expenditure makes up 6.1 percent of forecast core network investment. Ofgem's proposed baseline in no way compromises any DNO's ability to comply with all health and safety requirements and regulations.

3.83. The figures presented exclude expenditure on Rising Mains and Laterals (RML) and Critical National Infrastructure (CNI) which have been reclassified as non core expenditure.

Table 3.14 – Initial Proposals – Legal and Safety

Legal and Safety								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	10.8	17.6	63.3%	14.7	2.9	16%	3.9	36.6%
CN_East	7.2	17.4	141%	14.0	3.5	20%	6.7	92.8%
ENW	16.0	61.2	283%	36.7	24.6	40%	20.7	129.3%
CE_NEDL	8.3	8.7	5%	8.0	0.7	8%	-0.2	-2.9%
CE_YEDL	19.3	23.0	19%	16.9	6.1	26%	-2.4	-12.3%
WPD_S_Wales	1.2	13.9	1054%	7.5	6.4	46%	6.3	524.9%
WPD_S_West	6.7	27.9	319%	19.6	8.4	30%	12.9	193.6%
EDFE_LPN	4.6	3.9	-15%	2.9	1.0	26%	-1.7	-37.0%
EDFE_SPN	12.8	66.7	421%	43.0	23.7	36%	30.2	236.1%
EDFE_EPN	28.6	71.1	149%	40.0	31.1	44%	11.4	39.9%
SP_Distribution	14.2	15.5	9%	13.5	2.0	13%	-0.6	-4.4%
SP_Manweb	29.8	43.7	47%	31.4	12.3	28%	1.6	5.4%
SSE_Hydro	3.5	11.0	214%	9.4	1.6	14%	5.9	169.0%
SSE_Southern	4.7	33.0	602%	8.0	25.0	76%	3.3	70.2%
Total	**167.6**	**414.6**	**147.4%**	**265.6**	**149.0**	**36%**	**98.1**	**58.5%**

3.84. The legal and safety building block includes costs associated with the Electricity Safety Quality and Continuity of Supply Regulations (ESQCR), site security, asbestos clearance, safety equipment, and other areas as specified by the DNOs. The DNOs have forecast expenditure to increase during DPCR5, largely due to amendments to ESQCR specifying safety clearances and increases in site security costs.

3.85. In assessing ESQCR safety clearance costs we have carried out similar benchmarking to that developed for the ESQCR reopener in DPCR4, however we have benchmarked them relative to the mean rather than to the lower quartile.

3.86. We consider this to be appropriate given the increased information regarding these costs in DPCR4 and therefore increased confidence in the robustness of forecasts.

3.87. In line with the approach taken for the ESQCR reopener we have only benchmarked the unit costs of addressing sites with clearance issues as the required volume of works has been subject to detailed survey and agreement with the Health and Safety Executive.

3.88. Only two DNO groups have forecast expenditure relating to maintaining continuity of supply due to the proximity of trees where investment such as installing ABC or undergrounding is more economic than tree cutting. CN West and CN East have forecast a total of £4.8 million, and SSE Southern have forecast £25 million. Following further questioning SSE Southern have presented evidence supporting the installation of Aerial Bundled Conductor (ABC) to maintain safety clearances to climbable trees but did not present a cost benefit analysis for the expenditure on the grounds of continuity this expenditure has therefore been excluded from Ofgem's baseline.

3.89. To assess site security expenditure requirements we have carried out a benchmarking exercise based on the number of substations with EHV or 132kV primary voltage. We have set the baseline in line with the outcome of this benchmarking. For the other areas of legal and safety costs we have carried out a high level review of the DNO forecasts and do not propose any reductions.

High value projects

3.90. In a number of cases DNOs are proposing to undertake large investment projects in excess of £15m, which together total around £0.43bn for DPCR5. Most of these projects relate to large general reinforcement schemes although there are a limited number of asset replacement projects which also exceed £15m. EDFE has proposed a series of interrelated projects to reinforce central London which together will cost £170m. Further details on High value projects are provided in Appendix 6.

3.91. There is some uncertainty over whether these projects will go ahead during DPCR5 or whether issues such as planning consents or resourcing constraints will delay them. We are concerned that our proposed output measures will not fully capture whether these projects have gone ahead, and must ensure that customers only pay where investment has been made.

3.92. There are a number of ways in which we could treat these costs and we seek views on whether we should:

- Provide an ex ante allowance in line with what the company has requested and conduct an ex post review to confirm whether the project went ahead and was carried out efficiently,
- Provide an ex-ante allowance but require the DNOs to provide scheme specific output measures with an ex post review to confirm the outputs are delivered, or
- Provide only part of the required funding up front with an ex post adjustment to allowances during the price control (DPCR5) depending on the actual investment made. We would set a cap in advance on the total amount of funding that we would allow for each project.

3.93. At this stage we have included the DNOs' forecasts within our baseline proposals. This will be reviewed depending on the outcome of this consultation and an update provided in the autumn.

Overview of initial proposals for non-core network investment

3.94. As outlined in the May Methodology and Initial Results Paper we have divided network investment forecasts into "Core" and "Non-core" expenditure. Non-core expenditure is discretionary expenditure, expenditure with higher levels of uncertainty and expenditure with a direct incentive mechanism such as the quality of supply inventive. 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 (HILP and Flooding),
- BT 21st century expenditure, and
- Environmental expenditure (including incremental expenditure on reducing technical losses).

3.95. In addition since the May Methodology and Initial Results Paper we have identified further categories of non-core expenditure which were previously included within the core building block of legal and safety. These are:

- Expenditure on rising mains and laterals, and
- Expenditure on CNI including black start capabilities and physical security.

3.96. As discussed in Chapter 2, Discretionary expenditure has been excluded from the DNOs' forecasts, and therefore our analysis, as it is being separately addressed; further details on discretionary expenditure are provided in Appendix 6. This also applies to a subset of Quality of service (non-IIS) expenditure in relation to worst served customers and a subset of Environmental expenditure on undergrounding in areas of outstanding natural beauty, both of which are subject to a stand alone funding mechanism. For these areas we have not included any expenditure in our baseline proposals and have removed them from the DNOs' DPCR5 forecasts.

3.97. For a number of non-core expenditure items there is currently insufficient clarity regarding the requirement for these costs and we have therefore not determined a baseline at this stage. For the purposes of modelling expenditure of these categories for Initial Proposals we have included the DNOs' forecasts unadjusted pending further review. We intend to provide our initial proposals in these areas in the autumn. Further details are provided in Appendix 6.

3.98. For all other areas of non-core expenditure Ofgem has reviewed the DNOs' forecasts and formed a view of the efficient level of expenditure and included this in our baseline proposals. The treatment of these areas is summarised in the table 3.15 below.

Table 3.15 - Treatment of Non Core Expenditure for Initial Proposals

Building Block	Sub Category	IP Baseline Treatment
Discretionary	N/A	Excluded
Quality of service (IIS)	N/A	Efficiency assessment
Quality of service (non-IIS)	Worst Served Customers	Excluded
Quality of service (non-IIS)	Other	Efficiency assessment
Major system risks	HILP	Unadjusted pending review
Major system risks	Flooding	Efficiency assessment
IT&T	BT21CN	Unadjusted pending review
Legal & Safety	Rising mains and laterals	Unadjusted pending review
Legal & Safety	black start capabilities	Unadjusted pending review
Legal & Safety	CNI security	Unadjusted pending review
Environmental	Undergrounding in AONB	Excluded
Environmental	Technical Losses	Efficiency assessment
Environmental	Other	Efficiency assessment

3.99. The overall position for non-core costs in shown in Table 3.16 including both expenditure subject to modelling assumptions and those subject to an efficiency assessment.

Table 3.16 – Non core network investment

Non Core Network Investment								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	27.6	31.2	13.3%	21.6	9.7	0.3	-6.0	-21.8%
CN_East	27.0	41.6	54.2%	36.2	5.4	13%	9.2	34.0%
ENW	18.7	32.0	71.4%	32.3	-0.2	-1%	13.6	72.6%
CE_NEDL	18.1	12.5	-30.9%	9.9	2.5	20%	-8.1	-45.0%
CE_YEDL	22.0	26.4	20.1%	17.9	8.5	32%	-4.0	-18.4%
WPD_S_Wales	18.2	30.9	70.1%	16.0	14.9	48%	-2.1	-11.7%
WPD_S_West	13.9	39.1	180.9%	15.4	23.7	61%	1.5	10.6%
EDFE_LPN	13.1	72.5	453.4%	63.8	8.7	12%	50.7	386.9%
EDFE_SPN	37.2	61.0	64.0%	45.7	15.3	25%	8.5	22.7%
EDFE_EPN	67.8	99.7	47.1%	77.9	21.8	22%	10.1	14.9%
SP_Distribution	30.8	72.7	136.1%	62.9	9.8	14%	32.1	104.2%
SP_Manweb	25.3	83.5	230.3%	71.6	12.0	14%	46.3	182.9%
SSE_Hydro	12.3	11.2	-8.6%	10.9	0.3	3%	-1.4	-11.2%
SSE_Southern	18.9	41.7	120.5%	23.6	18.0	43%	4.7	25.1%
Total	**350.8**	**656.2**	**87.1%**	**505.7**	**150.5**	**23%**	**154.9**	**44.2%**

3.100. The following sections provide further details on those areas of non-core network investment that have been subject to an efficiency assessment.

Major system risks expenditure – Flooding

3.101. An overview of initial proposals for flooding expenditure is presented in Table 3.17 below.

Table 3.17 – Initial Proposals – Major system risks expenditure – Flooding

Flooding								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.3	2.4	690%	2.0	0.4	18%	1.7	550%
CN_East	0.1	8.4	9781%	6.9	1.5	18%	6.8	8003%
ENW	3.2	7.4	135%	5.9	1.6	21%	2.7	85%
CE_NEDL	0.6	2.5	323%	2.4	0.1	5%	1.8	302%
CE_YEDL	2.1	7.8	269%	6.9	0.8	11%	4.8	229%
WPD_S_Wales	1.0	10.8	991%	8.2	2.6	24%	7.2	729%
WPD_S_West	1.0	6.8	576%	6.1	0.7	10%	5.1	511%
EDFE_LPN	0.5	4.1	720%	3.4	0.7	17%	2.9	577%
EDFE_SPN	0.5	6.0	1100%	5.7	0.3	6%	5.2	1031%
EDFE_EPN	0.6	7.5	1150%	6.6	0.9	12%	6.0	1005%
SP_Distribution	0.3	3.2	942%	2.6	0.5	17%	2.3	765%
SP_Manweb	0.2	11.4	5731%	6.4	4.9	44%	6.2	3193%
SSE_Hydro	0.0	2.7	-	1.3	1.3	50%	1.3	-
SSE_Southern	0.0	9.0	-	4.5	4.5	50%	4.5	-
Total	**10.4**	**89.9**	**768.6%**	**68.9**	**21.0**	**23%**	**58.6**	**566.0%**

3.102. Ofgem's proposals for the expenditure on flood protection have been derived from analysis of the following cost categories:

- forecast expenditure on super grid, bulk supply points and primary substations,
- forecast expenditure on site surveys, and
- forecast expenditure for non site specific costs, such as portable flood defences.

3.103. For the first of these categories we have carried out analysis of the forecast costs by splitting the forecasts into the three respective types of substation. Within these groups we have then divided the sites into those where a site specific survey has been undertaken and those where the forecast costs are based on some form of estimate. We have benchmarked the cost per customer for providing flood protection and given DNOs the minimum of their own forecast and the upper quartile cost per customer benchmark.

3.104. For site surveys we have allowed DNOs the minimum of their own forecast and the DPCR4 average expenditure on site surveys by those DNOs undertaking site surveys in DPCR4.

3.105. For non-site specific flood related expenditure we have allowed DNOs the minimum of their own forecast and DPCR4 average non-site specific expenditure for those DNOs that made expenditure in this area.

QoS (IIS)

3.106. An overview of initial proposals for QoS (IIS) expenditure is presented in Table 3.18 below.

Table 3.18 – Initial Proposals – QoS (IIS)

QoS (IIS)								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	27.2	7.4	-73%	0.0	7.4	100%	-27.2	-100%
CN_East	24.6	2.2	-91%	0.0	2.2	100%	-24.6	-100%
ENW	6.6	0.0	-100%	0.0	0.0	0%	-6.6	-100%
CE_NEDL	15.3	2.4	-84%	0.0	2.4	100%	-15.3	-100%
CE_YEDL	18.1	7.6	-58%	0.0	7.6	100%	-18.1	-100%
WPD_S_Wales	17.0	0.8	-95%	0.0	0.8	100%	-17.0	-100%
WPD_S_West	12.2	0.0	-100%	0.0	0.0	0%	-12.2	-100%
EDFE_LPN	3.6	8.0	122%	0.0	8.0	100%	-3.6	-100%
EDFE_SPN	19.0	15.0	-21%	0.0	15.0	100%	-19.0	-100%
EDFE_EPN	16.4	20.9	27%	0.0	20.9	100%	-16.4	-100%
SP_Distribution	24.7	7.9	-68%	0.0	7.9	100%	-24.7	-100%
SP_Manweb	19.2	5.5	-71%	0.0	5.5	100%	-19.2	-100%
SSE_Hydro	7.4	0.0	-100%	0.0	0.0	0%	-7.4	-100%
SSE_Southern	14.6	17.7	21%	0.0	17.7	100%	-14.6	-100%
Total	**225.8**	**95.5**	**-57.7%**	**0.0**	**95.5**	**100%**	**-225.8**	**-100.0%**

3.107. As set out in the May Methodology and Initial Results paper we believe that the incentive rate should drive DNO decision making about expenditure to improve quality of supply performance in DPCR5. As such we are not proposing to allow any up-front allowances for either CI or CML improvements in DPCR5.

QoS (Non IIS) – Excluding worst served

3.108. An overview of initial proposals for QoS (Non IIS) expenditure is presented in Table 3.19 below.

Table 3.19 – Initial Proposals – QoS (Non IIS)

QoS (Non IIS) – Excluding worst served								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	1.6	-	0.0	1.6	100%	0.0	-
CN_East	1.0	1.6	55%	0.0	1.6	100%	-1.0	-100%
ENW	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_NEDL	0.7	0.0	-100%	0.0	0.0	0%	-0.7	-100%
CE_YEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
WPD_S_Wales	0.0	3.0	-	0.0	3.0	100%	0.0	-
WPD_S_West	0.0	11.3	-	0.0	11.3	100%	0.0	-
EDFE_LPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_SPN	12.2	0.0	-100%	0.0	0.0	0%	-12.2	-100%
EDFE_EPN	41.3	0.0	-100%	0.0	0.0	0%	-41.3	-100%
SP_Distribution	0.0	2.0	-	0.0	2.0	100%	0.0	-
SP_Manweb	0.0	2.0	-	0.0	2.0	100%	0.0	-
SSE_Hydro	0.0	0.0	-	0.0	0.0	0%	0.0	-
SSE_Southern	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**55.2**	**21.4**	**-61.2%**	**0.0**	**21.4**	**100%**	**-55.2**	**-100.0%**

3.109. A number of DNOs put forward proposed expenditure to improve network resilience in DPCR5. Given customer priorities and willingness to pay from our customer research for DPCR5 we have taken the view that no specific expenditure should be allowed for network resilience. We have also taken into account the significant increase in expenditure devoted to tree cutting to comply with the revised ESQCR regulations that were intended to improve network resilience and see this as another reason not to allow additional expenditure in this area.

Environmental

3.110. Environmental expenditure consists of a number of different areas of expenditure including:

- Oil Pollution Mitigation,
- Reduction of SF6 leakage, and
- Noise reduction

3.111. An overview of initial proposals for Environmental expenditure is presented in Table 3.20 below. We have made no reduction to the DNOs forecasts.

Table 3.20 – Initial Proposals – Environmental

Environment								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.1	0.1	-46%	0.1	0.0	0%	0.0	-46%
CN_East	1.3	1.7	25%	1.7	0.0	0%	0.3	25%
ENW	3.8	2.2	-42%	2.2	0.0	0%	-1.6	-42%
CE_NEDL	1.5	1.2	-21%	1.2	0.0	0%	-0.3	-21%
CE_YEDL	1.6	1.9	23%	1.9	0.0	0%	0.4	23%
WPD_S_Wales	0.0	3.3	-	3.3	0.0	0%	3.3	-
WPD_S_West	0.6	7.1	1065%	7.1	0.0	0%	6.5	1065%
EDFE_LPN	4.1	2.5	-39%	2.5	0.0	0%	-1.6	-39%
EDFE_SPN	4.8	6.5	35%	6.5	0.0	0%	1.7	35%
EDFE_EPN	8.9	7.6	-15%	7.6	0.0	0%	-1.3	-15%
SP_Distribution	1.0	5.5	469%	5.5	0.0	0%	4.5	469%
SP_Manweb	2.1	4.5	112%	4.5	0.0	0%	2.4	112%
SSE_Hydro	3.5	1.0	-70%	1.0	0.0	0%	-2.5	-70%
SSE_Southern	1.0	2.0	100%	2.0	0.0	0%	1.0	100%
Total	**34.3**	**47.0**	**37.2%**	**47.0**	**0.0**	**0%**	**12.8**	**37.2%**

Technical Losses

3.112. An overview of the initial proposals for incremental expenditure to reduce losses is presented in Table 3.21 below.

Table 3.21 - Initial Proposals - Incremental expenditure to reduce technical losses

Technical Losses								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast (DNO)	DPCR5 Forecast (Ofgem scenario)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Losses target reduction (MWh)
CN_West	0.0	2.3	2.0	2.0	0.3	12%	2.0	13878
CN_East	0.0	1.4	1.3	1.3	0.1	7%	1.3	8953
ENW	0.2	0.0	1.8	1.8	-1.8	0%	1.6	3982
CE_NEDL	0.0	0.0	0.0	0.0	0.0	0%	0.0	0
CE_YEDL	0.0	0.0	0.0	0.0	0.0	0%	0.0	0
WPD_S_Wales	0.0	8.5	8.5	0.0	8.5	100%	0.0	0
WPD_S_West	0.0	11.8	11.8	0.0	11.8	100%	0.0	0
EDFE_LPN	0.0	0.0	0.0	0.0	0.0	0%	0.0	0
EDFE_SPN	0.0	0.0	0.0	0.0	0.0	0%	0.0	0
EDFE_EPN	0.0	0.0	0.0	0.0	0.0	0%	0.0	0
SP_Distribution	0.0	0.0	5.2	0.6	-0.6	0%	0.6	1132
SP_Manweb	0.0	0.0	4.4	0.5	-0.5	0%	0.5	867
SSE_Hydro	0.0	0.0	4.3	1.0	-1.0	0%	1.0	2499
SSE_Southern	0.0	0.0	14.3	4.1	-4.1	0%	4.1	8198
Total	**0.2**	**24.0**	**53.6**	**11.4**	**12.6**	**53%**	**11.2**	**39509**

3.113. In the FBPQ the DNOs were asked to provided a forecast for the reduction of technical losses in two ways[10]:

1. an unrestricted DNO forecast (DPCR5 Forecast (DNO)), and

2. a forecast against a Ofgem scenario with a defined loss incentive (DPCR5 Forecast (Ofgem scenario).

3.114. For the Ofgem scenario the DNOs were asked to submit their project proposals for reducing technical losses on the basis of a nominal loss incentive value set at £86/MWh, which was calculated using the methodology proposed in the December Policy Paper. For consistency this value was retained for the June FBPQ. However the loss incentive value we have proposed in these initial proposals is £60/MWh, and we have therefore assessed the DNO incremental expenditure to reduce losses on this basis.

3.115. Our assessment has taken account of the present value of the loss incentive over the assumed life of the investment (which we have conservatively set at 20 years). This provides a threshold below which schemes are cost effective. The reduction shown in table 21 comprises those expenditures above this threshold. In general distribution (low voltage) low loss transformers and low voltage cable uprating were found to be cost effective. We note that several schemes fell just above the threshold and that the viability of proposals is dependent on the loading assumptions on which the DNO has based their analysis. High voltage transformers (grid and primary) are not cost effective at £60/MWh.

3.116. The loss targets for the DNOs with incremental expenditures to reduce losses in Final Proposals will be adjusted to factor the loss reductions that a DNO has forecast will occur because of these investments, as shown in table 21 (the losses targets are discussed in more detail in the Incentives and Obligations document). This will serve as an output mechanism to ensure that the DNO undertakes the investment as specified.

3.117. Our policy on losses has been developing up to initial proposals. We will work with the DNOs to finalise their proposed expenditures to reduce losses by September, in advance of final proposals.

Ongoing efficiency and RPEs

3.118. For network investment (both core and non core expenditure) we have not made any specific adjustments for ongoing efficiency and RPEs as we expect the two

[10] The unrestricted DNO forecast has been used in all calculations of the DPCR5 forecast in this document.

factors to cancel each other out over the DPCR5 period. We think that it is reasonable to assume that these unit costs to move in line with inflation (RPI) for the frontier companies during the DPCR5 period. Our evidence base for this assumption is as follows:

- CEPA's analysis for Ofgem forecasted average RPEs of 0.9 per cent a year for capital expenditure.
- First Economics forecasted efficiency improvements of 1 per cent a year for frontier companies in its study for the DNOs.

3.119. Many of the companies have forecast significant real price effects and/or limited scope for efficiency improvements. Given that both the UK and global economy are suffering the most severe recession in living memory we do not think the companies' forecasts for significant RPEs are credible. Even if we return to the positive economic growth in the next twelve months it will take a number of years for the economy to reach the same levels of output achieved before the contraction began. This should mitigate significantly the likelihood of costs moving out of line with underlying inflation. The significant increase in the volume and value of investment the DNOs are undertaking, relative to DPCR4, should also create greater opportunities for economies of scale such as negotiating lower unit costs given increased volumes.

3.120. We have used this overall assumption of movements in line with RPI by constructing our baselines in 2007-08 prices with no adjustment for ongoing efficiencies. We have also not adjusted the cost allowances from the IQI for RPEs relating to network investment.

3.121. We will review the appropriateness of this assumption before Final Proposals taking into account any new emerging data and evidence. This new evidence might result in us adopting a more generous or tougher assumption for DPCR5. For example, we will examine wage settlements in the sector and update forecasts for the economy to assess whether our assumptions are fair to both DNOs and their customers.

Next Steps

Autumn update and Final proposals

3.122. The proposals for network expenditure set out in this document are firm and we think are based on thorough, comprehensive and robust analysis. We do not expect to see significant movements in our assessment of network expenditure in the run up to Final Proposals. However, there are a few areas of costs that we are yet to analyse or where we will update our assessment based on further information from the DNOs. We will carry out our assessment over the coming weeks followed by the publication of an update in the autumn

3.123. The areas we intend to update include:

- demand connections (both the ex ante allowance and the baseline and unit costs for those connections subject to a volume driver)

- general reinforcement and asset replacement in order to take account of the detailed reconciliation of the DNOs' proposed outputs and their forecast expenditure we are currently undertaking. This may result in changes to either the baseline expenditure, the level of outputs the DNO commits to, or both.

- treatment of large projects, and

- expenditure on flood protection.

3.124. The areas where there is insufficient clarity to make firm baseline proposals at this stage which include:

- major system risks expenditure (HILP only),
- BT 21st century expenditure,
- expenditure on rising mains and laterals, and
- expenditure on CNI costs (e.g. preparation for black start).

3.125. Initial proposals for these areas of expenditure will be publish as part of the autumn update.

Link between investment baselines and DNO outputs

3.126. Ofgem's proposed baseline for general reinforcement and asset replacement investment is based on the assumption that all DNOs will provide outputs consistent with the common outputs framework discussed in incentive and obligations chapter, and which fully support their proposed levels of expenditure.

3.127. As the common framework has only been developed and agreed since the publication of the May document DNOs have only very recently provided the level of outputs they commit to deliver as part of the DPCR5 settlement in the common framework. The proposed outputs are published alongside Initial Proposals.

3.128. Our initial proposals forecasts are contingent on good output information. Between Initial and Final Proposals there will be a process to fully reconcile the outputs with the investment allowance for asset replacement and general reinforcement. If DNOs are unable to adequately quantify and reconcile the outputs associated to their forecast network investment expenditure we may make further reductions to their forecasts.

4. Operational activities

Chapter Summary

This chapter gives an overview of the methodologies used in the assessment of operational, developments since the May document and our initial proposals for operational cost baselines.

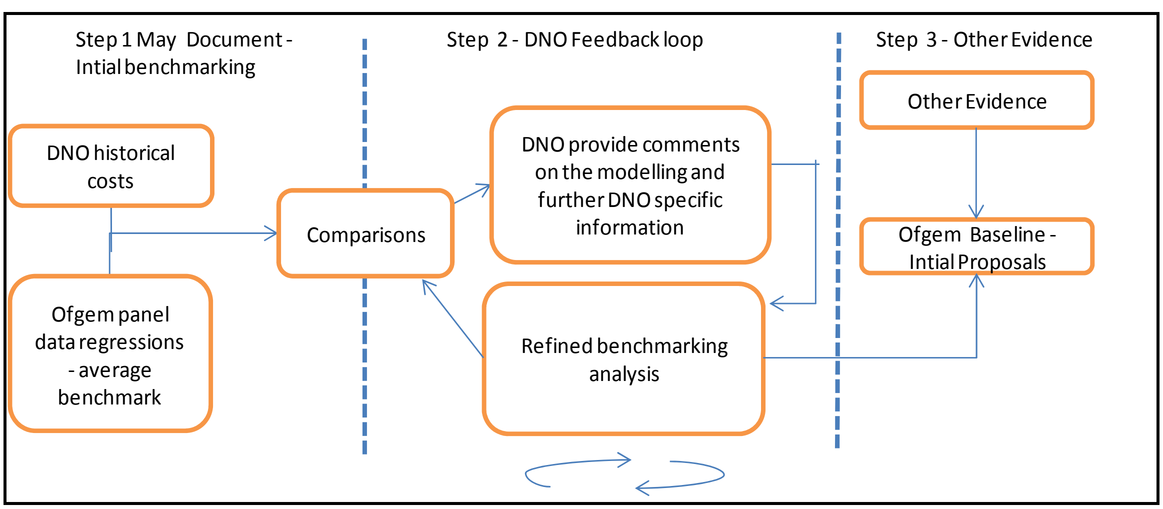
Introduction

4.1. The purpose of this chapter is to provide an update on our overall approach for the assessment of Operational Costs, consisting of Network Operating Costs (NOCs), Indirect Costs (ICs) and Non-Operational Capex (Non-Op). It also provides details of our proposed baselines for Operational Costs for the DPCR5 period for each DNO, prior to applying the IQI.

4.2. Our overall approach to the assessment of efficient costs entails analysis of the DNOs' historical costs reported annually through the Regulatory Reporting Pack (RRP) and the Forecast Business Plan Questionnaire (FBPQ), submitted in June 2009. We have arrived at the baselines for DPCR5 by forming an objective view of the results of all the benchmarking analysis of historical cost and rolling those forward into the DPCR5 period, taking into account changes in the volume of work, ongoing efficiencies and changes in real input prices.

4.3. In May we presented detail on our methodology for assessing Operational Costs and our initial results which formed Step 1 of the methodology outlined below.

Figure 4.1 - Operational Cost methodology overview



4.4. In response to comments on our May document we have developed our methodology significantly and have improved the robustness of our analysis. Since May we have:

- met with the DNOs individually and in industry meetings with the Electricity Networks Association (ENA), to explain and discuss our progress. We have received helpful feedback on our methodology and taken that into account in its development,
- included the 2008-09 cost data submitted in the June FBPQs giving us four years of data to carry out comparisons,
- reached a firm view on how costs such as pensions and related party margins will be treated for the purposes of benchmarking,
- reached a firm view of the functional form of the regression analysis we are undertaking,
- reached a 'minded to' position on DNO specific cost adjustments, and
- reached a better understanding of the key drivers of DNO costs.

4.5. The results of our comparative benchmarking work suggest there are still significant differences in cost efficiency across the DNOs. We have undertaken a core set of analysis and undertaken other analysis to test the robustness of our work. We have tested the impact of:

- excluding various categories of costs from the benchmarking,
- changing the drivers used in the benchmarking, and
- different reporting methodologies between the DNOs, particularly in respect of attributing support costs to customer funded connections compared to costs within the price control.

4.6. We have taken a pragmatic approach to the assessment of costs, particularly where there are apparent but unexplained differences in the level of costs reported by DNOs within a category. Where we have had to determine how to resolve such issues we have stated this clearly in this document.

4.7. The data and analysis included in this chapter do not include Traffic Management Act (TMA) costs. Details of the analysis of TMA costs are included in Chapter 6 of this document.

4.8. All costs reported in this chapter are in 2007-08 prices.

Key developments in our analysis

4.9. We have excluded pension costs from our analysis of Operational Costs. In the forecast and Ofgem's view of baselines in this chapter all costs therefore exclude pensions. As a result the costs will differ from those presented in the overview of DNO actual and forecast costs included in Chapter 2 of this technical document.

4.10. We have concluded that related party margins and most atypical storm related costs (with the exception of one-in-twenty or more severe events) should be included within the benchmarking. The results of the comparative analysis should highlight whether there are any inefficient margins within the DNOs' costs. Further, including or excluding margins has very little impact on the results. We are including costs for one-in-twenty or larger events separately as at DPCR4.

4.11. Further key developments include:

- We have applied a 1 per cent ongoing efficiency assumption to costs in accordance with our analysis detailed in paragraphs 4.93 to 4.95 of this chapter.
- We have decided that the benchmarking will be undertaken on a per DNO basis except for Group 3 costs (Network Policy, Finance and Regulation, HR, CEO, IT and Property Management) that are regressed on a per DNO group basis.
- We have decided to use a logarithmic form of regression in our benchmarking and excluded the use of linear regressions.
- Further details of how we have rolled forward the results of our benchmarking to baseline costs are included in paragraphs 4.79 to 4.86 below.
- Our consultants have completed their analysis of IT and Property Management costs.

4.12. The structure of the rest of this chapter is as follows. The next section sets out an overview of our initial proposals baselines. We then provide an update on our methodology for assessing operational costs. We set out details of the results of our benchmarking and how these results have been rolled forwards to DPCR5. We then discuss the results of our analysis for ongoing efficiency, real input price growth and workforce renewal. Finally we set out further detail of our baselines. Additional technical information is set out in Appendix 5.

Overview of Operational Costs initial proposals

4.13. For the purposes of this paper we have presented our proposals for Operational Cost baselines at a total and disaggregated level by cost category.

4.14. The following tables provide an overview of the DNO forecasts and our initial proposals for Operational Costs:

- Table 1 compares our baseline Operational Costs on a per DNO basis to the DNOs' own forecasts and their expected DPCR4 outturns.
- Table 2 provides the overall performance of the industry disaggregated into the three key areas for Operational Costs of Network Operational Costs, Indirect Costs and Non-Operational capex.
- Table 3 provides the disaggregated analysis on a per DNO basis.

4.15. All of the following tables exclude Real Price Effects (RPEs) and pension costs.

Table 4.1 - Operational Costs baseline initial proposals

	DPCR4	DPCR5 DNO Forecast	Change	increase	Ofgem Baseline	Change to DNO Forecast	Change to DNO Forecast	Change to DPCR4 total	Change to DPCR4 total
	(£m)	(£m)	(£m)	(%)	(£m)	(£m)	(%)	(£m)	(%)
CN West	504	534	30	6%	462	-72	-14%	-42	-8%
CN East	471	483	13	3%	492	9	2%	21	5%
ENW	482	552	70	15%	459	-93	-17%	-23	-5%
CE NEDL	333	328	-5	-1%	315	-13	-4%	-18	-5%
CE YEDL	417	424	7	2%	428	4	1%	11	3%
WPD S Wales	255	296	40	16%	290	-5	-2%	35	14%
WPD S West	373	433	60	16%	386	-47	-11%	13	3%
EDFE LPN	468	472	4	1%	459	-13	-3%	-9	-2%
EDFE SPN	493	501	8	2%	456	-44	-9%	-36	-7%
EDFE EPN	787	831	44	6%	700	-132	-16%	-87	-11%
SP Distribution	429	452	23	5%	374	-78	-17%	-55	-13%
SP Manweb	436	472	36	8%	404	-68	-14%	-32	-7%
SSE Hydro	284	321	37	13%	286	-34	-11%	2	1%
SSE Southern	576	636	60	10%	642	6	1%	66	11%
Total	**6308**	**6735**	**427**	**7%**	**6154**	**-580**	**-9%**	**-153**	**-2%**

4.16. Compared to the DNOs' own forecasts our baselines represent a reduction of £580m for the DPCR5 period representing a 9 per cent reduction overall. The changes range from a 17 per cent reduction for ENW and SP Distribution to a 2 per cent increase over their forecast for CN East.

4.17. At an industry level our initial proposals are a reduction from DPCR4 expenditure of 2 per cent. The results differ between the DNOs from a decrease of 13 per cent over the DPCR4 actuals for SP Distribution to an increase over DPCR4 actuals for WPD S Wales of 14 per cent.

Table 4.2 - Operational Costs baselines by cost area

	DPCR4	DPCR5 DNO Forecast	Change	increase	Ofgem Baseline	Change to DNO Forecast	Change to DNO Forecast	Change to DPCR4 total	Change to DPCR4 total
	(£m)	(£m)	(£m)	(%)	(£m)	(£m)	(%)	(£m)	(%)
Network Operating Costs	2295	2500	205	8.9%	2396	-104	-4%	101	4%
Indirects	3590	3758	168	5%	3306	-452	-12%	-284	-8%
Non-Operational Capex	423	477	55	13%	452	-25	-5%	30	7%
Total	**6308**	**6735**	**427**	**7%**	**6154**	**-580**	**-9%**	**-153**	**-2%**

4.18. Across the industry we are proposing an increase over DPCR4 spend levels for Network Operating Costs of 4 per cent while proposing a reduction for Indirects of 8 per cent. Network Operating costs are going up to cover the costs of additional work, but we are pressing hard on inefficient overheads, which means that overall this area of costs is reducing even though we are allowing for the impact of additional capex.

Table 4.3 - Operational Costs baselines by DNO and cost area compared to DPCR5 forecasts

	Network Operating Costs				Indirects				Non-Operational Capex			
	DPCR5 DNO Forecast	Ofgem Baseline	Change	Change	DPCR5 DNO Forecast	Ofgem Baseline	Change	Change	DPCR5 DNO Forecast	Ofgem Baseline	Change	Change
	(£m)	(£m)	(£m)	(%)	(£m)	(£m)	(£m)	(%)	(£m)	(£m)	(£m)	(%)
CN West	205	181	-24	-12%	320	271	-49	-15%	9	10	1	8%
CN East	218	210	-9	-4%	255	266	11	4%	10	16	6	62%
ENW	174	171	-3	-2%	326	251	-74	-23%	53	37	-16	-30%
CE NEDL	111	109	-2	-2%	194	184	-10	-5%	23	23	-0	-2%
CE YEDL	172	177	4	3%	224	226	3	1%	28	25	-3	-10%
WPD S Wales	116	113	-4	-3%	156	155	-1	-1%	23	23	-0	-1%
WPD S West	170	171	1	1%	209	174	-34	-16%	55	41	-13	-25%
EDFE LPN	173	166	-6	-4%	263	261	-2	-1%	36	32	-4	-10%
EDFE SPN	195	170	-25	-13%	259	245	-14	-6%	47	42	-5	-11%
EDFE EPN	329	300	-29	-9%	431	343	-87	-20%	72	56	-16	-22%
SP Distribution	152	130	-22	-14%	278	220	-59	-21%	22	24	2	11%
SP Manweb	177	154	-23	-13%	274	226	-47	-17%	22	24	2	11%
SSE Hydro	70	82	12	17%	222	170	-52	-24%	29	35	6	22%
SSE Southern	238	263	25	11%	349	315	-34	-10%	50	64	14	29%
Total	**2,500**	**2,396**	**-104**	-4%	**3,758**	**3,306**	**-452**	-12%	**477**	**452**	**-25**	-5%

4.19. Table 3 shows that while the majority of the reductions to DNOs' forecasts are for Indirects there are two DNOs, CN East and CE YEDL, for whom our baselines for Indirects are higher than their forecasts.

4.20. We recognise that it may be unexpected that we would set baselines above the level of costs forecast by the DNOs, however there are circumstances where this is appropriate:

- Where DNOs have achieved particularly good performance in one category by investing in other areas, e.g. where investment in non-operational capex results in better performance for NOCs or Indirects. In such cases we may propose baseline costs above forecast in one area but below forecast in other areas.
- Where a DNO's performance level exceeds what can be expected for the industry as a whole across the different operational cost categories such DNOs are provided some reward for outperformance through the benchmarking.

Methodology Update

4.21. The key to setting allowances for the DNOs for the DPCR5 period is our understanding of the DNOs' expenditure requirements. We use comparative benchmarking analysis to inform our view of the efficiency of the actual costs that each DNO has incurred and then roll forward our view of 'efficient' costs into DPCR5. However, comparative analysis is not appropriate for all costs and for these we rely on other techniques.

4.22. In May we explained that we had appointed consultants to carry out a review of non-operational IT and property costs. This work has now been completed and further detail is set out in Appendix 5.

4.23. We have excluded some other costs from the comparative benchmarking, such as Wayleaves and submarine cables, and have carried out alternative analysis to determine our baselines for these costs.

4.24. We received updated FBPQs from the DNOs in June, which included finalised actual costs for the 2008-09 reporting year. These numbers have been included within our modelling and improved the statistical robustness of our analysis since we now have 56 data points for each cost area (14 DNOs times 4 years) compared to the 42 data points we were using previously.

4.25. The June FBPQ submissions included an additional disaggregation of data between those indirect costs that supported activities within the price control (e.g. costs supporting non-load related expenditure, connections costs subject to the apportionment rule and non-operational capex), and those outside the price control (e.g. sole use connections costs). We have run a version of our analysis using only the cost data identified as funded through the price control but have not had the opportunity to undertake our usual quality assurance work on those numbers. The results of this analysis identified inconsistencies, anomalies and differences in cost allocation across the companies. We have therefore not used this disaggregated data in our benchmarking. We will undertake further quality assurance work on the disaggregated numbers and, if we are satisfied they are suitable we may use them in the autumn update and final proposals. This work may amend the results presented in these proposals.

4.26. This process has resulted in an update to our modelling (step 2) which, along with other evidence (step 3), has fed into our initial proposal baselines for Operational Costs in these proposals.

Inclusion of costs within benchmarking

4.27. For costs to be included within our benchmarking they have to meet certain criteria:

- the DNOs have influence over the cost,
- the activity needs to be undertaken by most of the DNOs, rather than being geographically specific,
- the costs are relatively stable, rather than one-off or 'lumpy',
- provide appropriate coverage of the operational activities, and
- boundary issues with the costs need to be understood.

4.28. Where we have identified costs that do not meet all those criteria, and we are unable to make compensating adjusts, they have been excluded from our benchmarking. In some circumstances these criteria are not mutually consistent and we have had to form a pragmatic judgement on whether to include the costs.

4.29. We recognise that where we exclude cost categories from benchmarking this may potentially skew the overall results. However we think this potential problem is outweighed by the benefits of only applying benchmarks to cost categories which meet the above criteria and are capable of producing robust analysis. We have also tested the impact of alternative inclusions and exclusions on our results.

Benchmarking

4.30. After the May document we undertook a further review of the results and considered what regression techniques we considered the most appropriate. Our view is that the DNOs should be able to obtain returns to scale for both NOCs and Indirect costs and therefore considered that loglog regressions were the most appropriate. The results in the May documents supported this view and provided better correlation of costs and drivers than for linear regressions. We therefore decided to use loglog regressions for benchmarking.

4.31. We have used comparative analysis to inform the level of allowances for our initial proposals. We continue to rely on regression analysis as the key benchmarking technique for assessing relative efficiency of the DNOs' operational expenditure. We have undertaken Data Envelopment Analysis (DEA) as additional checks on the main regression analysis to assist our understanding of the results. Our academic advisor has conducted some analysis using Stochastic Frontier Analysis (SFA) and further details of the findings and limitations of the approach can be found in his Appendix 9. For the reasons cited in the Appendix we do not propose to base our DPCR5 benchmarks for operational activities upon the results from this technique.

4.32. In the May document we provided our reasoning for placing more weight on the results on our regression analysis than those for DEA. We have not received any further evidence and have therefore not changed our view.

4.33. The detailed results of our regression analysis and the results of the DEA and SFA analysis are provided in Appendix 5.

Normalisation Adjustments

4.34. In the May document we highlighted certain issues for which we included, or were considering the inclusion of, normalisation adjustments. These included labour and contractor rates, recognition of indirect costs, and sparsity.

4.35. The normalisation adjustments allow us to compare DNO costs on a more equitable basis. The adjustments are only used to determine the comparative efficiency scores and are not a further adjustment once we have determined the baseline allowances.

4.36. We have undertaken further work to develop our approach to normalisation adjustments and for the purposes of these proposals we have included adjustments for:

- labour and contractor rates,
- non-operational capex,
- recognition of indirect costs,
- cable replacement,
- interconnected network,
- sparsity, and
- urban working.

4.37. Table 4.4 shows the costs for each normalisation adjustment for the year 2008-09.

Table 4.4 - Normalisation adjustments for 2008-09

	Labour and Contractor Rates	Non-operational capex	Recognition of indirect costs	Cable Replacement	Interconnected Network	Sparsity	Urban Working	**Total**
	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	**(£m)**
CN West	4	1	0	6	0	0	-1	**9**
CN East	2	1	0	1	0	0	-0	**3**
UU	1	5	0	13	0	0	-1	**19**
CE NEDL	2	1	0	6	0	0	-0	**9**
CE YEDL	2	2	0	11	0	0	-0	**14**
WPD S Wales	2	2	0	1	0	0	0	**5**
WPD S West	2	5	0	5	0	0	-0	**12**
EDFE LPN	-15	-1	-4	2	0	0	-3	**-21**
EDFE SPN	-4	2	-1	4	0	0	-0	**-0**
EDFE EPN	-3	-1	-6	4	0	0	-1	**-6**
SP Distribution	-0	1	0	13	0	0	-1	**13**
SP Manweb	3	3	0	10	-1	0	-0	**14**
SSE Hydro	1	-1	0	0	0	-2	0	**-1**
SSE Southern	-3	0	0	12	0	0	-1	**9**
Total	**-6**	**20**	**-11**	**89**	**-1**	**-2**	**-9**	**80**

Labour and contractor rates

4.38. In the May document we set out the key issues in relation to adjusting for regional labour and contractor rates and the data that is available. Since May we have received further evidence relating to the use of that data by other regulators and other industries.

4.39. After assessing the information provided to us and our own research we have decided that it is appropriate to include an adjustment for labour and contractor rates across the DNOs based:

- for the labour adjustment, on the Annual Survey of Hours and Earnings (ASHE) data provided by the Office for National Statistics;
- for the contractors adjustment, on the Building Construction Information Service (BCIS) data for construction contracts.

Non-operational capex

4.40. We have provided details of our treatment of non-operational capex in paragraphs 4.118 to 4.121 below.

Recognition of indirect costs

4.41. We recognise that despite the significant advances in cost reporting since DPCR4 there is still potential for costs to be reported differently across the DNOs, depending on their organisational structure and the extent of outsourcing. For example, a company that outsources direct work to contractors will not be required to report the associated indirect costs, such as staff management and vehicles. These will simply be included in the direct costs. Where that outsourcing is on a 'turnkey' basis there are additional indirect costs such as design and project management that will not be reported separately from the contracted direct costs. In such cases the indirect costs reported by the DNO may appear significantly lower than for a DNO that retains more of its direct work in-house and this may skew our comparative analysis results.

4.42. For the May document we included an adjustment for EDFE to account for their introduction of 'alliance contracting' from 2007-08 and stated that we would undertake further work to progress this issue. This effectively reduced their costs that are included in the benchmarking of indirect costs. This adjustment is then reversed out after carrying out the regressions.

4.43. We have asked the DNOs to submit additional information explaining the extent to which contractors undertake indirect activities as part of contracts for work primarily working on the network. At this point that data has not been provided but we will include the results of our analysis for the autumn update paper.

4.44. Until this work is completed we have retained an adjustment for the alliance contracting for EDFE. However, the evidence we have been provided to date suggests that some other DNOs which insource more of their direct activities, may be disadvantaged by the adjustments we have made. We consider it likely therefore that the results in the autumn update will be impacted by the outcome of our ongoing work in this regard.

Cable replacement

4.45. During our analysis we have identified apparent inconsistencies in the reporting of underground cable faults and cable replacement. For the purposes of determining comparative efficiency scores we have therefore included the costs of cable replacement with the costs of underground faults. We have included the length of cable replaced as a secondary driver to the number of faults and run the analysis again with only fault number to assess the impact on the results.

Interconnected network

4.46. Scottish Power have made presentations explaining the impact of costs on their interconnected network in the Manweb area compared to their distribution area in Scotland (SP Distribution). We have been persuaded that the interconnected network does increase costs and have therefore made a normalisation adjustment.

4.47. We have taken account of the overall results for SP Distribution compared to the average for the DNOs and amended the adjustments presented by Scottish Power accordingly.

Sparsity

4.48. Scottish and Southern (SSE) have provided us with a presentation on the additional costs for Operational Costs incurred to service the highlands and islands of Scotland. We have discussed the report and challenged SSE to justify the level of costs reported. We have been satisfied with the responses provided by SSE and have normalised their costs accordingly.

Urban working

4.49. EDFE have made presentations identifying the additional costs of working in an urban environment including specific costs, such as forced ventilation and cable tunnels, and general costs, such as additional overtime for night working etc.

4.50. We have been persuaded that it is appropriate to make adjustments for these costs and have included them in our analysis.

4.51. For specific costs we have made an adjustment for the EDFE LPN network and will undertake further work to determine whether adjustments are required for other DNOs prior to the autumn update. The results are likely to change because of our further work in this area.

4.52. For urban general costs we have developed our methodology based on population densities in local authorities across Great Britain as a proxy for urban networks. We have used the costs provided by EDFE and compared the extent of urban environments to determine adjustments across the DNOs.

Benchmarking techniques and methodology

4.53. We have used a variety of benchmarking techniques to obtain a range of results from which we have applied our judgement to determine the appropriate comparative efficiency scores across the DNOs for those costs. We have consulted our academic advisor to ensure that our methodology is appropriate for the analysis we are undertaking. A review of our approach by our advisor is included in Appendix 8.

4.54. We have continued to carry out our analysis at various levels of disaggregation to enable us to apply specific cost drivers to costs and compare results with more aggregated top-down models. The different levels of disaggregation we have employed are:

- Groups: by combining indirect activities where we can identify common cost drivers,
- Single Group: by combining all indirect activities into a single regression
- Top Down: by combining indirect activities and NOCs into a single regression

4.55. Our assessment of the benchmarking results is that the top down level of disaggregation combines costs at too high a level because of the very different nature of the costs. We consider we can achieve more precision at a slightly more disaggregated level. We recognise that there are some boundaries between the categories of NOCs and Indirects but our view is that these are not significant compared to the difficultly of building cost driver models that robustly explain the costs incurred at such an aggregated level.

4.56. We have continued to run our benchmarking at the top down level but have presented the benchmarking results split between NOCs and Indirects rather than for operational costs as a whole.

Cost Drivers

4.57. In the May document we set out our thinking at that time about the drivers we used for the cost groupings in our benchmarking. Since then we have made significant progress in developing our view of the appropriate drivers for both our core analysis and alternatives.

4.58. We have included secondary drivers where we are of the view that the secondary driver has a material impact on the costs incurred. Table 5 presents the core and alternative drivers for each of the cost groupings included within our benchmarking.

Table 4.5 - Drivers used in benchmarking

Cost Grouping	Core Drivers	Alternative Drivers	
Top-Down	MEAV/ Load & Non-Load Costs	Modern Equivalent Asset Value (MEAV)	
Single Group	Direct Costs/ MEAV	MEAV	
Group 1	MEAV/ Load & Non-Load Costs	Load & Non-Load Costs	MEAV
Group 2	Direct Costs/ MEAV	Direct Costs	MEAV
Group 3	MEAV/ Direct Costs	MEAV	
LV & HV OH	Overhead Faults		
LV & HV UG	UG Faults/ Line Replaced	UG Faults	
I&M	Asset Manhours		
Tree Cutting	Spans Cut/Spans affected		

Driver Weightings

4.59. From our discussions with the DNOs and the evidence they have provided, we have used our judgement to determine a view of which drivers are primary and which are secondary.

4.60. Where we have used multiple drivers we have used statistical techniques to derive the appropriate weightings of those drivers in accordance with the methodology set out in Appendix 5. We have limited the scope of those techniques to set the drivers only to ensure that the weighting of the primary driver is at least 50 per cent. Table 4.6 sets out the weightings we have used for our analysis.

Table 4.6 - Driver weightings

Cost Grouping	Core Drivers	Prime Driver	Secondary Driver
Top-Down	MEAV/ Load & Non-Load Costs	MEAV	Load & Non-Load Costs
		73%	27%
Single Group	Direct Costs/ MEAV	Direct Costs	MEAV
		50%	50%
Group 1	MEAV/ Load & Non-Load Costs	MEAV	Load & Non-Load Costs
		50%	50%
Group 2	Direct Costs/ MEAV	Direct Costs	MEAV
		54%	46%
Group 3	MEAV/ Direct Costs	MEAV	Direct Costs
		100%	0%
LV & HV OH	Overhead Faults		
LV & HV UG	UG Faults/ Line Replaced	UG Faults	Line Replaced
		82%	18%
I&M	Asset Manhours		
Tree Cutting	Spans Cut/Spans affected	Spans Cut	Spans affected
		100%	0%

4.61. For the Single Group and Group 1 the statistical calculation of the weightings suggested a lower weighting for the primary driver than 50 per cent. We have therefore set the weighting for those regressions.

4.62. For Group 3 and for Tree Cutting the statistical calculation of the weightings suggested that the secondary drivers had a zero weighting and we have therefore used MEAV as a single driver.

Benchmarking results

Overall Results

4.63. To determine our view of comparative efficiency scores we have considered the results of our core analysis and a range of alternative analyses we have undertaken to test various assumptions in the core analysis. We have made a judgement about the overall scores taking into account the results of all the analysis rather than selecting any specific analysis.

4.64. As per the May document we present the overall results of our benchmarking as a ratio of the actual costs reported by the DNOs for 2008-09 compared to the modelled costs.

4.65. Table 4.7 shows the overall results of our benchmarking shown for NOCs and Indirects. The results are presented using 'traffic light' formatting to highlight the comparative performance of the DNOs. In the table, scores better than the upper quartile are highlighted in green, those worse that unity are orange and those worse than the lower quartile are highlighted red. Those without a highlight are between the upper quartile and unity.

4.66. Details of the core and alternative results we have used to determine our overall view of comparative efficiency are included in Appendix 5.

Table 4.7 - Overall scores from benchmarking

DNO	NOCs	Indirects
CN West	135%	103%
CN East	101%	85%
ENW	86%	117%
CE NEDL	108%	91%
CE YEDL	111%	79%
WPD S Wales	91%	97%
WPD S West	98%	88%
EDFE LPN	91%	120%
EDFE SPN	114%	105%
EDFE EPN	107%	126%
SP Distribution	112%	98%
SP Manweb	115%	106%
SSE Hydro	59%	104%
SSE Southern	77%	79%
Upper Quartile	**91%**	**89%**
Lower Quartile	**111%**	**106%**

4.67. We consider that our approach is both pragmatic and robust and produces a common sense range between the most efficient and least efficient DNOs but we still have some concerns with the underlying operational cost data we have received from the DNOs. We do not propose to make any significant changes to our approach or methodology. We will continue our work to resolve those areas of concerns including the classifications of costs and apportionment between DNOs within the same group and with the different structures of the DNO groups. Our concerns include:

- The methodology and metrics the DNOs themselves apply to apportion costs between DNOs within the same group. Where those metrics do not coincide with the metrics we have used as drivers of costs there will be a divergence of results across affiliated businesses. We understand that SSE allocates some central costs across both DNOs on a 50:50 basis. When benchmarked using our drivers this will result in notably worse results for SSE Hydro which is a significantly smaller DNO than SSE Southern using any of our usual metrics, although the geographical area is much larger.

- The extent to which DNOs within the same group operate different outsourcing models. CN have informed us that CN East outsource more of their work on a 'turnkey' basis than CN West and therefore the amount of indirects reported for those businesses will differ.

- The extent of unexplained movements in reported costs between 2007-08 and 2008-09.

4.68. One of the reasons ENW has high indirect costs may be that it is the only singleton DNO. We do not consider it appropriate to make a singleton adjustment at DPCR5. Our approach at DPCR4 suggested that such companies should have caught up with the efficiency frontier by DPCR5. This is in line with the approach we applied in GDPCR.

Costs excluded from the benchmarking

4.69. Table 4.8 presents the total costs excluded from the benchmarking in the three categories. Table 4.9 presents a further disaggregation of the 2008-09 Other Costs. We consider it appropriate to present the costs excluded from the benchmarking as we did in the May document:

- costs transferred to Network Investment,
- costs under consultants' review, and
- other costs.

Table 4.8 - Costs excluded from the benchmarking

	Transferred to Network Investment	Consultant Review - IT and Property	Other Costs	Total
	(£m)	(£m)	(£m)	(£m)
CN West	9	12	11	32
CN East	6	10	12	27
ENW	2	17	7	27
CE NEDL	6	10	8	24
CE YEDL	4	11	15	31
WPD S Wales	2	10	6	18
WPD S West	8	11	11	29
EDFE LPN	3	19	14	36
EDFE SPN	8	17	13	38
EDFE EPN	9	25	23	58
SP Distribution	7	16	5	28
SP Manweb	7	15	4	26
SSE Hydro	4	13	8	25
SSE Southern	20	16	12	48
Total	**95**	**202**	**149**	**447**

4.70. These costs represent 34 per cent of the total DNO costs reported for 2008-09. The proportion of costs varies from 28 per cent for ENW to 43 per cent for SSE Hydro.

4.71. As part of the normalisation adjustments we included the average cost of each category of non-operational capex over the period 2005-06 to 2014-15 to the relevant activity costs. The costs transferred to Network Investment are therefore based on average costs over that period rather than the actual 2008-09 costs

4.72. The costs transferred to network investment have been included within the modelling of costs undertaken by our Network Investment team. The results of our consultants' analysis have been used for setting our baseline allowances for the IT and for Property Management.

4.73. For the other costs we have set our baseline allowances on the lower of the average costs reported for the years 2005-06 to 2008-09, with a 1 per cent assumed efficiency saving, and the forecast costs submitted by the DNOs.

Table 4.9 - Other costs excluded from benchmarking disaggregated

	Wayleaves	Submarine Cables	Low Volume High Value Faults	Remote Location Generation	Unmetered Electricity	Terrorism Insurance	Urban Specific	Pressure Assisted Cables	Non QofS Faults	3rd Party Cable Damage Recovery	Dismantlement	Property Rents	Total
	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)	(£m)
CN West	3	-	3	-	-	-	-	1	3	-2	1	1	11
CN East	3	-	3	-	-	-	-	1	4	-2	1	1	12
ENW	2	0	3	-	-	-	-	0	2	-1	0	1	7
CE NEDL	2	-	3	-	-	-	-	1	3	-2	0	1	8
CE YEDL	3	-	5	-	-	-	-	2	8	-3	1	1	15
WPD S Wales	2	-	2	0	1	-	-	-	1	-0	-	1	6
WPD S West	3	-	4	1	1	-	-	-	2	-1	0	1	11
EDFE LPN	1	-	1	-	1	1	1	2	8	-3	-	2	14
EDFE SPN	2	-	4	-	1	0	-	1	7	-4	-	2	13
EDFE EPN	4	-	6	-	1	0	-	2	14	-5	-	3	23
SP Distribution	2	-	1	-	-	-	-	0	3	-2	1	1	5
SP Manweb	3	-	1	-	-	-	-	-	1	-2	-	1	4
SSE Hydro	3	-	2	2	1	-	-	0	0	-0	-	1	8
SSE Southern	4	-	2	-	1	-	-	2	3	-2	-	2	12
Total	35	0	38	3	5	1	1	12	59	-28	4	20	149

4.74. The table shows a very wide range in the values of costs excluded from the benchmarking from £4m for SP Manweb to £23m for EDFE EPN. We have tested the size and proportion of the costs against the results of our benchmarking and found no correlation between them.

Determining our view of efficient costs for 2008-09

4.75. We use the efficiency scores for Network Operating Costs and Indirects to determine the adjustments to each of the DNOs' 2008-09 reported costs and our view of efficient costs for 2008-09. For Network Operating Costs we have adjusted DNOs' costs that are performing worse than the average (greater than 100) down to the average. For DNOs which have scores better than the upper quartile we have moved them to the upper quartile. For DNOs between the average and upper quartile there is no adjustment to their 2008-09 costs.

4.76. For Indirect costs we have adjusted all DNOs' costs in 2008-09 to the upper quartile.

4.77. For Non-Operational Capex the adjustments are the same as for NOCs or Indirects, depending on whether the costs relate to direct or indirect activities (e.g. vehicles are direct but property is indirect) but the adjustments are made to the average cost for the period 2005-06 to 2014-15 because those are the costs included within the benchmarking.

4.78. We have adopted a hybrid approach to NOCs because we do not think it is appropriate to use the upper quartile for all DNOs because of data issues. We do not think it is appropriate to use the frontier level of efficiency as there are still inconsistencies in the cost reporting and FBPQ data and to do so would undermine the robustness of our analysis.

Rolling forward the results to DPCR5

4.79. We have rolled forward the results for 2008-09 into the DPCR5 period including assumptions about the drivers of changes in costs, where appropriate, and of efficiency savings. The following sections detail how we have determined the baseline figures for each of the cost categories.

4.80. For each category we have made an assumption of a 1 per cent efficiency saving per year from 2009-10 to the end of the DPCR5 period. This saving is applied to all NOCs, Indirects and Non-Operational Capex costs included in the benchmarking. For costs excluded from the benchmarking we have applied a slightly different approach to allow for assumed efficiency savings in the DNO forecasts as detailed below.

Network Operating Costs

4.81. For Faults and Inspections and Maintenance included within the benchmarking the baseline costs for 2008-09 are rolled forward using the 1 per cent efficiency saving as explained above, and with an assumed 1 per cent growth term. This growth factor allows for potential additional requirements on DNOs resulting from external factors such as shorter maintenance cycles from identified operational problems with specific assets. This is separate from any costs for Real Price Effects (RPEs) discussed later in this chapter.

4.82. We have calculated tree cutting cost baselines for the whole DPCR5 period using the same analysis as the DPCR4 reopener and apportioned across the DPCR5 years based on the forecasts provided by the DNOs.

Indirect Costs

4.83. To roll forward Indirect costs from the 2008-09 'efficient' costs we have applied the 1 per cent efficiency saving and a growth term calculated using the change in network investment spend over the period to the end of DPCR5.

4.84. In our regression analysis we identified that across the industry indirect costs grew in proportion to increases in capex spending in a ratio of three to one, i.e. for every 3 per cent increase in network investment spend there was a 1 per cent increase in indirect costs. We have used this relationship on an annual basis to determine the growth factor for indirects.

4.85. For DNOs performing worse than the upper quartile level of efficiency in 2008-09 we have capped our baselines at the DNO forecasts.

Non-Operational Capex

4.86. The Non-Operational capex costs are rolled forward as per Network Operating Costs for Small Tools and Equipment, Plant and Machinery and for vehicles. Non-Operational capex costs are rolled forward as per Indirects for IT and Telecoms, Office Equipment and Property.

Workforce renewal

4.87. In Chapter 2, paragraphs 2.42 to 2.44, we set out the DNOs' forecasts for workforce renewal including training and apprentice costs. There are two main factors driving the increase in workforce renewal: the ageing profile of the DNOs' workforce and increasing volumes of capex. We recognise the need for increased expenditure in this area and in assessing the appropriateness of DNOs' forecasts we have asked three main questions:

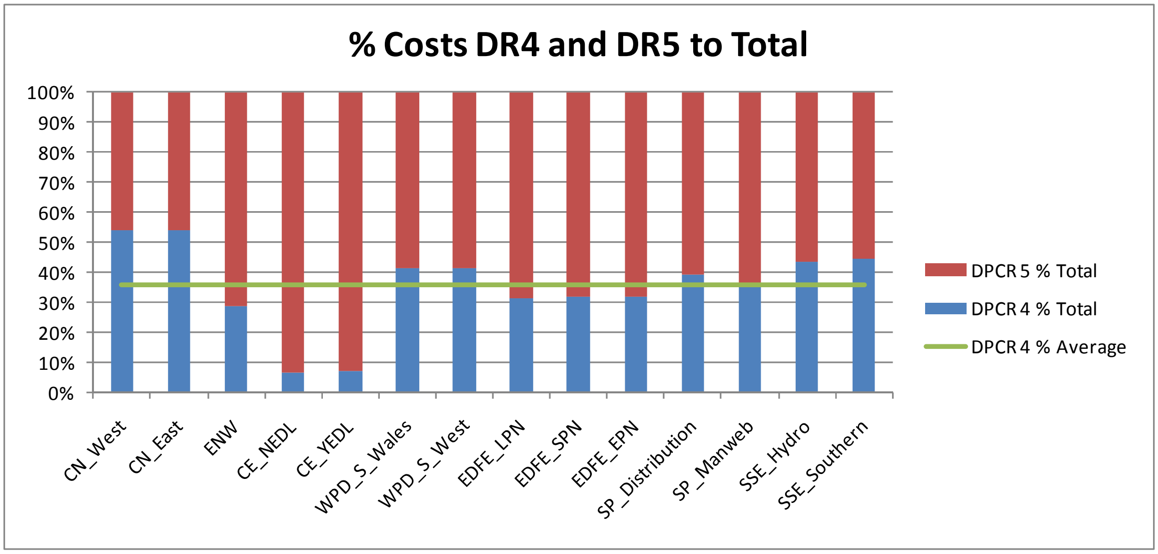
- Is the total level of expenditure appropriate given the current profile of the workforce and future workplans?
- How is the level of expenditure affected by efficiency adjustments we have applied elsewhere? and,
- What proportion of the costs should be funded by customers rather than shareholders?

4.88. We have held meetings with Energy and Utility Skills (EU Skills) to understand the modelling carried out jointly with DNOs, reviewed the DNOs' FBPQ forecasts and asked a number of supplementary questions where we identified particular issues. In general the modelling of workforce renewal has progressed significantly since GDPCR both in terms of the scope of areas of work that have been included and the inclusion of contracting in the modelling. The DNOs have either challenged the assumptions in the EU Skills modelling or carried out their own modelling in parallel. In general the total level of expenditure is reasonably justified but there are adjustments that need to be made to reflect our baselines for operational activities and network investment.

4.89. We have reviewed the relationship between workforce renewal costs associated with growth in activity and the underlying costs for each building block. We have then adjusted the figures to apply efficiency savings to underlying costs.

4.90. The ageing profile of the workforce is an issue that the DNOs have been aware of for a long time and some DNOs have taken greater steps than others during DPCR4 to address it. It is important to ensure that DNOs that have taken earlier steps to manage this issue (and have done so at their shareholders' cost) are not disadvantaged compared to late movers who are seeking larger allowances in DPCR5. Figure 4.2 below highlights the actual costs of workforce renewal to replace leavers in DPCR4 and forecast costs in DPCR5 as a proportion of total expenditure across the two periods. It is clear that both ENW and CE are spending significantly less in DPCR4 as a proportion of the total requirement for DPCR4 and DPCR5.

Figure 4.2 – Workforce renewal costs to manage increasing number of leavers



4.91. Our baselines for workforce renewal are set out in the table below.

Table 4.10 - Workforce renewal baselines

DNO	DNO			Ofgem					
	Growth	Leavers	Total	Growth	Leaver	Total	Adjustment to forecast	Amount included in baselines	Additional cost allowances
CN_West	10.4	7.7	18.1	9.0	7.7	16.8	0.1	4.9	11.9
CN_East	10.4	7.7	18.1	9.1	7.7	16.8	0.1	6.6	10.2
ENW	10.9	15.2	26.2	9.9	13.7	23.7	0.1	3.1	20.5
CE_NEDL	0.0	7.0	7.0	0.0	4.8	4.8	0.3	0.5	4.3
CE_YEDL	0.0	10.5	10.5	0.0	7.3	7.3	0.3	1.2	6.1
WPD_S_Wales	7.0	6.2	13.2	6.5	6.2	12.7	0.0	3.5	9.2
WPD_S_West	10.1	9.0	19.2	9.4	9.0	18.4	0.0	5.5	12.9
EDFE_LPN	1.6	17.1	18.7	1.1	16.1	17.2	0.1	10.6	6.6
EDFE_SPN	2.5	18.8	21.3	2.3	17.8	20.1	0.1	12.0	8.0
EDFE_EPN	2.2	28.9	31.1	1.5	27.4	28.9	0.1	12.5	16.4
SP_Distribution	8.6	9.4	18.1	4.7	9.4	14.2	0.2	3.5	10.7
SP_Manweb	10.5	11.3	21.8	8.8	11.2	20.0	0.1	3.4	16.6
SSE_Hydro	2.2	5.2	7.4	1.6	5.2	6.8	0.1	1.3	5.5
SSE_Southern	4.6	10.0	14.6	3.5	10.0	13.5	0.1	2.7	10.7
Totals	**81.1**	**164.1**	**245.1**	**67.5**	153.6	221.0	0.1	71.4	149.7

4.92. As part of the annual cost reporting requirements DNOs will be required to report on workforce renewal both in terms of the number of FTEs and the costs involved. This will build on our FBPQ tables and will reflect information needed by EU skills in this area to avoid duplication in reporting.

Ongoing efficiency

4.93. The benchmarking presented in this chapter discusses the efficiency improvements that we expect to be achieved by the relatively inefficient companies to catch-up to current industry best practice. In addition to these catch-up improvements we also expect the industry as a whole to make ongoing efficiency improvements during DPCR5. This rate of ongoing efficiency improvements reflects our assumption for the improvements to be made by the relatively low cost DNOs - the frontier companies.

4.94. For initial proposals we are assuming a 1 per cent a year ongoing efficiency trend for the DNOs' operating activities. This assumption has been applied to our baselines for the following categories of expenditure:

- network operating costs,
- network related indirects,
- non-operational capex, and
- business support costs.

4.95. The following evidence fed into our decision for a 1 per cent a year ongoing efficiency assumption:

- A 1 per cent per cent a year trend falls within the range of productivity trends from other sectors that we presented in the May consultation. We have checked that this finding is not changed when these productivity trends are calculated over a more recent period - 1990 to 2005.

- First Economics analysis for the DNOs suggested that productivity improvements should permit the frontier companies to reduce operating expenditure by between 0.7 per cent and 1.4 per cent a year. WPD, one of the frontier companies, have used this analysis and assumed a 1 per cent a year efficiency improvement as part of their business plan submissions.

- When this assumption is combined with our assumption for real price effects it implies that operating expenditure for the frontier companies will move broadly in line with RPI over the DPCR5 period. This approximates to the growth seen by an average sector in the UK economy from the analysis of long-term unit cost trends presented in the May consultation.

Real price effects

4.96. Our assumptions in initial proposals for real price effects are based upon the CEPA study for Ofgem that was published with the May consultation. This report represents the best information that we have available at present on input prices for DPRCR5. However, the evidence presented in the report represents a snapshot at the time of writing. Given the pace of economic developments, it may be appropriate to change these assumptions (up or down) as new evidence emerges between now and Final Proposals.

4.97. CEPA's report provided forecasts for a number of economic scenarios. The report's Scenario 1 seems to match most closely with recent economic developments and with the view of other forecasters. The May consultation provides a summary of the findings in the CEPA study. We set out below how we have used the forecasts from this scenario to form our initial proposals in this area.

4.98. For operational activities, CEPA produced separate RPE forecasts for labour and materials. Expenditure on other items was forecasted to move in line with RPI. The table below sets out these RPE forecasts for labour and materials.

Table 4.11 - CEPA Scenario 1 - RPE forecasts for operating expenditure (per cent per annum)

Year	Labour (general and specialist)	Materials (general)
2008/09	2.2	1.8
2009/10	3.0	2.2
2010/11	1.2	1.3
2011/12	0.9	1.2
2012/13	1.0	1.3
2013/14	1.1	1.3
2014/15	1.1	1.3

4.99. These RPE forecasts were then combined with the weightings in the FBPQ tables "C1 - Cost increase" and "BC1B - Sum Indirects within PC" to create price indices for each component of expenditure. The table below shows how we have matched up the FBPQ cost items with the RPE forecasts.

Table 4.12 - RPEs assumptions for the different cost components

FBPQ cost component	RPE assumption
Labour	CEPA forecasts of RPEs for labour
Pensions	CEPA forecasts of RPEs for labour
Materials	CEPA forecasts of RPEs for materials
Related party margins	Zero RPEs - costs to move in line with RPI
Cost recoveries	Zero RPEs - costs to move in line with RPI
Other	Zero RPEs - costs to move in line with RPI

4.100. The table below summarises the average RPEs for the different types of expenditure by combining CEPA's RPE forecasts with the DNOs' forecasted weights within each expenditure category.

Table 4.13 - Average RPEs by type of expenditure (per cent per annum)

	2008/09-2014/15	2010/11-2014/15
Network operating costs	1.4	1.0
Network related indirects	1.2	0.8
Non-op capex	0.8	0.4
Business support	1.1	0.7
Operational costs total	**1.2**	**0.8**

4.101. The figures presented in the table above are an average taken across all DNOs. As we are using each DNO's individual weights of inputs, the calculated RPEs are not constant across DNOs. For example, for the 2008-09 to 2014-15 period, average operational cost RPEs range from 0.9 per cent to 1.4 per cent a year.

4.102. Table 4.14 below provides the average profile of operational cost RPEs.

Table 4.14 - Operational cost RPEs (per cent per annum)

Year	Overall RPE
2008/09	1.9
2009/10	2.4
2010/11	0.9
2011/12	0.7
2012/13	0.8
2013/14	0.9
2014/15	0.9

4.103. In the responses to the May consultation a number of the DNOs argued that specialist infrastructure workers will be able to achieve above average wage increases as they believe their bargaining power will be stronger than workers in other sectors. We will consider the robustness of this argument before Final Proposals taking into account considerations such as:

- During a period of workforce renewal, employment at the DNOs might be seen as more attractive than during the boom years which could put downward pressure on any wage increases - indeed it may be possible to hire new staff at wage levels lower than in previous years as has occurred in other industries within the economy.

- During a period of increased activity of work it may be possible for the DNOs to negotiate improved terms with their suppliers which might not be reflected in the CEPA forecasts.

- The overall trend in costs must be compatible with observed evidence of higher level price indices. For example, the infrastructure output price index produced by BERR decreased by 4.3 per cent between 2007 and 2008 during a period where RPI increased by 4 per cent - a fall of 8.3 per cent relative to RPI. This might suggest that the infrastructure sector has been hit harder by the recession than other sectors in the economy rather than the opposite.

4.104. We will review the appropriateness of the RPE forecasts presented above before Final Proposals. In particular, we will be reviewing wage settlements to see whether CEPA's labour RPE assumptions remain suitable for the DPCR5 period. Any new information that emerges will be particularly relevant to the assumption for 2009/10, which although not part of DPCR5 still feeds into the cost allowances for the period as the benchmarking analysis has been conducted in 2007/08 prices. We welcome views from respondents on what other information we should review to help form our Final Proposals.

Further Details of Initial Proposals Baselines

4.105. This section provides further details on Ofgem's proposed baselines for Network Operating Costs, Indirect costs and Non-Operational Capex. A brief discussion of the approach and key issues is provided.

Network Operating Costs

4.106. Network Operating Costs have been broken down for our analysis into the following categories:

- Costs included within the benchmarking:
  - LV & HV Underground Faults (including services)
  - LV & HV Overhead Faults (including services)
  - Inspections and Maintenance (I&M) – excluding submarine cables and pressure assisted cables
  - Tree Cutting

- Costs excluded from the benchmarking:
  - Submarine Cable Faults and I&M
  - Pressure Assisted Cable Faults and I&M
  - EHV and 132kv Faults
  - LV and HV Plant
  - Non-Quality of Service Faults
  - Pressure Assisted Cables
  - Remote Location Generation
  - Unmetered Electricity
  - Urban specific cost issues
  - Third party damage recovery
  - Dismantlement

4.107. Table 4.15 presents an overview of our proposed baselines for Network Operating Costs prior to applying the IQI. The figures exclude RPEs, which are added after the IQI is applied.

Table 4.15 – Initial Proposals – Network Operating Costs

	DNO view				Ofgem Baseline	Baseline comparison to Forecast		Baseline comparison to DPCR4	
	DPCR4 expected outturn	DPCR5 Forecast	Change	Change		Change	Change	Change	Change
	(£m)	(£m)	(£m)	(%)	(£m)	(£m)	(%)	(£m)	(%)
CN West	204	205	1	1%	181	-24	-12%	-23	-11%
CN East	224	218	-5	-2%	210	-9	-4%	-14	-6%
ENW	132	174	42	32%	171	-3	-2%	39	29%
CE NEDL	120	111	-10	-8%	109	-2	-2%	-11	-9%
CE YEDL	180	172	-8	-5%	177	4	3%	-4	-2%
WPD S Wales	93	116	23	25%	113	-4	-3%	20	21%
WPD S West	129	170	41	32%	171	1	1%	42	33%
EDFE LPN	178	173	-5	-3%	166	-6	-4%	-12	-7%
EDFE SPN	210	195	-14	-7%	170	-25	-13%	-39	-19%
EDFE EPN	310	329	18	6%	300	-29	-9%	-10	-3%
SP Distribution	125	152	27	22%	130	-22	-14%	5	4%
SP Manweb	141	177	36	26%	154	-23	-13%	13	9%
SSE Hydro	54	70	16	30%	82	12	17%	28	52%
SSE Southern	196	238	42	21%	263	25	11%	67	34%
Total	**2,295**	**2,500**	**205**	**9%**	**2,396**	**-104**	**-4%**	**101**	**4%**

4.108. Compared to the DNOs' own forecasts our baselines represent a reduction of £104m for NOCs for the DPCR5 period representing a 4 per cent reduction overall. The changes range from a 14 per cent reduction for SP Distribution to a 17 per cent increase over their forecast for SSE Hydro.

4.109. When compared to DPCR4 spend, our baselines represent a 4 per cent increase in costs ranging from a 19 per cent reduction for EDFE SPN to a 52 per cent increase for SSE Hydro.

4.110. The baseline figures include an amount for the cost of dealing with a one-in-twenty storm. We have carried the figures forward from the DPCR4 settlement and adjusted for RPI. We are currently considering whether it may be appropriate to apply the same efficiency factor to those costs that we are proposing for the other cost categories. If we do so we would expect the allowances to fall by approximately £10m, less than 0.1 per cent

Indirect Costs

4.111. Indirect costs have been broken down for our analysis into the following categories:

- Costs included within the benchmarking:
  - Group 1 – including the activities of Network Design, Project Management and System Mapping,
  - Group 2 – including the activities of Engineering Management and Clerical Support (EMCS), Control Centre, Call Centre, Stores, Health & Safety and Operational Training,

- o Group 3 – including the activities of Network Policy, IT & Telecoms, Property Management, HR and Non-Operational Training, Finance and Regulation, CEO Etc.

- Costs excluded from the benchmarking:
  - o Wayleaves,
  - o Terrorism Insurance, and
  - o Property Rents

4.112. We recognise that vehicle and transport costs are related to the amount of insourced direct work undertaken. We have therefore allocated these costs across the direct activities, including Network Investment.

4.113. An overview of Ofgem proposed baseline for Indirects is presented in Table 4.16 below.

Table 4.16 – Initial Proposals – Indirect costs

	DNO view				Ofgem Baseline	Baseline comparison to Forecast		Baseline comparison to DPCR4	
	DPCR4 expected outturn	DPCR5 Forecast	Change	Change		Change	Change	Change	Change
	(£m)	(£m)	(£m)	(%)	(£m)	(£m)	(%)	(£m)	(%)
CN West	290	320	30	10%	271	-49	-15%	-19	-7%
CN East	237	255	18	8%	266	11	4%	30	13%
ENW	312	326	14	4%	251	-74	-23%	-60	-19%
CE NEDL	190	194	4	2%	184	-10	-5%	-7	-4%
CE YEDL	215	224	9	4%	226	3	1%	12	5%
WPD S Wales	145	156	11	7%	155	-1	-1%	9	6%
WPD S West	197	209	12	6%	174	-34	-16%	-23	-11%
EDFE LPN	254	263	9	4%	261	-2	-1%	7	3%
EDFE SPN	244	259	15	6%	245	-14	-6%	1	0%
EDFE EPN	404	431	27	7%	343	-87	-20%	-60	-15%
SP Distribution	281	278	-2	-1%	220	-59	-21%	-61	-22%
SP Manweb	279	274	-5	-2%	226	-47	-17%	-52	-19%
SSE Hydro	207	222	15	7%	170	-52	-24%	-37	-18%
SSE Southern	337	349	12	4%	315	-34	-10%	-22	-6%
Total	**3,590**	**3,758**	**168**	**5%**	**3,306**	**-452**	**-12%**	**-284**	**-8%**

4.114. Compared to the DNOs' own forecasts our baselines represent a reduction of £452m for Indirects for the DPCR5 period representing a 12 per cent reduction overall. The changes range from a 24 per cent reduction for SSE Hydro to a 4 per cent increase over their forecast for CN East.

4.115. When compared to DPCR4 spend, our baselines represent a 8 per cent reduction in costs ranging from a 22 per cent reduction for SP Distribution to a 13 per cent increase for CN East.

Consultants' review of IT & Telecoms and Property Management

4.116. We have employed consultants to advise us on the baseline costs we should allow DNOs for the activities of IT & Telecoms (Mouchel) and Property Management

(Drivers Jonas). The results of the work of the consultants' reviews have been used to determine the baselines for those costs.

4.117. We recognise the boundary issues that exist between these activities and other costs categories. We have therefore included these costs in the cost base for determining the relative efficiencies of the DNOs for the Group 3 costs but have used the output from the consultants to determine the appropriate baseline cost allowance for the DPCR5 period.

Non-Operational Capex

4.118. Non-Operational Capex has been reported to Ofgem in the FBPQs under the headings of:

- Small Tools and Equipment
- Plant and Machinery
- Vehicles
- IT and Telecoms
- Office Equipment
- Property

4.119. We have continued discussions with the DNOs in relation to the treatment of non-operational capex expenditure for setting cost baselines.

4.120. We recognise the cyclical nature of non-operational capital expenditure and have therefore taken average figures for the years in which we have data provided on a consistent basis. We have therefore used the average of actual and forecast costs reported for the period 2005-06 to 2014-15.

4.121. We have included all costs within the benchmarking but taken different approaches dependent on the different forms of capital expenditure:

- Small Tools & Equipment and Plant & Machinery have been allocated to direct activities based on the average expenditure for the period 2005-06 to 2014-15 and pro rata to the total labour costs for the direct activities.

- Vehicles have been allocated to the Vehicles and Transport activity based on the average expenditure for the period 2005-06 to 2014-15. The treatment of Vehicles and Transport expenditure is explained in paragraph 4.77 of this document.

- IT & Telecoms non-operational capex costs have been allocated to the IT & Telecoms activity based on the average costs for the period 2005-06 to 2014-15.
- Office Equipment and Property costs have been allocated to the Property Management activity based on the average costs for the period 2005-06 to 2014-15.

Table 4.17 – Initial Proposals – Non-Operational Capex

	DNO view				Ofgem Baseline	Baseline comparison to Forecast		Baseline comparison to DPCR4	
	DPCR4 expected outturn	DPCR5 Forecast	Change	Change		Change	Change	Change	Change
	(£m)	(£m)	(£m)	(%)	(£m)	(£m)	(%)	(£m)	(%)
CN West	10	9	-1	-8%	10	1	8%	-0	-1%
CN East	10	10	-1	-6%	16	6	62%	5	52%
ENW	38	53	14	38%	37	-16	-30%	-1	-3%
CE NEDL	22	23	1	5%	23	-0	-2%	1	3%
CE YEDL	22	28	6	28%	25	-3	-10%	3	15%
WPD S Wales	17	23	6	36%	23	-0	-1%	6	35%
WPD S West	48	55	7	15%	41	-13	-25%	-6	-13%
EDFE LPN	37	36	-1	-2%	32	-4	-10%	-4	-12%
EDFE SPN	39	47	8	20%	42	-5	-11%	3	7%
EDFE EPN	73	72	-1	-2%	56	-16	-22%	-17	-23%
SP Distribution	23	22	-1	-6%	24	2	11%	1	4%
SP Manweb	17	22	5	28%	24	2	11%	7	41%
SSE Hydro	23	29	6	24%	35	6	22%	12	51%
SSE Southern	43	50	7	15%	64	14	29%	21	49%
Total	**423**	**477**	**55**	**13%**	**452**	**-25**	**-5%**	**30**	**7%**

4.122. Compared to the DNOs' own forecasts our baselines represent a reduction of £25m for Non-Operational Capex for the DPCR5 period representing a 5 per cent reduction overall. The changes range from a 30 per cent reduction for ENW and EDFE EPN to a 62 per cent increase over their forecast for CN East.

4.123. When compared to expenditure in DPCR4 our baselines represent a 7 per cent increase in costs ranging from a 23 per cent reduction for EDFE EPN to a 52 per cent increase for CN East.

5. Shetland and Transmission Exit Charges

Chapter summary

This Chapter discusses the issues and our latest thoughts related to the additional costs of meeting electricity demand on Shetland and the latest information on transmission exit charges

Supply on Shetland

Continuation of the current Arrangements

5.1. The island of Shetland is not connected to the main electricity distribution network. Electricity demand on Shetland is met by local generating capacity, which has higher cost than that on the mainland. To ensure that consumers on the island were not disadvantaged during the introduction of the British Electricity Trading Arrangements (BETTA), it was agreed that Scottish Hydro Electric Power Distribution (SHEPD) would administer the electricity supply on the island, so that prices to Shetland's customers remain in line with other customers.

5.2. As the higher costs associated with generation on Shetland became the liability of the distribution business, at the time of the DPCR4 review it was agreed that the cost differential should be recovered from all SHEPD customers. This led to the inclusion of a DPCR4 allowance of £8.2m over the course of the current price control.

5.3. This resulted in the inclusion of the 'Shetland term' in SHEPD's licence, which gives SHEPD additional revenue during the current price control. The DPCR4 allowance and any income received from suppliers by the power station supplying the island is subtracted from the sum of its costs to derive the 'Shetland term'. This is also recovered from all SHEPD customers through a further uplift of its Distribution Use of System (DUoS) charges.

5.4. The Shetland term fluctuates from year to year due to the variability of some of its calculation inputs (e.g. the variability of wholesale market prices, which are used to calculate the income received from suppliers). The cost of this cross-subsidy totalled £15.5m in 2007-08 and according to SHEPD reduced to £10.2m in 2008-09. Of the latter, £8.2m was the allowance assumed in DPCR4 settlement and £2.0m corresponded to surplus costs that were not already recovered through the relevant DPCR4 allowance, which are passed through in accordance with the 'Shetland term'.

5.5. SHEPD is now asking for a continuation of the existing cross-subsidy beyond the current price control period to meet the costs of the existing arrangements. Ofgem accepts the need for a continuation of a mechanism to cover the additional costs of serving the customers on Shetland.

Options for future arrangements

5.6. The Lerwick Power Station (LPS), which currently supplies load on Shetland, was first commissioned in 1955 and is becoming increasingly expensive to operate and maintain. Due to the age and condition of the LPS, SHEPD believes that the arrangements for generating and delivering electricity to customers on Shetland need to be reviewed as part of DPCR5.

5.7. SHEPD and Ofgem are currently discussing options for securing the most efficient future supply on the island. We are currently examining two options: (i) running a competitive tender or (ii) applying an incentive mechanism on SHEPD as Distribution System Operator (DSO). The relevant considerations with respect of each option are examined below.

First Option: competitive tender process

5.8. A competitive process has the potential to ensure that the cost of the cross-subsidy is minimised without, or with minimum levels of, regulatory intervention. Arguably, a tender process is more transparent and will be aimed at delivering a market-based solution.

5.9. At this stage, it is not clear what the level of interest would be in such a tender process. Interest could emerge if the cross subsidy was made available to all competing parties. This could be capped at the level of the cross-subsidy that would result from the implementation of SSE's preferred option for the future supply of the island. Contingency options may need to be developed in the event there is not sufficient interest in the process.

5.10. We anticipate the tender specification might be complex. It will need to cover all potential solutions, including generation, demand and network alternatives. It will also need to provide for some unusual contractual arrangements to ensure the security of supply on the island is maintained. For example, the tender will need to specify requirements for the provision of ancillary services.

5.11. The complexity of the process and the need for proper 'auditability' is likely to increase the procurement costs. At this stage, there is no certainty as to whether the cost of a proper procurement process would be outweighed by the benefits the process may deliver in reducing the cross-subsidy.

5.12. The costs of the tender process would need to be included as part of the respective price control settlement. It might be more efficient for SHEPD, in its role as the DSO, runs the competitive tender. However, we are aware that this alternative may create negative perceptions amongst potential bidders, given that SSE's generation arm may be willing to participate in the process. We are currently exploring options to avoid such perceptions.

Second option: DSO incentive mechanism

5.13. This option will provide immediate clarity for the supply of Shetland. SHEPD has manifested to Ofgem that it is keen to develop solutions on demand reduction and to adopt other management measures. SHEPD has direct experience operating the existing power station on the island and balancing the system on a real-time basis.

5.14. The development of an effective incentive mechanism may also involve substantial effort and cost. Ofgem will need to assess in detail the costs of SHEPD's proposed solutions and design an incentive mechanism which ensures that SHEPD minimises the costs of the resulting cross-subsidy (e.g. through setting an ex-ante allowance and the removal of any pass-through mechanisms). The incentive should ensure that SHEPD actively explores all options to reduce its costs.

5.15. A DSO incentive mechanism will need to provide a clear incentive to outperform. It should also ensure that any benefit is shared with the customers that currently provide the Shetland cross-subsidy.

5.16. The DSO incentive mechanism will need to involve related regulatory reporting.

5.17. Ofgem is keen to receive views on the two options for securing the future supply on Shetland. Our aim is to choose the most efficient and effective option, minimising the cost of the existing cross subsidies and ensuring the security of supply on the island.

Transmission exit charges

5.18. Historically, transmission exit charges have been considered as revenue outside the price control. However, for DPCR5 we are proposing to implement a hybrid framework where the elements of exit charges that a DNO can influence are subject to an incentive, while those that are outside a DNO's control remain as a cost pass-through, outside the price control. We consider that DNOs can influence exit charges arising where they require grid supply point (GSP) reinforcement or new grid supply points (incentivised exit charges).

5.19. Our policy proposals for the treatment of transmission exit charges are described in Chapter 5 of our Incentives and Obligations document.

5.20. In the June FBPQ, we asked the DNOs to provide annual forecasts for transmission exit charges over DPCR5. We asked them to indicate separately the amount of exit charges that is related to assets installed during DPCR5, and to disaggregate these according to the main driver of works (replacement, reinforcement, new GSP). In this way, we can target the proposed incentive specifically to those items of exit charges that a DNO can influence. We also asked the DNOs to provide additional information justifying the need for these works.

5.21. Table 1 below shows the DNO forecasts for total exit charges for each year of DPCR5. It includes exit charges related to items that will be treated as full cost pass-through as well as incentivised exit charges. Table 2 shows the DNO forecasts for incentivised exit charges only.

5.22. We intend to assess the justifications provided by the DNOs for reinforcements and new GSPs they forecast for DPCR5. We will then set an ex ante allowance for the transmission exit charges arising from our assessed efficient level of GSP investment.

5.23. We have not had sufficient time to analyse the information submitted by the DNOs in detail. We have therefore used the DNOs' forecasts as our modelling assumption in initial proposals. We will publish the ex ante allowance for incentivised transmission exit charges in the autumn.

Table 5.1 - DNOs' forecast for total exit charges

	2010-11 (£m)	**2011-12 (£m)**	**2012-13 (£m)**	**2013-14 (£m)**	**2014-15 (£m)**	**Total (£m)**
CN WEST	10.3	10.3	10.9	12.2	19.7	**63.4**
CN EAST	6.7	7.2	7.9	16.6	21.2	**59.6**
ENW	12.2	13.7	13.3	13.1	14.3	**66.6**
CE NEDL	5.1	5.2	5.2	9.9	9.8	**35.2**
CE YEDL	10.0	11.7	10.0	10.0	10.0	**51.7**
WPD S Wales	6.6	6.6	7.2	7.2	7.2	**34.8**
WPD S West	6.6	6.6	7.2	7.2	7.2	**34.8**
EDFE LPN	18.6	24.0	26.8	30.1	37.2	**136.7**
EDFE SPN	8.5	9.4	11.7	18.6	17.7	**65.9**
EDFE EPN	16.2	19.6	22.7	23.7	26.9	**109.1**
SP Distribution	11.8	12.1	12.0	12.4	12.6	**60.9**
SP Manweb	9.2	9.3	9.4	9.4	9.5	**46.8**
SSE Hydro	9.7	11.0	12.4	12.8	13.8	**59.7**
SSE Southern	12.3	12.3	12.3	12.7	12.7	**62.3**
TOTAL	**143.8**	**159.1**	**169.0**	**195.9**	**219.8**	**887.5**

Table 5.2 - DNOs' forecast for incentivised exit charges

	2010-11 (£m)	2011-12 (£m)	2012-13 (£m)	2013-14 (£m)	2014-15 (£m)	Total (£m)
CN WEST	0.0	0.0	0.0	1.0	7.5	**8.5**
CN EAST	0.0	0.0	0.0	8.8	13.3	**22.0**
ENW	0.0	1.0	0.7	0.7	0.7	**3.1**
CE NEDL	0.0	0.0	0.0	4.7	4.7	**9.4**
CE YEDL	0.0	0.0	0.0	0.0	0.0	**0.1**
WPD S Wales	0.0	0.0	0.5	0.5	0.5	**1.5**
WPD S West	0.0	0.0	0.6	0.6	0.6	**1.8**
EDFE LPN	2.8	4.3	5.2	5.5	8.3	**26.1**
EDFE SPN	0.1	0.0	2.0	6.9	7.1	**16.1**
EDFE EPN	2.5	4.0	4.0	2.1	3.9	**16.5**
SP Distribution	0.0	0.2	0.2	0.5	0.5	**1.4**
SP Manweb	0.0	0.0	0.0	0.2	0.2	**0.3**
SSE Hydro	0.6	1.3	2.7	3.1	4.1	**11.8**
SSE Southern	0.0	0.0	0.0	0.0	0.0	**0.0**
TOTAL	**6.0**	**10.9**	**16.0**	**34.6**	**51.3**	**118.7**

6. Managing cost and volume uncertainty

Chapter Summary
This chapter discusses our initial proposals for managing cost and volume uncertainty.

Overview of the changes proposed from the DPCR4 arrangements

6.1. DPCR4 contains a number of mechanisms for managing cost and volume uncertainty. These are:

- All costs within the IQI (regulatory capex) are subject to a sharing factor through the capex rolling incentive. This means that DNOs are currently only exposed to between 29 and 40 per cent of any capex under- or over-spends.
- There are two revenue drivers that were intended to manage demand side risks. These drivers are on units (kWh) distributed and customer numbers.
- There are reopeners for TMA and ESQCR costs.

6.2. For DPCR5 we are proposing to make the following changes:

- A larger basket of costs will be included within the IQI and subject to its sharing factor.
- We are removing the drivers for units distributed and customer numbers. Instead, demand side risks will be captured by:
    - Sole use connections being removed from the price control (excluded service no longer linked to the RAV).
    - Volume drivers on the number of high-volume low-cost connections involving shared assets.
    - A reopener for general reinforcement expenditure and high-cost connections capex involving shared assets.
- A reopener for TMA costs will be preserved as there still remains a great deal of uncertainty over the level and timing of costs.

6.3. As part of the May consultation we raised the possibility of a mechanism for the indexation of allowed revenues with respect to changes in input prices. We have decided that such a mechanism is not required as we believe that the IQI sharing factor provides enough protection and that the DNOs have a good track record of managing input price uncertainty. This view was supported by many of the respondents to the May consultation including some of the DNOs.

6.4. We have reviewed whether there is the need for a more general type of reopener which might capture risks such as a new or changed legal requirement. We have decided that such a reopener is not required as Ofgem must consider its response to such events as part of its statutory duties. If there were a change of law that meant the DNOs were no longer able to finance their activities, then we would consider any reopener request put before us. We do not see the need to reduce our current flexibility of responding to such a request by formalising a new mechanism, and equally we do not want to constrain the DNOs in what they can and cannot include in such a reopener request. We welcome views on whether this decision is appropriate for DPCR5.

Proposed mechanisms for DPCR5

Sole-use connections

6.5. Expenditure on sole-use connections will be treated outside of the main price control as an excluded service no longer linked to the RAV additions. DNOs will have an opportunity to earn a regulated margin on the direct cost of contestable activities. If they pass a competition test they can then earn an unregulated margin. Further details of our proposals in this area are provided in the following sections of Initial Proposals:

- Chapter 10 (Connections incentives and obligations) of the Incentives and Obligations document.
- Chapter 3 (Excluded services) of the Financial Issues document.

Volume drivers on low-cost connections involving shared assets

6.6. For the purpose of these volume drivers we define the low-cost connections involving shared assets to include the following categories of connections from table "LR1 - Demand metered" of the connections part of the FBPQ:

- Small scale LV domestic and one-off commercial.
- All other LV (with only LV work).
- LV end connections involving HV work.

6.7. At present we have not reached a view on the appropriate unit costs to apply to each of these types of connections. For our initial proposals we have applied a modelling assumption based on the DNO forecasts of volumes and unit costs. The unit costs might vary by DNO and also by the type of connection. We will provide our initial proposals for volumes and unit cost baselines as part of the Autumn update.

6.8. At DPCR6 we will make a true-up adjustment to future revenues to reflect the difference between the actual number of connections made and the number currently assumed. This difference will be combined with our unit cost assumptions to calculate the required adjustment to future revenue. This true-up will take into account the workings of the RAV rolling incentive so that expenditure is not double counted. As part of this mechanism we will also true-up for the actual proportion of gross shared connection costs that are funded up front through connection charges so that DNOs do not make a windfall gain or loss from such movements.

6.9. This is intended to work as a revenue driver but with a delay to the revenue adjustments. This is so that customer charges remain predictable over the DPCR5 period. Given the size of expenditure in this area we do not expect this to create any financeability issues for the DNOs. Further details of the mechanics of this scheme will be provided in Final Proposals.

6.10. We welcome views from respondents on whether this proposed mechanism is proportionate to the level of expenditure on these connections and the risk associated with their volumes. In the absence of this mechanism, the volume risk would be split between the DNOs and their customers as determined by the IQI sharing factor.

Load related expenditure reopener

6.11. We propose to include a reopener for load related expenditure associated with general reinforcement and the shared element of high-cost low-volume connections that is DUoS funded.

6.12. We propose that the DNOs could trigger this reopener if they can demonstrate that efficient expenditure in this area has been or is forecasted to be 20 per cent greater than the assumption made by Ofgem in its baseline. The DNOs must demonstrate that this cost difference is due to work volume differences - i.e. demand being greater from their FBPQ forecast or more large one-off connections than expected - rather than unit cost differences which is a risk to be managed by the DNOs. For the general reinforcement side, the DNOs would have to demonstrate using the common framework output measures that the increase in demand above forecasts was responsible for the net increase in reinforcement being undertaken. In deciding whether this threshold has been breached, we will consider whether there have been other parts of the network where there has been less demand than expected and less reinforcement or high-cost connections have occurred than forecasted. The DNOs would need to include any such information in their applications for the reopener. The reopener will consider the net effect of any changes in demand across the network, as it is this net effect which must breach the 20 per cent threshold.

6.13. When Ofgem is satisfied that the relevant criteria have been met, then the price control would be reopened to allow these additional efficient costs to be recovered within the price control period as if they had been included in the original price control allowance.

6.14. We also propose that this reopener would be symmetrical. At DPCR6 Ofgem will carry out a review of expenditure in this area. We will claw back any benefit gained by the DNOs due to demand being significantly lower from that forecasted by the DNOs, if we determine that expenditure in the area is 20 per cent less than our assumption due to this change in demand rather than due to efficiency reasons. In making this assessment will take into account any DSM activities that the DNOs have engaged in. Any avoidance of general reinforcement through DSM would be considered as an efficient offset.

6.15. We will set out the details of this reopener at Final Proposals. We welcome the views of respondents on the workings of this reopener and, in particular, on the appropriate threshold for its operation.

TMA reopener

6.16. For TMA costs we are proposing to include a reopener that will be activated to take account of the timing and level of TMA charges. For initial proposals, we have only allowed permitting costs for the EDFE companies (LPN, SPN and EPN) and SSE Southern as these four areas are impacted by TfL and Kent County Council who are the first movers to introduce the new arrangements. We have taken their volumes, and then benchmarked the unit permit costs and the assumptions for penalties. We then reduced the total expenditure on permitting by 50 per cent to reflect uncertainty over the timing and cost. We will review and update our approach in the Autumn update.

6.17. To date we have found it very difficult to assess the information we have received in the FBPQs from the DNOs and form a robust view of what an appropriate price control assumption would be. This is for the following reasons:

- Some DNOs assume that the transition to a permitting regime will replace the noticing requirement while other DNOs have assumed that the noticing system will remain in place with their associated costs.

- The timing of the introduction of permitting does not tie up with our current understanding. We expect TfL and Kent County Council will implement permitting in 2010-11 with other local authorities not expected to follow suit until the following year at the earliest, depending on the success of the schemes run in London and Kent. A number of DNOs appear to be assuming much quicker implementation of permitting in their regions while others assume that permitting will not be implemented in their region at all.

- The DNOs have forecasted large differences in the average cost of permits between regions - the largest being £171 and the smallest £40 for fault related permits. There are similar differences in the average permitting penalties forecasted by the DNOs - there is a range of £33 to £200.

- There is also a big difference in the penalty rate forecasted by the DNOs. One DNO expects to incur penalties on 1 per cent of fault related permits, whereas another expects to incur penalties on 24 per cent of its permits. There are similar differences in the penalty rates assumed for noticing and inspections.

- We have found it difficult to understand the volumes behind some of the submissions. We have not yet identified a suitable driver that allows volumes to be compared between DNOs.

- There are also some inconsistencies between the FBPQ tables and the commentaries. For example, one DNO assumes a particular average cost of a penalty in the commentary but this is not carried through to the FBPQ table.

6.18. We will continue our work in this area and will publish our preliminary proposals in this area as part of our Autumn update. Between now and then we will work with the DNOs to understand the reasoning behind their submissions. We will analyse any revised figures that we receive from the DNOs and will publish our findings in the Autumn along with the proposed workings of a reopener to account for the uncertainty over the timing and level of TMA charges. We welcome views on whether the GDPCR reopener for TMA costs provides a good template for our DPCR5 Final Proposals.

7. Bringing the package together

Chapter Summary

This chapter brings together the cost analysis presented in Chapters 3 and 4 and our proposals for the IQI to provide an overview of the aggregate cost allowances proposed for DPCR5. It also sets out the work we have carried out to sense check our allowances and make a holistic assessment on costs.

Bringing together the cost assessment and the IQI

7.1. Price control allowances for the majority of network related costs are set through the IQI mechanism. The IQI mechanism combines the Ofgem baselines (presented in Chapters 3 and 4) with the DNOs' FBPQ forecasts to produce an expenditure allowance, an incentive rate that applies to any under- or over-spends, and an additional income term which helps ensure the incentive compatibility of the mechanism. Further details on our proposals for the IQI can be found in Chapter 19 of the Incentives and Obligations document which provides the details of the costs that are subject to the IQI incentive and those which are outside.

7.2. Table 7.1 below presents the inputs for the IQI mechanism. Across the industry as a whole, the Ofgem baselines are 13 per cent lower than the forecasts submitted by the DNOs in their business plans for the DPCR5 period. The difference between the Ofgem baselines and the DNOs' forecasts varies significantly by type of expenditure. The Ofgem baselines are:

- 85 per cent of the industry's forecasts for network investment (in the IQI).
- 98 per cent of the industry's forecasts for network operating costs.
- 82 per cent of the industry's forecasts for closely associated indirects.

Table 7.1 - Inputs to the IQI mechanism - expenditure for the DPCR5 period (£m in 2007-08 prices)

	DNOs' FBPQ forecasts				Ofgem's baselines				
	Network investment	Network operating costs	Closely associated indirects	Total	Network investment	Network operating costs	Closely associated indirects	Total	Ofgem's baselines as a percentage of the
CN West	634.0	209.3	204.3	1047.7	542.5	195.2	165.1	902.9	86%
CN East	626.6	222.2	162.0	1010.9	536.4	223.8	168.6	928.7	92%
ENW	575.0	182.3	174.2	931.4	469.6	178.5	106.7	754.8	81%
CE NEDL	391.2	118.5	101.7	611.4	341.7	120.2	90.8	552.7	90%
CE YEDL	506.9	182.7	116.8	806.4	422.6	186.2	115.2	724.0	90%
WPD S Wales	207.9	116.5	82.7	407.0	182.4	122.4	76.1	380.9	94%
WPD S West	332.2	180.6	115.5	628.3	288.0	186.6	85.5	560.1	89%
EDFE LPN	515.7	172.6	156.8	845.1	431.5	166.1	152.8	750.4	89%
EDFE SPN	558.7	200.1	150.2	909.0	451.9	176.7	130.3	758.9	83%
EDFE EPN	699.6	335.5	268.1	1303.2	548.8	319.8	199.4	1067.9	82%
SP Distribution	391.9	162.3	144.8	699.1	342.9	140.9	107.6	591.3	85%
SP Manweb	551.7	184.2	143.5	879.4	481.1	161.3	108.4	750.8	85%
SSE Hydro	211.4	92.3	111.0	414.8	198.0	101.8	76.7	376.6	91%
SSE Southern	667.5	248.5	211.5	1127.5	569.2	280.3	175.9	1025.4	91%
Total	**6870.4**	**2607.6**	**2143.1**	**11621.1**	**5806.5**	**2559.9**	**1758.8**	**10125.3**	**87%**

7.3. We have applied the IQI at the DNO group level to ensure that all DNOs within a group have the same cost incentives. If this were not the case then the DNOs would be incentivised to allocate more expenditure within their group to the DNO with the weakest incentive strength. Table 2 below provides the results from our application of the IQI at this level. For example, the results for the CN group DNOs are calculated as follows:

- The total CN group forecast is £2,059 million while the Ofgem baseline is £1,832 million giving a group level IQI ratio of 112 per cent.
- At the group level this gives the following IQI outputs:
  - an incentive rate of 44 per cent;
  - an expenditure allowance of £1,888 million; and
  - additional income of £14 million.
- At the DNO level:
  - CN West and CN East both receive the same 44 per cent incentive rate.
  - The expenditure allowance is set 25 per cent of the way between each DNO's baseline and their forecast giving £939 million for CN West and £949 million for CN East.
  - The additional income is allocated between the DNOs using their expenditure allowances as the weights giving them both around £7 million.

Table 7.2 - Outputs from the IQI mechanism (£m in 2007-08 prices)

	DNOs' forecasts	Allowed expenditure	Additional income	Incentive rate
CN West	1047.7	939.1	6.9	44%
CN East	1010.9	949.3	7.0	44%
ENW	931.4	799.0	-8.4	38%
CE NEDL	611.4	567.3	5.3	44%
CE YEDL	806.4	744.6	7.0	44%
WPD S Wales	407.0	387.4	4.2	45%
WPD S West	628.3	577.1	6.3	45%
EDFE LPN	845.1	774.1	-1.9	41%
EDFE SPN	909.0	796.4	-2.0	41%
EDFE EPN	1303.2	1126.8	-2.8	41%
SP Distribution	699.1	618.2	-0.5	41%
SP Manweb	879.4	782.9	-0.7	41%
SSE Hydro	414.8	386.1	4.2	45%
SSE Southern	1127.5	1050.9	11.5	45%

7.4. In addition to these costs within the IQI there are other elements that make up the remainder of price control:

- business support costs;
- non-operational capex;
- the remaining components of the network investment that are not subject to the IQI (e.g. HILP);
- TMA costs; and
- our assumption for real price effects that apply to operational activities.

7.5. Our allowances for costs in these categories are provided in Table 7.3 below.

Table 7.3 - Cost allowances for expenditure outside the IQI (£m in 2007-08 prices)

	Business support costs	Non-operational capex	Network investment (not in the IQI)	TMA costs	RPEs	Total	Allowances as a percentage of the DNOs' forecasts
CN West	91.7	10.1	19.5	4.0	29.9	155.2	55%
CN East	83.9	16.0	33.2	4.3	30.7	168.0	62%
ENW	136.9	37.1	28.3	7.6	32.3	242.1	72%
CE NEDL	81.4	23.0	8.7	1.0	21.9	136.0	63%
CE YEDL	101.5	25.1	16.0	1.6	32.4	176.6	64%
WPD S Wales	68.7	23.0	12.8	1.7	18.8	125.1	78%
WPD S West	72.9	41.1	8.3	2.5	24.6	149.5	69%
EDFE LPN	107.9	32.3	61.3	14.6	35.3	251.2	77%
EDFE SPN	107.6	41.6	39.2	11.2	33.1	232.7	76%
EDFE EPN	124.3	56.2	70.3	21.9	52.3	325.1	69%
SP Distribution	101.2	24.0	56.8	5.0	26.9	213.8	86%
SP Manweb	110.5	23.9	66.6	4.8	29.9	235.8	86%
SSE Hydro	72.7	35.1	8.8	0.9	15.2	132.8	87%
SSE Southern	122.0	63.8	17.5	6.5	36.7	246.4	99%

7.6. Table 7.4 below brings together the expenditure allowances for the all the costs presented above. These costs are grouped by their regulatory treatment:

- All costs that are subject to the equalised incentive are presented as a category. This includes IQI expenditure, network investment that is not in the IQI, and our assumed RPEs on these expenditures. These costs face the IQI incentive strength and are funded as "fast" and "slow" money in a 15:85 split.
- The remaining costs are all expensed and funded in year. These costs face a 100 per cent incentive strength meaning that the DNOs are fully exposed to any under- or over-spends.
- The IQI additional income is presented separately as it not connected with a particular area of expenditure and is added or subtracted from allowed price control revenue.

7.7. Pension costs are not included in this table. For details of our proposals on pensions see Chapter 5 of the Financial Issues document.

Table 7.4 - Total price control allowances (£m in 2007-08 prices)

	Equalised incentive expenditure allowance	Remaining expenditure allowance	IQI additional income	Total	DNOs' FBPQ forecasts (total)	Ofgem's allowances as a percentage of the DNOs' forecasts
CN West	983.6	110.7	6.9	1101.2	1332.4	83%
CN East	1008.4	108.9	7.0	1124.3	1284.0	88%
ENW	847.9	193.2	-8.4	1032.7	1268.2	81%
CE NEDL	591.6	111.8	5.3	708.7	827.9	86%
CE YEDL	784.7	136.4	7.0	928.2	1080.4	86%
WPD S Wales	414.2	98.3	4.2	516.7	567.3	91%
WPD S West	605.1	121.5	6.3	732.9	844.5	87%
EDFE LPN	862.1	163.3	-1.9	1023.4	1173.0	87%
EDFE SPN	859.3	169.8	-2.0	1027.1	1214.3	85%
EDFE EPN	1238.2	213.7	-2.8	1449.0	1776.7	82%
SP Distribution	693.4	138.7	-0.5	831.5	949.0	88%
SP Manweb	870.1	148.6	-0.7	1018.1	1153.2	88%
SSE Hydro	405.6	113.3	4.2	523.1	566.7	92%
SSE Southern	1097.9	199.4	11.5	1308.8	1377.5	95%
Total	**11262.1**	**2027.5**	**36.2**	**13325.8**	**15415.1**	**86%**

7.8. For the industry as a whole, our proposed allowances are 86 per cent of the expenditure forecasted by the DNOs in their business plans. However, there is considerable variation across the DNOs. For example, we propose to allow SSE Southern 95 per cent of their forecasted expenditure, but only 81 per cent for ENW. It should be noted that these numbers are likely to change by Final Proposals because we have not completed our analysis for all areas of expenditure. For initial proposals we have largely included the DNOs' forecasts for these costs.

Holistic assessment of our cost allowances

7.9. In addition to the individual strands of analysis that we have undertaken to form our baselines for operational expenditure and network investment, we have also reviewed and held discussions internally to see how these findings fit with other evidence including:

- How the results from the two areas of analysis fit with each other. For example, are the frontier companies in terms of operational expenditure also the frontier companies in our assessment of network investment? In making this assessment we recognise that there could be cost allocation and substitution considerations - for instance, between network investment and indirects.
- How the results of our analysis fit with the evidence from DPCR4.
- How our results fit with the output information we have received from the DNOs. For example, how embedded are the output measures in the processes adopted by the DNOs to run their businesses.

- How the analysis fits with information we have gained from the DNOs during the cost visits we have engaged in over DPCR4.

7.10. Overall, we consider that the results of our analysis, and the ranking of companies that emerges when all elements are brought together, is consistent with what we know about the DNOs and the way that they run themselves. For example, the two DNO groups that have smallest gap between our proposed allowances and their forecasts - SSE and WPD - both submitted relatively challenging forecasts at DPCR4 and have spent close to their DPCR4 allowances. We have made cost visits to the DNOs over a number of years and the views we have gained from these reinforce the findings from our cost assessment.

7.11. In areas where some of the results might not seem immediately intuitive, we are confident that we have identified key factors that explain these differences and add support to our overall cost assessment. We have also found that the DNOs with high capex unit costs are also the DNOs found to be relatively high cost by our benchmarking of operational activities. This suggests that there are not significant distortions arising from our separate analysis of network investment and operational activities.

7.12. We summarise below some of the key findings from our review in this area to illustrate the way in which we have brought all relevant factors together and applied common sense tests to cross-check the cost allowances per company.

7.13. The results of our operational activity analysis paint different pictures for the two DNOs within the CN group. Our benchmarking found that CN West is relatively high cost while CN East is relatively low cost. We would expect that two companies within the same group would obtain a similar score in our benchmarking and we have looked into this further to see whether there is a common sense explanation, or an anomaly in our methodology. We think the difference can be explained by the different business structures that the DNOs within this group operate under. CN East has engaged in much more turnkey contracts which have resulted in much more work being outsourced at this DNO. This fits with our network investment analysis where CN East generally had higher unit costs for asset replacement. CN East have also allocated more costs to the connections part of the business than CN West. This overall finding fits with the messages we have received from CN who acknowledge that there are significant efficiencies to be made and this is reflected in their business plan forecasts for operational expenditure which helps to explain their relatively good performance under the IQI.

7.14. In a similar way, the results of our benchmarking appear much more favourable to SSE Southern than to the company's Hydro DNO. This can largely be explained by SSE's decision to allocate some categories of indirect costs on a 50:50 basis between the two DNOs. This is despite SSE Southern being a much larger DNO than SSE Hydro.

7.15. WPD South West might initially appear as an outlier in our assessment of its operational activities. Our benchmarking has identified the DNO as being relatively low cost and yet our proposed expenditure allowances are a similar percentage of the expenditure forecast in their business plans as other higher cost DNOs. This is because WPD South West is forecasting large increases in expenditure over the DPCR5 period that exceed our view of how costs will move. On the network investment side, we have found WPD rely more on experienced engineering judgement and make less use of decision support tools than most of the other DNOs. Although this approach differs from the other DNOs, WPD have been to demonstrate to Ofgem that their approach is fit for purpose evidenced by the quality of information they were able to provide.

7.16. For the EDFE group our analysis has suggested that the three DNOs are relatively high cost for both operational activities and network investment. We see this as being a consistent message across the board. Differences in operational efficiency scores may result from the allocation of costs at group level. Where the drivers of cost allocation used by EDFE do not match the drivers we have used the differences will appear as variations in efficiency scores across their DNOs.

7.17. For ENW we have found the DNO to have gone furthest in embracing a condition-based risk management (CBRM) approach based on health indices for asset management, but there are specific areas where they are relatively high cost, including unit costs replacing decayed wood poles. They are also worse than average in terms of the results from our benchmarking of operational activities- this fits with our past analysis of the DNO as part of the ESQCR reopener where we identified them as having high indirect costs relating to tree cutting and clearances. ENW are a singleton DNO and therefore have greater exposure to any fixed costs. We do not propose to make any singleton adjustments in DPCR5. This is in line with our approach at final proposals for DPCR4 where we expected singleton to catch up with the efficiency frontier by DPCR5.

7.18. We have generally found CE to be a well run DNO group which is reflected in their performance in the operational cost benchmarking and their comparatively small increases in forecast increases in operational costs for DPCR5. This is also the case for much of network investment but there are a few areas in asset replacement where we have found them to have high unit costs, which explain much of the difference between our baseline and their forecast in this area. We found CE in general to have a robust approach to asset management supported by well developed policies and long-term plans which corresponds with their general good performance in explaining their volumes of investment. However, CE has submitted particular large forecasts for real input price growth. Differences between our assumptions for RPEs and ongoing account for around half of the total reduction to their network investment submission.

7.19. Our analysis shows SP to be relatively high cost for operational activities but slightly better than average in terms of their network investment plans. Our operational benchmarking has shown SP Distribution to be a lower cost DNO than SP Manweb which fits with both our own and SP's understanding of the differences between the DNOs. Their forecasts have been much more robust that those submitted at DPCR4 which is a positive response to our information quality incentive.

Appendices

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Index – supplementary appendices

Appendix 1 - Consultation Response and Questions

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

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

1.3. Responses should be received by 14 September 2009 and should be sent to:

DPCR5 Response
Electricity Distribution

Ofgem
2nd floor
9 Millbank
London
SW1P 3GE

020 7901 7026
DPCR5.reply@ofgem.gov.uk

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

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

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

Nicola Cocks
Programme Management, Electricity Distribution

9 Millbank, Ofgem, London, SW1P 3GE
020 7901 7036

nicola.cocks@ofgem.gov.uk

CHAPTER: One

Question 1: Have we taken an appropriate approach to assessing costs?
Question 2: What mechanism should be used to fund high value projects?
Question 3: What assumptions do you think we should use for real price effects and ongoing efficiencies for DNOs over the 2010-15 period?
Question 4: Do you agree with our proposed methods for handling uncertainty?
Question 5: Are our proposals for volume drivers on low-cost connections involving shared assets proportionate, i.e. is the mechanism necessary?
Question 6: What is an appropriate materiality threshold for the operation of our proposed load related expenditure reopener?
Question 7: Does the GDPCR reopener for TMA costs provide a good template for our final DPCR5 proposals for these costs?

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.[11]

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[12].

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[13];
- 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.[14]

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[11] entitled "Gas Supply" and "Electricity Supply" respectively.
[12] 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.
[13] 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[15] 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[16] 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.

[14] The Authority may have regard to other descriptions of consumers.
[15] or persons authorised by exemptions to carry on any activity.
[16] 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

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.

Critical National Infrastructure (CNI)

Sites vital to the normal operation of the network , taking account of Home Office and MI5 Protection of Critical National Infrastructure (PCNI) guidance.

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.

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.

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.

G

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.

Grid Supply Point (GSP)

A Grid Supply Point is any point at which electricity is delivered from the National

Electricity Transmission System to the DNO's Distribution System.

H

Health Index (HI)

Tier two network output measure related to network investment on asset replacement. The HI is a framework for collating information on the health (or condition) of distribution network assets and tracking changes in network health over time. The HI will be used to inform an assessment of the efficiency of the DNOs' asset replacement investment decisions over the control period. Under the HI framework, each relevant asset is assigned a ranking of between HI1 and HI5 by the DNO based on an internal condition assessment, and for the forecast period based on the DNO's views about future degradation and potential required intervention.

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.

High Voltage (HV)

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

I

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.

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 Carbon Networks Fund (LCN Fund)

Funding to encourage the DNOs to innovate to deliver the networks we will need for a low carbon economy

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

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.

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.

Traffic Management Act (TMA)

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

Transmission exit charges

Transmission exit charges are charges paid by DNOs to National Grid (in its role as GB System Operator) for the financing and operating costs of the assets that connect the distribution network to the transmission network (the transmission exit point).

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

Worst Served Customers (WSC)

Customer experiencing greater than or equal to five higher voltage interruptions on average over a three year period i.e. 15 or more over three years. Additional caveat of a minimum of three higher voltage interruptions in each year.

Appendix 4 - Feedback Questionnaire

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

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

1.2. Please send your comments to:

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