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Electricity Distribution Price Control Review Initial Proposals - Allowed Revenues and Financial Issues

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

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

The current price control expires on 31 March 2010 and Ofgem is now undertaking a Distribution Price Control Review (DPCR5) to set the controls for 2010-2015. This is one of a series of technical papers that accompany the initial proposals document also published today. It focuses on financial issues: cost of capital, financeability, tax, pensions, excluded services, regulatory asset values (RAV) and depreciation. It sets out our proposals for total revenue allowances for each DNO and explains how we intend to use the return on regulatory equity (RORE) measure in the lead up to Final Proposals. too

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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

This document sets out our in greater detail our initial proposals for the distribution price control review (DPCR5) in the policy areas collectively known as financial issues. It also sets out our proposed overall revenue allowances for each of the 14 DNOs. The issues covered include:

- **Chapter 1: Cost of capital.** In setting price controls we assume that some costs are recovered over a period of time, especially expenditure expected to provide benefits over several years. This requires the DNO to obtain financing for costs not recovered immediately and so our allowed revenues need to allow a reasonable return to the providers of that debt and equity finance. We typically describe this return as being the cost of capital. We have commissioned a report from consultants PricewaterhouseCoopers (PwC), who have proposed a range of values. In all previous price controls, we have set a common cost of capital for all businesses with no specific provision to reopen that cost of capital during the period of the control. There is a general disapplication provision in all price controls where a company can make a case that the price control should be re-opened and reset. A company could seek to use this provision to reopen the cost of capital but in considering a case made by the company using this provision we would be able to look at all aspects of the settlement and not focus solely on the cost of capital. Several respondents to earlier documents (and previous price control settlements) have suggested we should introduce a specific "debt trigger". This could take a variety of forms from a mechanistic mechanism that linked the allowed cost of debt to observed market information to a mechanism that allowed companies or Ofgem to trigger a review of the cost of debt in defined circumstances - for example if market debt rates moved outside of a pre-determined band. In this document we discuss whether we should introduce a form of debt trigger. We also commissioned a report from PwC on the form that a trigger might take and the potential advantages and disadvantages of changing our current approach. At this stage, we are not persuaded that any form of debt trigger mechanism is necessary. We have particular concerns about introducing a more mechanistic form of trigger as part of DPCR5 because of the practical difficulties in developing and consulting on such a complex and novel set of arrangements before final proposals. We would welcome views from respondents on our current position.

- **Chapter 2: Regulatory asset values (RAV).** The RAV is a financial construct used in our price control calculations to defer recovery of certain categories of costs, especially expenditure expected to provide benefits over several years. The speed of recovery is determined by the assumed regulatory depreciation rate, and a return is earned on the value of the RAV (see Chapter 1). The RAV is indexed to the RPI inflation measure. Additions to the RAV are determined by a set of rules that set which costs or proportion of costs are included in the RAV.

- **Chapter 3: Excluded services.** The price control sets allowed revenue for distribution use of system (DUoS) charges, and is based on an underlying assessment of the costs of providing this service. However, there are other

ancillary services, such as diversion works and revenue protection services which the DNO is allowed or required to provide, for which it levies other sorts of charges. These are known as excluded services, and are defined in the DNO licence. It can be difficult to isolate the costs of providing these services from those of providing price controlled use of system services, and so we have developed a methodology for allocating the overall cost base between the various services.

- **Chapter 4: Corporation tax allowances.** The DNOs are limited companies, and pay corporation tax on their profits. In our calculation of allowed revenues these profits are represented by the return to the providers of equity finance. However, there are other elements of the price control where the timing of revenues does not match the timing of costs. Tax relief for expenditure may not be on a cash basis, in particular for capital expenditure. We have developed a methodology for calculating a reasonable ex ante allowance for DNOs' corporation tax costs. We have also developed a symmetric reopener provision for material changes in tax legislation.

- **Chapter 5: Pension costs.** Pension costs, specifically the costs of providing for defined benefit pension schemes, differ from other types of costs that the DNOs face because they are inherently uncertain and can vary significantly over time. This uncertainty currently manifests itself in the form of large deficits in most DNOs' pension schemes (as with many other UK companies). We are consulting separately on our policies for recovery of these costs, but include here a summary of the modelling assumptions we have used for the purpose of the calculating revenue allowances for Initial Proposals.

- **Chapter 6: Revenue allowances and financial modelling.** This chapter brings together the effects of all our policy decisions on how much revenue the DNOs are allowed to recover. We set out the total allowed revenues, explain how we have tested that these represent sufficient revenues for the DNOs to finance their businesses, and discuss the profiling of revenues. We discuss the structure of our financial model and the work we are doing to model the within price control movements in allowed revenues that could come about through the incentive mechanisms in the price control or through external factors.

1. Cost of capital

Chapter Summary

In setting price controls, we assume that some costs are recovered over a period of time, especially expenditure expected to provide benefits over several years. This requires the DNO to obtain financing for costs not recovered immediately and so our allowed revenues need to allow a return to the providers of debt and equity finance. We describe this return as the cost of capital.

Question 1: Do you think that PwC have identified an appropriate range for setting the cost of capital?
Question 2: How should we balance our standard long-term view of the cost of capital with current indicators in the capital markets?
Question 3: Which, if any, of the alternative methods of dealing with variability in the cost of debt should we adopt?
Question 4: What are the pros and cons of the mechanistic debt trigger as suggested by PwC?

Cost of capital

1.1. The cost of capital is the return expected by investors if an efficient company is delivering an acceptable level of customer service, network performance, all of the agreed outputs and all of its statutory and licence obligations. Regulators have typically made an allowance for the efficient financing costs that a company will incur by calculating a return on the value of the capital employed in the business (the RAV) at least equal to the company's estimated cost of capital. Traditionally, the cost of capital has been presented as the weighted average cost of capital (WACC) which is calculated as the average of the expected cost of equity and the expected cost of debt, weighted for the gearing ratio.

1.2. In the December Policy Paper we signalled that the feedback we have received from most stakeholders is in favour of maintaining the existing methodology used in setting the WACC in DPCR4, and other more recent price control settlements. This is based largely on market data on long term equity and debt returns. A number of licensees have also stressed the need to take into account the current economic and financial market conditions. In the Policy Paper we confirmed that we saw no major advantage in changing our methodology and that we would maintain our post-tax approach which requires the tax allowance to be calculated separately. Our final decision will also be informed by a relative risk analysis to be performed in the period between Initial Proposals and Final Proposals. In our Initial Proposals we are using the DPCR4 Vanilla WACC of 5.55 per cent purely as a modelling assumption to allow us to illustrate allowed revenues. We also show how these revenues and the overall level of DNO prices would be affected by any change to our allowed cost of capital.

1.3. We also regulate gas electricity distribution and transmission, and electricity transmission networks through price controls. Previous recent Ofgem decisions on

the cost of capital have ranged between 4.94 per cent (Gas Distribution Price Control Review (GDPCR) 2008-13) to 5.55 per cent (DPCR4 2005-10). The table below sets out recent cost of capital allowances in other price controls:

Table 1.1 - Recent Ofgem WACC decisions

COST OF CAPITAL	DPCR3 / STPCR 2000-05	NGET 2001-06	Transco 2002-07	DPCR4 2005-10	TPCR 2007-12	GDPCR 2008-13
Debt Cost real (pre tax)	4.30%	4.45%	4.65%	4.10%	3.75%	3.55%
Equity Cost real (post tax)	6.0%	6.25%	6.25%	7.5%	7.0%	7.25%
Debt Gearing	50.0%	60.0%	62.5%	57.5%	60.0%	62.5%
Vanilla WACC	5.18%	5.17%	5.25%	5.55%	5.05%	4.94%

Current market conditions

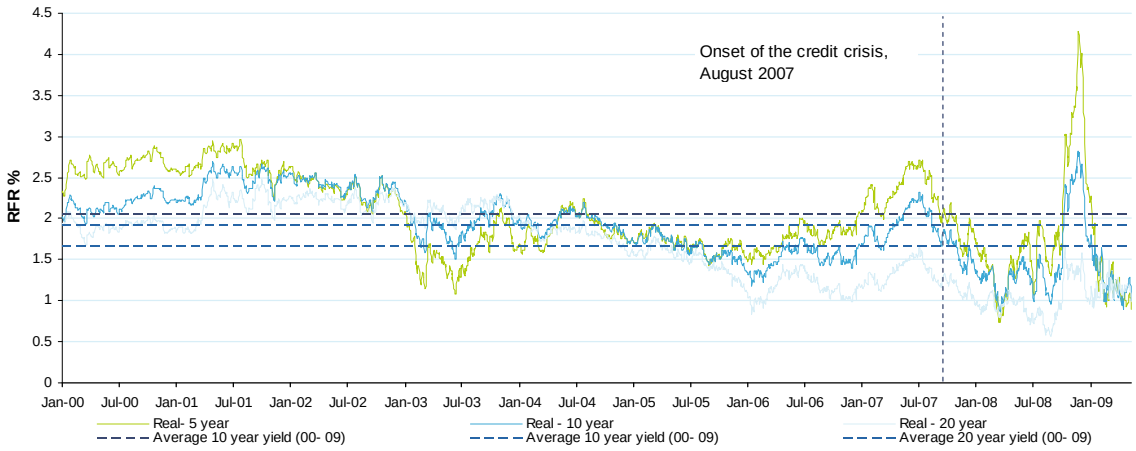
1.4. The onset of the 'credit crunch' raised concerns primarily about (i) the availability of funding and (ii) the level of spot rates both in absolute terms and the widening of the gap between A and BBB-rated bonds in the debt markets. Over recent months, the UK government and the Bank of England (BOE) have taken unprecedented measures to support lending in the UK economy and reinforce the stability of the financial system through quantitative easing. These measures have include the BOE purchasing bonds in network companies including electricity distribution networks. But, the sustainability and the pace of this relative recovery remain uncertain.

1.5. Although a large degree of uncertainty remains, in our view recent market data indicates that liquidity has returned to the capital markets, especially for low-risk borrowers such as utilities, and that spreads (although still higher than in the period preceding the credit crunch) are coming down, including for borrowers rated in the BBB range. The current climate is also characterised by low and falling yields in 'risk free' assets such as Index-linked gilts (ILGs) and a fall in equity prices since the onset of the 'credit crunch'.

1.6. Two trends can be observed in the yields on ILGs since the onset of the credit crunch. First, yields have been much more volatile. In our view this strengthens the argument for placing more emphasis on long-term averages. Secondly, the current spot rates, across 5-, 10- and 20-year maturities are significantly below their long

term averages of 2.1 per cent (5 years), 1.9 per cent (10 years) and 1.7 per cent (20 years).

Figure 1.2 - Evolution of ILGs yields



1.7. Despite the difficult conditions, utility companies have continued to access credit (both through loans and bond issuances). But these have tended to be shorter duration and at a higher cost than prior to the credit crunch. In the secondary market, bond yields for utility companies have also increased. However, on the whole it appears that the spreads faced by utilities have been impacted less by the broader market turmoil. Commentators suggest this is because of the sector's defensive qualities and resilience to the effects of the fall in economic output relative to other companies and sectors. This is also reflected in utility share price relative to the whole market. At April 2009, the FTSE-Utilities Index had lost 18 per cent compared to 33 per cent for the FTSE-100 Index since August 2007.

Figure 1.3 - Yields - Cross sector comparison, A-rated bonds

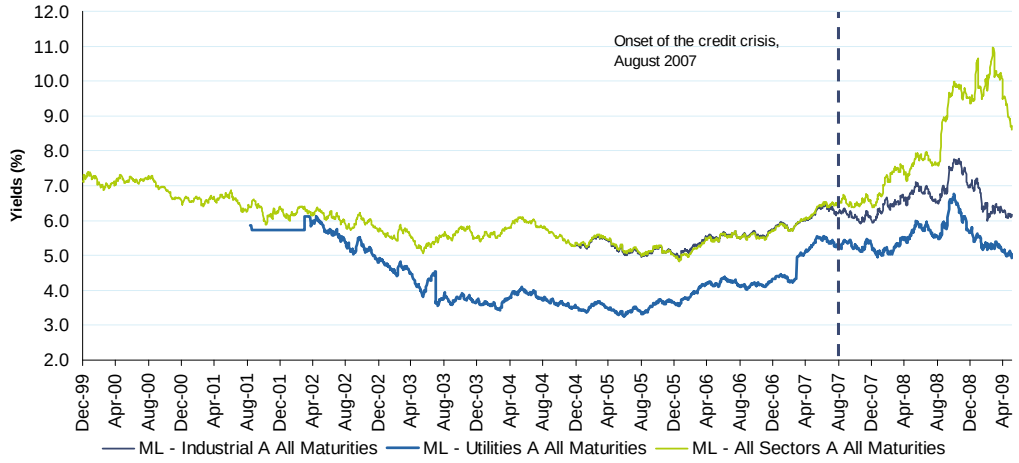


Figure 1.4 - Evolution of the FTSE-100 and FTSE-Utilities indices

Methodology and indicative range

1.8. Our current view is that we should maintain our approach of putting more weight on long term evidence, especially since we are setting the WACC for the period 2010-2015 rather than the next few months. However, we will balance that with consideration of the need to finance substantial incremental investment and the possibility that, in the near term at least, new finance may only be available at rates higher than those suggested by long-term historical evidence.

1.9. If this is the case, one way of helping the companies to manage this risk without exposing customers to excessive costs or risks could be to introduce a trigger or reopener for the cost of debt. The potential forms that a debt trigger might take and the advantages and disadvantages of different forms relative to our existing approach are discussed in paragraphs 1.22 to 1.26.

1.10. To assist and inform our judgement of the appropriate cost of capital for DPCR5, we commissioned external advice from PwC[1]. The following section describes the methodology used by PwC and the WACC range they produce.

Cost of equity

1.11. The debate focuses primarily between the traditionally used Capital Asset Pricing Model (CAPM) approach and the Dividend Growth Model (DGM). The latter is forward looking and assumes that the cost of equity is the sum of expected dividends. CAPM assumes that the cost of equity is the sum of the return available on risk-free instruments plus a premium for the risk involved in equity investment. The latter is equal to the general equity risk premium adjusted to reflect the relative riskiness of an investment compared to the market as a whole.

$$Ke = RFR + \beta * [ERP]$$

Where:

Ke is the cost of equity

RFR is the risk-free rate

β is the equity beta

ERP is the equity risk premium (Rm – Rf), where Rm is the equity market return

1.12. In the UK the DGM has not typically been used by regulators as the primary method for estimating the cost of equity (although the DGM can be used to calculate the equity risk premium within the CAPM framework - see below) as it requires accurate forecasts of expectations of growth and it produces highly volatile estimates of the cost of equity because it is affected by share price movements. PwC advocate the use of CAPM as the principal methodology for calculating the cost of equity.

[1] The complete PwC report is available as an associated document to this publication.

Risk free rate (RFR)

1.13. Traditionally, the return on Index-linked gilts (ILGs) has been used to measure the RFR. Some consultants in the sector (most notably NERA[2]) have argued for the use of swap rates instead of ILGs for estimating the RFR. It is argued that ILG spreads are low as there is a high (and inelastic) demand for these instruments from UK pension funds. In our view, the use of swap rates is fraught with difficulties not least because it relies on accurate estimates of expected inflation. The Competition Commission considered the issue in the Stansted Airport Price Control Review and decided against the use of swaps because of data concerns. PwC propose retaining the use of ILGs as the main tool for estimating the RFR and use swap rates and nominal gilts as a cross check. They also propose that we retain our long term approach and put greater weight on five to ten year averages rather than current spot rates.

Equity Risk Premium (ERP)

1.14. The ERP measures the additional return investors expect to compensate for the degree of risk they are assuming. The current debate for estimating the ERP focuses primarily between the traditionally used ex-post (historic) approach and ex ante (forward looking) methods such as the DGM. PwC's approach is to consider estimates using primarily ex post evidence (based on very long-term datasets) as well as recent regulatory decisions and using ex ante evidence as an additional sense check.

Beta estimates[3]

1.15. In estimating betas, PwC have primarily used a UK comparator sample set, in order to avoid any distortions caused by differences in regulatory risk across different countries, using an international comparator analysis as a cross check. They have given more weight to five year monthly betas as they tend to be more stable and reflect a long-term view of the DNOs' asset betas. They have also used adjusted asset betas and a debt beta range of 0 to 0.1, the latter in order to reflect the recent Competition Commission approach, thus producing a relatively wide range of beta estimates.

[2] NERA have prepared a report on behalf of the DNOs. It is available as an associated document to this publication.
[3] For a detailed discussion on the relationship between equity, asset and debt betas please see Appendix II of the PwC report.

Overall cost of equity

1.16. NERA has argued that the credit crunch has also led to a long-term shift in the cost of equity. We are not persuaded of this because established corporate finance theory says that the cost of equity should be relatively stable over time. As the cost of equity is not directly observable and the data on the credit crunch is very short term it is difficult to find good evidence to support NERA's arguments. But the lower end of the cost of equity range presented by PwC would entail a figure much lower than any recent, comparable regulatory settlements.

Debt spreads

1.17. In their analysis PwC look at three sources of information: general market data, utility specific secondary market data and, as a cross check, utility specific primary (i.e. bond launch spreads) market evidence. The focus is again on long term rather than spot rates and they recommend using the ten year average premia.

Gearing

1.18. We have already signalled in the Policy Paper that we do not see any reasons or evidence to support a significant departure in the gearing assumption compared to the other recent Ofgem decisions. The notional gearing level used in the calculation of the WACC was 57.5 per cent, 60 per cent and 62.5 per cent in DPCR4, TPCR and GDPCR respectively. Discussions with the rating agencies support this view. We still consider that a notional gearing level of 55 to 65 per cent remains consistent with a rating that is comfortably within investment grade. PwC also use this assumption.

1.19. Following this methodology, PwC's proposed WACC range is:

Table 1.5 - PwC's proposed WACC range

Range	RFR	Betas	ERP	Cost of equity	Debt Spreads	Cost of debt	Gearing	Vanilla WACC
Max	2.5%	1.1	5.5%	8.5%	1.5%	4.0%	55%	5.6%
Min	1.9%	0.5	4.0%	4.0%	1.2%	3.1%	65%	3.5%

1.20. All of the recent Ofgem decisions on cost of capital, which have all been accepted by the relevant companies, lie within this range, although typically at the higher rather than lower end.

1.21. We would welcome views on PwC's methodology and proposed range. We are particularly interested in feedback supported by evidence on whether they have

identified an appropriate upper level. As well as tracking developments in capital markets over the next few months and considering the responses to this consultation we will be seeking to get an appropriate balance between our decision on WACC and the risk and rewards available to DNO shareholders through all of the elements of the price control. The decision we make on whether it is appropriate to introduce a mechanism to handle uncertainty around the cost of debt will be one of several factors that influence our final decision on WACC. This is discussed further below.

Cost of debt trigger / reopener

1.22. Traditionally we set the cost of capital on an ex ante basis and have left the DNOs to manage any risks that arise from fluctuations in the capital markets. We still consider this to be the most appropriate approach within the RPI-X regulatory framework. In the Policy Paper we signalled, however, that as a result of the turbulence in the capital markets and representations from some respondents in this (and previous) price control reviews we would consider implementing a cost of capital trigger and/or reopener, although not a mechanism that sought to index the allowed cost of debt fully to a market benchmark. Since the Policy Paper we have consulted extensively with PwC, as well as stakeholders and their consultants on this issue and in particular on how such a mechanism would operate in practice. We are not minded to introduce any new mechanism into the price control to manage cost of debt fluctuations. This is because we consider that long-term debt is available at rates that, if inflation returns to the levels typically seen over the last ten years, are consistent with recent price control decisions. But, we would welcome views on our position and the options outlined from respondents. We may also revisit this position if market conditions deteriorate rather than continue to improve further.

1.23. To help respondents give their views on this issue, we have set out below - based on the work of our consultants PwC - the options for dealing with this issue:

1. continue with the current framework, perhaps reviewing the disapplication procedure, which provides an opportunity for the Authority to reopen a price control at a licensee's request,

2. introduce a mechanistic cost of debt trigger,

3. introduce a reopener, which could take the form of a specific reopener on cost of debt or a 'substantial effect' clause, of the type Ofwat have, which is not for any specific issue, but which allows the regulator to take the company's overall position into account, or

4. introduce a mechanism whereby the cost of debt is adjusted within the price review period (say every 2.5 years).

1.24. PwC considered these options using seven criteria:

- Consumer benefit. Reflecting our primary duty to protect the interests of present and future consumers, each of the options is assessed in terms of its impact on consumers. We have assessed the impact of each of the proposed mechanisms on the expected level of electricity distribution prices and their variability.

- Incentivisation. It is important to consider how each of the options impact the regulated companies' incentives to make efficient financing decisions and, more generally, to operate efficiently.

- Complexity. As far as possible, the regulatory framework should avoid excessive complexity in favour of clear and simple rules.

- Transparency. For any form of regulation to be effective, it should be transparent to all the affected parties. In particular, the DNOs should have a good understanding of how and under what circumstances they can expect to be affected by Ofgem's decisions, and be clear on the size and timing of any future adjustments to allowances.

- Targeted approach. Our key underlying concern is to ensure that credit market conditions over DPCR5 do not compromise the ability of a prudent and efficient DNO to undertake its planned investment programme and to refinance any maturing debt. Each option is considered in terms of whether it allows a prudently operated notionally geared DNO to finance its obligations under a range of credit market conditions.

- Proportionality. Any mechanism adopted should ensure that interventions occur only when they are necessary and that interventions are proportionate to the magnitude of the issue.

- Consistency. The approach should be consistent with the broader RPI-X regulatory framework within which the DNOs operate and its application to date.

1.25. PwC's recommendations are summarised below:

Table 1.6 - PwC assessment of cost of debt trigger options

Option	Consumer benefit	Incentivisation	Complexity	Transpar-ency	Targeted approach	Proportion-ality	Consistency
	Does the mechanism benefit the consumer (risk v. prices)?	Does the mechanism preserve the DNOs' incentives?	Simple and user friendly approach?	Clear when/how the regulator is likely to intervene?	Does the mechanism apply when an intervention is needed?	Is intervention proportionate to the issue?	Does the mechanism align with the broader reg. framework and its previous application?
Option 1: Continue with the existing approach	✓✓	✓✓	✓✓	××	~	~	✓✓
Option 1a: Option 1 + disapplication clause review	✓✓	✓✓	✓✓	✓	✓✓	✓	✓✓
Option 1b: Introduce Cost of debt headroom	××	✓	✓✓	××	~	×	××
Option 2: Cost of debt trigger mechanism	✓	~	××	✓✓	✓	✓	~
Option 3: Substantial effect clause	✓✓	✓✓	✓	✓	✓✓	✓✓	✓✓
Option 4: Option 1 + Time based reopener	PwC did not consider this option in detail						

1.26. PwC recommend options 1a and 3. Our current position is option 1 but given the high degree of uncertainty in the capital markets, we may have to revisit this position as we move to Final Proposals. We are particularly concerned about the practicality of designing, consulting on and implementing Option 2 as part of the current review. This would require extensive further work to develop a suitable mechanism as a suitable index to base the trigger on does not, in our view, currently exist. Our current view is that this issue may be better considered and consulted upon as part of the RPI-X@20 project. Again, we would welcome views.

1.27. We will, of course, consider carefully any responses on this issue before coming to a final view.

1.28. PwC have designed a cost of debt trigger and we would like to invite the views of stakeholders on the mechanics of that trigger. The trigger is presented in PwC's report entitled 'Options for Dealing with cost of debt fluctuations' and can be found as an associated document. We would welcome stakeholders' views on whether this mechanism represents a workable automatic protection mechanism, even in cases

where it is not the stakeholder's favoured approach. All responses will also be fed into our RPI-X@20 project, which is considering financing issues as part of its review of the regulatory framework.

2. Regulatory asset values (RAV)

Chapter Summary

The RAV is a financial construct used in our price control calculations to defer recovery of certain categories of costs, especially expenditure expected to provide benefits over several years. The speed of recovery is determined by the regulatory depreciation rate, and a return is earned on the value of the RAV (see Chapter 1). The RAV is indexed to the RPI inflation measure. Additions to the RAV are made according to a set of rules that determine which costs or proportion of costs are included.

This chapter sets out an update to our policy for the timing of the recovery of expenditure and our overall approach to computing RAV additions for DPCR5. It also sets out our position to finalising the closing RAV for DPCR4 at 31 March 2010.

Question 1: Do you agree with the draft rules for computing RAV additions and will they reduce or eliminate boundary issues at DPCR5. If not how should they be amended?
Question 2: In what circumstances would you consider it appropriate to have DNO-specific RAV additions percentages?

Background

2.1. This chapter provides an update on our methodology for determining the timing of cost recovery for the DNOs and our overall approach to computing RAV additions for DPCR5. This methodology is based on the concepts of fast and slow money explained in the May Methodology and Initial Results paper. To arrive at draft revenue allowances for DPCR5 we need to agree the opening RAV per company. This is not a straight forward exercise as we do not have data for year five of DPCR4. We also need to estimate the closing RAV per company according to the Ofgem view of expenditure over DPCR5 and the appropriate rules for whether expenditure is funded in period or through additions to RAV. We also set out our position on finalising closing RAV for DPCR4 at 31 March 2010 and the resulting values of RAV rolled forward into DPCR5.

Approach to the methodology

2.2. In developing the new methodology for setting RAV additions our objectives have been to:

- ensure that the regulatory arrangements do not distort DNO decision making. We are keen to avoid any skewed incentive on the companies to invest in network assets, rather than focussing on the expected lowest lifetime cost particularly where there is uncertainty over future levels of demand for network capacity. This may entail incurring additional operating costs, including solutions such as

demand side management to keep options open by deferring making investments in long lived assets,

- address the boundary issues for cost reporting,
- remove mismatch in the treatment of total connection costs and contributions,
- reduce the perverse incentive to out-source rather than in-source because of the different RAV treatment of direct and indirect costs,
- review the possible disincentive on DNOs to provide excluded services because of arrangements that currently adjust the costs allocated to RAV if DNOs carry out more activity than they originally forecast (see Chapter 3 for details),
- resolve the treatment of captive insurance costs and margins, and
- specify the treatment and data requirements relating to margins when a related party ceases to be controlled by the same ultimate controlling party/(ies) as the licensee.

2.3. In Appendix 2 we set out the draft methodology rules for computing RAV additions and allowed costs of an efficient and economic distribution business. These will be finalised at Final Proposals.

Update on policy for the timing of recovery of expenditure

2.4. In the May Paper, we set out two options for computing RAV additions. The first is to apply a fixed percentage to total costs (totex) of the distribution business using the four building blocks. The second to exclude business support costs. The building blocks are (i) Network Investment, (ii) Direct Opex (including non-op capex) costs, (iii) Engineering Indirect costs and (iv) Business Support costs. We are using the second option for Initial Proposals as this received broad support from respondents. This approach resolves the majority of boundary issues and allows the retention of a strong incentive rate for business support costs to be managed efficiently.

2.5. As set out in the chapter on *Equalising incentives and the information quality incentive* in Technical Document 1 we intend to maintain a similar level of capitalisation of costs as at DPCR4. This means that the RAV additions percentage (or slow cost recovery) applying to network costs has been set to ensure that a similar proportion of costs are expected to be capitalised during DPCR5 as if we applied the RAV additions rules used in DPCR4. The network costs that are not capitalised will be funded in the year of expenditure, i.e. fast cost recovery. Business support costs will also be funded entirely in the year of expenditure. We have reviewed the indicative percentage for RAV additions. To maintain the same rate of recovery of expenditure as under the DPCR4 rules we calculate that around 85 per cent of network-related costs would need to be capitalised. This is slightly above the percentage indicated in our May Document as the ratio of capex to opex in DPCR5 is higher in DPCR5 than in DPCR4, on which our May percentage was based.

2.6. Respondents have accepted our overall approach in the May consultation. Some suggested that they would like a higher percentage of costs to be capitalised. Another proposed a separate accelerated RAV pot for truing up pension deficit funding costs amortised over five years, in recognition of the different timing of funding cashflows: RAV over 20 year and pension deficits over a period of between three and ten years. We do not however, see the need to change our approach to pensions true up set out in DPCR4.

2.7. We have also explored with DNOs the option of setting DNO specific RAV addition percentages. The advantage would be to tailor the level of capitalisation to each DNO's circumstances, taking account of factors such as the scale of investment relative to ongoing costs and to existing RAV. We have not adopted this option, but may explore this further and keep under review for the Final Proposals.

Regulatory depreciation and asset lives

2.8. Our choice of asset lives - i.e. the rate of depreciation of the RAV impacts the speed at which the DNOs can recover the costs added to the RAV. The shorter the asset lives, the faster this recovery occurs and the higher allowed revenues are in the short term due to the higher depreciation allowance. Scottish DNOs are facing a large reduction in their depreciation allowance as their vesting assets[4] become fully depreciated (the so-called depreciation "cliff-face") at the end of 2009-10. The English & Welsh DNOs faced this cliff-face at previous reviews. This was resolved by accelerating asset lives from those assumed at vesting (which varied from 11 to 15 years for English and Welsh DNOs and 20 years for Scottish DNOs) to 20 years with a catch-up for assets already added to the RAV since vesting. The catch up is smoothed over 15 years in equal instalments. We are extending the same treatment to the Scottish DNOs and continuing with this policy in DPCR5.

2.9. Some respondents suggested that changing the regulatory asset lives increases the level of regulatory risk and that were we to do this they should be compensated by a higher cost of capital. We do not agree with them and consider that as in DPCR4 decreasing asset lives is a potential option to address financeability issues should they arise. For initial proposals, we have retained the current regulatory treatment.

2.10. These issues are also being considered as part of the RPI-X@20 review.

[4] Vesting assets comprise all assets held by a business at Vesting (i.e. privatisation), with the initial value based on flotation values.

Other RAV policies - Pensions

2.11. We are consulting separately on the options for dealing with pension costs. For modelling purposes, we have assumed in initial proposals that pension costs will follow the treatment of the underlying employment costs in each of the fast and slow pots. Thus to the extent that they are associated with business support costs, they will be recovered by DNOs as 100% fast money, and to the extent they are associated with networks costs they will be recovered 85% through the RAV and the remainder as fast money. On the other hand, deficits arising from past decisions and fluctuations in market conditions, and are not connected with future investment activity. For these initial proposals our assumption is that pension deficit repair costs will be funded on a pay-as-you-go basis, albeit with a profile set by Ofgem. We discuss this further in chapter 6.

Related party margins on changes of group structures

DPCR4 position

2.12. Following changes in DNO group structures in DPCR4, the application of the rules on the treatment of the margins of related parties, which cease to be related in a price control period, have been dealt with on an ad hoc basis. We think we should clarify our treatment of these costs.

Future position

2.13. We think that from the moment an affiliate ceases to be a related party its margins will be allowable subject to one condition and one exception. The condition is that there is an unambiguous demonstration that its charges to the distribution business (in the original or amended contract) remain competitive and are in line with prevailing market rates or until the contract is re-tendered and there is more than one bidder. DNOs will need to demonstrate this condition is met. The exception is where a principal related party resource provider ceases to be a related party for any reason.

2.14. On a principal related party resource provider[5] ceasing to be a related party during a price control period, for example on the restructuring of a group, it shall continue to be treated as a related party until the end of that price control and the

[5] A principal related party resource provider is one that has a contract to operate or manage a substantial part of a licensee's day-to-day operations, which was entered into before or as part of the arrangements for a change in ultimate controller, or controllers where there is more than one ultimate controller.

margins charged will be disallowed. At the next price control period the margins will be allowed subject to the same condition set out in the previous paragraph.

Connections

2.15. Customer contributions will be treated in the same way for RAV purposes as the gross costs of providing the connections. Sole use connections, (fully funded by customer contributions) will no longer be taken into account for setting allowed demand revenues or for RAV purposes. We will still need to monitor closely the allocation of indirect costs between this activity and other activities still covered by price control revenues to ensure that those related to sole use connections are excluded.

Regulatory asset value to 31 March 2010

2.16. At DPCR4, we established annual cost reporting procedures and we have published an annual cost review setting out the indicative RAV. The last report was for the 2007-08 regulatory financial year. This process, which introduced a consistent treatment of costs, did not rely on DNOs' own accounting policies as was the case in previous controls in computing RAV. It still had issues of interpretation and throughout the period we have sought to address boundary issues between activities, e.g. faults and asset replacement, and direct and indirect labour. The process has been more transparent and enabled us to resolve issues throughout the period.

2.17. The RAV values published below in table 2.1 are those we are using for the opening value of the RAV in arriving at DPCR5 revenue allowances. They have been prepared in accordance with Appendix 1 to the DPCR4 Final Proposals and the guidance in the annual Price Control Cost Reporting Rules - Instructions and Guidance prepared and amended in accordance with standard licence conditions 48 and 49.5 respectively. They are based on actual costs to 31 March 2008 and DNOs' forecasts for the final two years to 31 March 2010. These will be updated when annual cost returns are available for the year to 31 March 2009.

Table 2.1 - Closing RAV values at 31 March 2010

£m 2007-08	Opening RAV at 1 April 2005	Additions	Depreciation	Closing RAV 31 March 2010	Under-grounding adjustment	Opening RAV 1 April 2010
CN West	1,124.5	716.4	(485.0)	1,355.9	2.9	1,358.8
CN East	1,111.3	681.1	(485.2)	1,307.2	0.9	1,308.1
ENW	1,078.9	607.9	(462.2)	1,224.6	2.8	1,227.3
CE NEDL	695.0	433.4	(300.4)	828.0	2.7	830.7
CE YEDL	941.7	517.3	(398.4)	1,060.6	1.0	1,061.6
WPD S Wales	676.2	292.3	(297.2)	671.2	0.0	671.2
WPD S West	831.5	431.1	(348.4)	914.2	0.0	914.2
EDFE LPN	1,037.3	622.2	(444.2)	1,215.3	0.0	1,215.3
EDFE SPN	719.6	596.6	(318.3)	997.9	4.0	1,001.8
EDFE EPN	1,280.1	933.6	(539.2)	1,674.4	1.0	1,675.4
SP Distribution	1,474.0	516.2	(669.1)	1,321.2	0.5	1,321.7
SP Manweb	869.8	623.8	(373.2)	1,120.4	3.3	1,123.7
SSE Hydro	856.4	297.9	(310.6)	843.7	3.9	847.6
SSE Southern	1,574.4	750.2	(654.4)	1,670.2	3.7	1,673.9
Total	**14,270.5**	**8,020.0**	**(6,085.8)**	**16,204.7**	**26.7**	**16,231.4**

2.18. The RAV numbers shown above in table 2.1 differ from the forecast made in the DPCR4 Final Proposals. There are a number of factors that have caused this as shown in table 2.2 below.

Table 2.2 - Movements in forecast closing RAV in DPCR4

	Final Proposals DPCR4 (2002/03 prices)					Adjustments to DPCR4 forecast (2007/08 prices):				
	2009/10 Forecast Closing balance	Adjustments for 2004/05 actuals	Restated closing balance	Inflation to 2007/08 prices	Closing balance (2007/08 prices)	RAV additions	Regulatory Depreciation	ESQCR adjustment	Undergrouding & AONB adjustment	2009/10 RAV closing balance £m
CN West	1,151.6	(7.8)	1,143.8	200.2	1,344.0	5.5	0.4	5.9	2.9	1,358.8
CN East	1,115.6	(2.3)	1,113.3	194.9	1,308.2	(10.8)	5.6	4.2	0.9	1,308.1
ENW	1,080.9	(1.9)	1,079.0	188.9	1,267.8	(62.5)	6.0	13.2	2.8	1,227.3
CE NEDL	699.9	(5.2)	694.7	121.6	816.3	4.4	2.8	4.5	2.7	830.7
CE YEDL	906.1	(3.3)	902.8	158.0	1,060.9	(11.5)	3.5	7.8	1.0	1,061.6
WPD S Wales	569.1	1.8	570.9	99.9	670.8	(1.2)	0.3	1.3	0.0	671.2
WPD S West	762.1	12.0	774.1	135.5	909.6	1.1	(3.0)	6.5	0.0	914.2
EDFE LPN	1,075.4	(26.5)	1,048.9	183.6	1,232.5	(32.7)	15.5	0.0	0.0	1,215.3
EDFE SPN	936.3	(29.1)	907.2	158.8	1,066.0	(100.3)	25.3	6.9	4.0	1,001.9
EDFE EPN	1,456.3	(49.1)	1,407.2	246.3	1,653.5	(21.5)	31.4	11.0	1.0	1,675.4
SP Dist	1,092.8	20.9	1,113.7	195.0	1,308.7	(9.7)	(1.1)	23.3	0.5	1,321.7
SP Manweb	911.2	4.7	915.9	160.3	1,076.2	(2.5)	(3.6)	50.2	3.3	1,123.7
SSE Hydro	708.5	0.9	709.4	124.2	833.5	2.5	2.6	5.1	3.9	847.6
SSE Southern	1,483.5	(10.2)	1,473.3	257.9	1,731.2	(86.9)	22.2	3.7	3.7	1,673.9
Total	13,949.3	(95.2)	13,854.1	2,425.2	16,279.3	(326.2)	107.8	143.8	26.7	16,231.4

2.19. The undergrounding adjustment is for costs logged up in DPCR4 in accordance with the DPCR4 Final Proposals section 4.60. These only include the direct capital expenditure and exclude related indirect costs.

RAV calculation 2008-09 and 2009-10

2.20. Our Initial Proposals have used estimates of 2008-09 and 2009-10 expenditure provided by the companies in the spring of 2009, on the understanding that these were best estimates at the time. We received updated estimates from the DNOs in June but there are various problems with this data that prevent us from using it in the opening RAV for our draft revenue allowances. We have agreed with DNOs to resolve this matter following initial proposals and publish this in the September update.

2.21. In the event that actual 2009-10 RAV additions turn out to be materially different to the estimate used in our Final Proposals, we would not expect to alter revenue in the period 2010-15. If the difference is not due to genuine efficiencies that could not reasonably have been foreseen at the time the forecast was provided, Ofgem will claw back the benefits of any under-spend in 2009-10 relative to the estimate used in these proposals at the next review and alter the revenue in the 2015-20 price control.

Forecast RAV movements in DPCR5

The forecast movements in RAV over DPCR5, based on our cost assessment work (see the Initial Proposals cost assessment document for details), are set out in

chapter 6 and have been computed in accordance with the methodology statement in Appendix 2.

3. Excluded Services

Chapter Summary

The price control sets allowed revenue for distribution use of system charges, and is based on an underlying assessment of the costs of providing use of system services. However, there are other ancillary services that DNOs are allowed or required to provide and for which they make separate charges. The revenues associated with these services falls outside the scope of the charge restriction licence conditions. These are known as excluded services and are defined in the DNO licence. It can be difficult to isolate the costs of providing these services from those of providing use of system services and so we have developed a methodology for allocating the overall cost base between the various services.

Question 1: Do you agree with our proposal to bring the distribution of units to new EHV premises, provision of charging statements and reactive energy transportation within the scope of the main charge restriction conditions (see paras 3.9 to 3.19 below)?
Question 2: Do you agree that revenue protection services should be exempt from a RAV adjustment where reported revenues exceed forecast revenues and that the definition should make clear that the service only includes work commissioned by a third party? (see paras 3.20 to 3.22 below)
Question 3: Do you agree with the proposed RAV adjustments for top up & standby, other system charges and metering excluded services where reported revenues (costs in the case of metering) exceed forecasts? (see paras 3.23 to 3.32 below)
Question 4: Do you agree with our proposals with regard to diversion works in DPCR5? (see paras 3.36 to 3.37 below)
Question 5: Do you agree with our proposals regarding metering excluded services? (see paras 3.29 to 3.32 below)

Excluded Services in DPCR5

3.1. In our May 2009 paper we suggested several approaches to the treatment of excluded services for DPCR5:

a. Retain the DPCR4 classifications and price control treatment:

- Forecast revenues for 'relevant' excluded services are deducted from allowed revenues as this assumes they are a reasonable proxy for the operational costs involved
- Costs and revenues relating to 'non relevant' excluded services are not factored into main price control calculations
- Revenue from charges for excluded services are not counted towards price controlled allowed demand revenue

- Revenue in excess of original forecasts for relevant excluded services are deducted from out-turn costs, with a consequential deduction from RAV (23.5 per cent in DPCR4, 85 per cent in DPCR5)

b. Apply a similar approach but using all-DNO averages as forecast revenues for relevant excluded services to encourage higher levels of activity making greater, and possibly more efficient use of distribution business assets,

c. Apply a similar approach but reduce the degree of RAV 'claw-back' resulting from excess revenue from relevant excluded services to reduce any disincentive to carry out activities, or

d. Apply a form of 'cost plus' price control to excluded services recognising a return/margin in charge levels subject to a comprehensive cost reporting regime.

3.2. The claw-back applied to excess revenue from relevant excluded services in DPCR4 was intended to address the possibility of resources being funded twice - both through price controlled allowed revenue and through excluded services charges. The overall impact on the DNO is less than the 23.5 (or 85) per cent deduction referred to above once the RAV rolling incentive is taken into account (see example at paragraph 3.32 below).

Turnover levels for excluded services so far in DPCR4

3.3. The table below shows average annual revenues (all DNOs) during the first three years of DPCR4 with relevant excluded services marked (R).

Table 3.1 - Average of total excluded services revenue figures (DPCR4)

Excluded service	£m
ES1: Use of system - post 1 April 2005 EHV sites (R)	1.6
ES2: New and modified connections	556.9
ES3: Revenue protection services (R)	4.5
ES4: Provision of charging statements (R)	0.0
ES5: Diversion works (statutory requirement)	31.0
ES6: Diversion works (no statutory requirement)	60.2
ES7: Top up and standby/enhanced security (R)	31.0
ES8: Reactive energy transportation for premises with power factor < 0.95 (R)	23.8
ES9: Other system charges (not DUoS/metering or other ES) (R)	12.8
ES10: Metering except Legacy MAP (2007/08 figure)	69.7

3.4. The DPCR4 treatment of connection costs and revenues varied. 100 per cent of direct activity costs (net of all contributions) fed into the RAV/ Indirect costs were treated in the same way as other indirect activity costs with an effective 53 per cent feeding into RAV).

3.5. The full definitions for the current categories of excluded services can be found at Appendix 1 to special condition A2 of the electricity distribution licence which is available via the electronic public register on Ofgem's website.

Responses to the May 2009 paper

3.6. Several DNOs responded to the section in the May paper on excluded services, both in written submissions and at bilateral meetings on financial issues. The possibility of a cost plus approach received little support; respondents felt that a requirement to record and report detailed costs information for the full range of excluded services would be disproportionately onerous.

3.7. Concerns were expressed about the use of all-DNO averages to set expected revenue levels for excluded services because of varying network/business characteristics and legacy factors. DNOs expressing this opinion considered that a continuation of the present arrangements would be more acceptable.

3.8. Some respondents considered that the treatment for excluded services going forward should be considered on a category by category basis, with a presumption that all distribution activities should be included within the main price control except where there is a good reason for them to be dealt with separately. One respondent also suggested that there should be scope for additional, emerging activities to be included within excluded services as DNOs respond to customer requirements.

Ofgem's view having considered feedback received

Proposal to bring some activities presently classified as excluded services within the scope of the charge restriction conditions

3.9. We consider that three of the existing categories of excluded service should be brought within the scope of the price control charge restrictions for DPCR5. This is based on experience from DPCR4 and developments for DPCR5. We intend to modify relevant licence conditions so that they would no longer be scheduled as excluded services.

Distribution of units to EHV premises connected (or materially altered) after 1 April 2005

3.10. Distribution of units to existing EHV premises were brought into the scope of the price control for DPCR4, but the service of distributing units to premises

connected (or materially altered) after the start of DPCR4 was excluded. The exclusion was mainly to address concerns that the growth driver associated with base demand revenue might not adequately cater for the impact of large new industrial premises whose use of system tariffs are generally set on a capacity basis.

3.11. However, the level of reported revenues for this service in DPCR4 and the level of forecast revenues for DPCR5 are relatively low and DNOs have no forecast costs in this category. This suggests that the infrastructure requirements for these sites have largely been catered for in general network reinforcement or through site specific connection charging agreements with the customers concerned. In addition, our minded to position is that there will not be a growth driver for base revenue in DPCR5.

3.12. In light of these factors, our proposal is that all distribution of units to EHV premises should be included within the price control for DPCR5 with revenues counting towards price controlled allowed demand revenue. In the case of an exceptionally large/unexpected development it might be open to the DNO concerned to make a re-opener application under the provisions outlined in chapter 5 of the accompanying Initial Proposals document 'Allowed revenue - Cost Assessment'

Provision of charging statements

3.13. This service consists of the provision of charging statements by DNOs required under:

- Standard licence condition 13 (Charging Methodologies for Use of System and connection)
- Standard licence condition 14 (Charges for Use of System and connection)
- Standard licence condition 18 (Provision of and charges for Metering Point Administration Services)
- Standard licence condition 21 (The Distribution Code)
- Standard licence condition 36 (Charges for the provision of Legacy Metering Equipment and Data Services)

3.14. In each case the DNO is allowed to make a charge for sending the document to a requestor not exceeding the amount specified in directions issued by the Authority based on its estimate of the licensee's reasonable costs of providing it. However, the costs and revenues reported in respect of this service, and forecast for the DPCR5 period are relatively immaterial.

3.15. We propose that for DPCR5 this service should not be scheduled as an excluded service since it could more appropriately be considered as part of the finance and regulation activity of the distribution business. We propose that the DNO should still be able to make a cost reflective charge for the provision of the documents where appropriate, with revenue being reported as a cost reduction item in regulatory cost returns.

Reactive energy transportation

3.16. Reactive energy is the 'wattless' element of apparent power and 'consumption' is highest in industrial premises with poor power factors. Reactive energy 'consumption' imposes additional generating requirements which add to network costs and increase carbon emissions.

3.17. In DPCR4 the transportation of reactive energy[6] was scheduled as an excluded service to encourage DNOs to charge for it under separate tariffs which would in turn provide industrial consumers with the information necessary to consider an investment in power factor correction equipment at their own facilities. In responses to the May paper, DNOs indicated that the costs associated with reactive power requirements mainly relate to longer term load related network reinforcement.

3.18. Under the prospective common charging methodology DNOs will be obliged to apply reactive energy tariffs when appropriate. In light of that, we do not consider it necessary to schedule reactive energy transportation as an excluded service for DPCR5. We consider it is more appropriate to treat it in the same way as other use of system tariffs and include it in the main price control calculations. We will keep under review whether any incentive mechanism might be appropriate to encourage reductions in reactive energy transportation requirements.

3.19. If these three categories of service are not treated as excluded services for DPCR5 it follows that we would not propose to deduct any forecast revenues relating to these services from price controlled allowed expenditure or allowed demand revenue.

Proposals for 'relevant' excluded services in DPCR5

Revenue protection services

3.20. DNOs have basic reporting duties in relation to theft, damage and meter interference under current licence standard condition 27 and the DCUSA. We consider that DNOs are well placed to provide additional revenue protection services to suppliers where they require this.

3.21. DNOs are not obliged to provide enhanced revenue protection services and suppliers do have some choice in obtaining services - for example they could set up an in-house resource or use an alternative third party provider. The appropriate price for the service is likely to be the one that is mutually acceptable to both parties

[6] to premises with a power factor <0.95

and in those circumstances we would only expect to stipulate that charges should be set be set at a level which will allow the licensee to recover no more than its reasonable costs and a reasonable rate of return in providing the services.

3.22. We propose to deduct DNOs' forecast revenues for this service from DPCR5 price control allowed expenditure and hence from allowed revenue. On the basis that this is a facility which we would wish to encourage and, given the relatively small amounts of revenue involved, we would not propose to apply any RAV adjustment where increased activity by a DNO means that its revenues are higher than those predicted in its FBPQ. We would, however, propose to make clear in the definition for the service that it only includes revenue protection services commissioned by a third party (which could be a related party) and not any activities conducted by the DNO on its own initiative to reduce non-technical system losses, this activity coming under the main price control.

Top up & standby/enhanced security

3.23. This is the service to customers who require extra capacity at certain times or a level of security higher than that required in relevant engineering recommendations. Although it could be considered a 'premium' service it can generally only be obtained from the DNO.

3.24. Although charging for these services is likely to be addressed in the prospective common charging methodology for DNOs we consider it would be appropriate for them to remain excluded services in DPCR5. Since DNOs would find it difficult to identify separately the costs involved in providing this service we propose to deduct DNOs' forecast revenues for this service (as a proxy for costs) from DPCR5 price control allowed expenditure and hence from allowed revenue. We propose that any revenue in excess of forecasts should be deducted from totex costs entering RAV for the year concerned.

Other system charges (not remunerated through DUoS/metering or other charges)

3.25. This category covers other services in relation to use of the licensee's distribution system at the request of a third party and not made available as part of the normal distribution business. These services therefore fall within the licence definition of "Distribution Business", possibly as a business activity ancillary to the distribution of electricity. They are therefore distinct from activities included under the definition of De Minimis Business. An example would be where a DNO allows telecommunication equipment to be mounted on pylons and derives an income from this use of its assets.

3.26. We propose to retain this category of excluded service for DPCR5 but to improve the wording of the licence definition and guidance in the cost and revenue reporting RIGs to reduce the risk of any misreporting under this heading.

3.27. The appropriate price for these services is likely to be the one which is mutually acceptable to both parties and in those circumstances we would only expect to stipulate that charges should be set be set at a level which will allow the licensee to recover no more than its reasonable costs and a reasonable rate of return in providing the services.

3.28. We propose to deduct DNOs' forecast revenues for this service from DPCR5 price control allowed expenditure and hence from allowed revenue. We also propose that any revenue in excess of forecasts should be deducted from totex costs entering RAV for the year concerned.

Metering excluded services

3.29. At the outset of DPCR4, metering excluded services included only premium metering services, with the basic provision of meter assets and servicing covered by a separate set of metering charge restrictions within the licence. However, since 1 April 2007, as a result of licence modifications, all metering except legacy meter asset provision[7] has been classified under metering excluded services, reflecting the fact that the market for new meter equipment provision and servicing is open to competition.

3.30. DNOs are not obliged to provide meter equipment or servicing (other than legacy meters)[8] and several do not, albeit other providers within their corporate group may do so within the competitive market.

3.31. We consider that it would be appropriate to keep metering (other than legacy meter provision) as an excluded service for DPCR5. Although provision of new metering equipment and services is open to competition we would expect DNO charges for these services to reflect costs and a reasonable rate of return (consistent with the stipulation regarding metering excluded services in the licence prior to the modification referred to above).

3.32. We propose to deduct DNOs' forecast costs (rather than forecast revenues as a proxy for costs) for this service from DPCR5 price control allowed expenditure and hence from allowed revenue. We also propose that any reported costs in excess of forecasts should be deducted from totex costs entering RAV for the year concerned. This treatment reflects our view that it should be easier for DNOs to identify and forecast costs for metering activities than for other categories of excluded services.

[7] Provision of meter equipment in situ on or before 31 March 2007 by the DNO

[8] DNOs do have a licence obligation to connect meters to their networks when requested

Effective incentive rate for RAV adjustments in relation to top up & standby, other system charges and metering excluded services

3.33. The RAV adjustments set out above in respect of revenue in excess of forecasts for top up & standby/enhanced security and other system charges are intended to prevent a DNO being remunerated twice for the same resource provision as illustrated in the hypothetical example below:

Table 3.2 - Example of RAV adjustment for excluded services

	Scenario 1 – no excess excluded services revenue reported	Scenario 2 – excess excluded services revenue reported
Price control allowed expenditure	£100	£100
Forecast excluded services revenue	£1	£1
Reported excluded services revenue	£1	£2
Reported price control expenditure	£100	£100
Allowed price control revenue in NPV terms relating to expenditure for the year adjusted for excluded services (based on IQI incentive rate of 40%)	£100	£99.40
Adjustment amount	-	(£0.60)

Proposals for 'non-relevant' excluded services in DPCR5

3.34. The services of providing connections and diversions are not subject to a RAV adjustment in relation to out-turn revenue levels. Broadly speaking, costs and

revenues for these services are not factored into the price control calculations for allowed demand revenue. This is because we assume the costs are incurred only when the service is called for and the charges for the service are set to recover those costs in full. In their feedback to the May paper DNOs indicated that charges for connections and diversions are set on a 'cost recovery basis'.

New and modified connections

3.35. The price control treatment for new and modified connections in DPCR5 is being separately considered and is not addressed in this section. More information on proposals relating to connections can be found in accompanying papers published as part of the DPCR5 Initial Proposals: 'Incentives and Obligations' (chapter 11) and 'Allowed revenue - Cost Assessment' (chapter 5). It is likely, however, that connections works fully funded by customer contributions will still be categorised as an excluded service in the licence.

Diversion works (non-trading rechargeables)

3.36. In some ways, diversion works are akin to connections works and in the majority of cases customers are obliged to have these works carried out by the DNO. DNOs set charges to recover the costs associated with the required works and we would not expect DNOs to include a margin of return in their charges for diversions except for a reasonable rate of return on capital where costs incurred (in advance of payment by the customer) could be shown to represent an outlay of such capital. This would be consistent with the present (DPCR4) licence stipulation in relation to connection charges. We would also expect DNOs to include relevant information about charges for diversion works in their connections charging methodology or in another readily accessible publication.

3.37. We do not propose to make any changes to the price control treatment of diversion works for DPCR5 although we do intend to improve the wording used in the licence definitions and to keep service standards for diversions under review during DPCR5.

Drafting of licence conditions in relation to excluded services

3.38. We will aim to improve the definitions associated with excluded services in the drafting of licence conditions for DPCR5 by using plainer language and improving references to defined terms. We will also provide additional guidance and examples of items which should and should not be reported under category headings in the cost and revenue reporting RIGs.

Tax allowances in relation to excluded services

3.39. On the basis that excluded service costs and revenues are remunerated by means other than regulated base demand revenues they will not be taken into

account in the setting of tax allowances for price controlled activities (see paragraph 4.24 below). However, any services brought within the scope of the charge restriction conditions for DPCR5 will be brought into account accordingly.

4. Corporation tax allowances

Chapter Summary

The DNOs are limited companies and are obliged to pay corporation tax on their profits. In our calculation of allowed revenues, these profits are represented by the return to the providers of equity finance. There are other elements of the price control where the timing of revenues does not match the timing of costs. Also, tax relief for expenditure may not be on a cash basis, in particular for capital expenditure. As a result we have developed a methodology for calculating a reasonable allowance for DNOs' corporation tax costs.

This chapter sets out our approach to taxation and the tax trigger mechanism we consulted on in the May paper. It covers the methodology for modelling tax and the introduction of a tax trigger mechanism.

Question 1: Do you agree with our position on the tax methodology?

Question 2: Do you agree with the proposal to establish a tax trigger mechanism and that we have established an appropriate balance between incentivising DNOs to manage their tax risks and sharing the risks and rewards with consumers?

Update on methodology

4.1. We set out our policy and methodology for consultation in the May paper. This confirmed our approach for setting ex ante allowances for tax based on a common view of how DNOs' expenditure qualified for tax relief. It also set out our minded to position supporting the introduction of a tax trigger to adjust revenue allowances for material changes in tax legislation. Since then we have held discussions with DNOs on a number of issues they raised. Their principal concerns were:

- The use of DNOs' own forecast opening capital allowance pools and whether some tax relief on costs in DPCR4 would in effect be double-counted because of the DPCR4 regulatory capex allocation methodology.
- The use of a company specific approach (as opposed to a common basis) preferred by Ofgem, for attributing allowable expenditure to capital allowance (CA) pools,
- Transparency and fairness of a common basis approach,
- The treatment of pension costs as qualifying for 100 per cent tax relief in the year of payment, although some DNOs capitalise a portion of pension contributions and receive tax relief in the form of capital allowances over a number of years,

- That the tax trigger mechanism when implemented should include changes in case law and HMRC interpretations from the definition of legislative changes, and

- Whether the adjustments from the tax trigger should be on the whole amount once the trigger event occurs, or just the excess.

4.2. We have considered DNOs' concerns and set out our position on each below. Whilst we have not achieved a consensus on each issue, we consider that our methodology is fair and reasonable and balances the interests (and risks faced) for both consumers and DNOs. An updated methodology statement is at Appendix 3 of this document.

Appropriate opening capital allowance pools

4.3. In modelling the tax treatment of DNOs costs our primary objective is to incentivise DNOs to manage efficiently their tax liabilities. Subject to the tax trigger, they will retain the risk and rewards of doing so. We consider that a DNO's closing balance on each of their capital allowance pools be derived from their submitted corporation tax returns to HMRC and projections for the remainder of a price control period from their FBPQs. It is that position and subsequent allowed revenues and expenditure that will determine the tax burden that customers should fund and not one based on projections at a previous price control.

4.4. Some DNOs have suggested that using the forecast closing tax pools is detrimental to them. Their view is that customers will benefit twice where the modelled tax allowances and actual closing capital allowance (CA) pools are materially different. Such differences arise as the DPCR4 methodology did not follow the statutory treatment of allowing expenditure as deductible for tax but instead followed our own modelling methodology.

4.5. Once allowances are set, it is for licensees to determine the actual pattern and level of expenditure and allocation of resources, not Ofgem. DNOs' tax returns follow their own accounting policies and allocation rules and are not determined by the proposed or previous price control methodologies. The outturn will never match our modelling. One of the reasons we have observed is that there are significant variations between the actual opening CA pool balances and those forecast at DPCR4. Another is the value of the deferred revenue CA pool, which includes fault costs and is allowed against taxable profits at 2 per cent per annum. At that rate, the effect on the tax burden with a 28 per cent tax rate is not material. Another is the capitalising by some DNOs of what we treat as pension costs as if incurred directly by the distribution business (see below).

4.6. DNOs accepted the DPCR4 settlement in the round and we assume must have been comfortable with the allowances, including tax allowances. We do not seek to maintain shadow regulatory data because over time, the balances would diverge significantly and our objective of funding the forecast tax burden arising in a price control period would not be achievable. The DPCR4 tax methodology was applicable

specifically to that review and does not in any way fetter how subsequent controls are determined.

4.7. We still consider that using the DNOs' own forecasts of the opening CA pools at 1 April 2010 is the most appropriate basis to use in modelling the projected tax burden in DPCR5 to be funded by customers. We have also moved to modelling tax based on applying the tax definitions of allowable expenditure and DNOs' own capitalisation policies in setting allowances.

Company specific compared to common allocation basis

4.8. In practice, we recognise that for historic reasons there are variations between the DNOs in the treatment of expenditure on similar items, which we understand have been agreed with HMRC over time. Amending a previous and consistently applied and approved treatment may be difficult. However, applying a common approach has merit in that it aligns the tax treatment of all DNOs' cost categories (as defined in the FBPQ) and follows our consistent approach (in the financial model) of applying the same treatment to each element of costs making up the overall revenue allowance, e.g. WACC, debt, pensions, across licensees.

Attribution to capital allowance pools

4.9. We have received additional data from DNOs on their differing treatment of similar items, which has informed our understanding of why some DNOs were outliers. This has enabled us to revise the percentage allocation of cost categories using the average of DNO allocations, with minimal moderation. We accept this and increased the number of cost categories used to allocate expenditure to CA pools. DNOs suggested, that to improve granularity we use twenty-six categories to determine allocations. In our view this is not feasible and in practise the majority of costs arise in a very limited number of categories. We accept that the non-load category should be split into three, and are now using eight categories in all, which reflect the most significant items affecting the allocations and their consequential impact on the tax burden. A table showing the allocations is in Appendix 3.

Capitalised pension costs

4.10. Some DNOs capitalise a portion of pension contributions and obtain a computational deduction in the form of capital allowances. This arises because the underlying pension cost is incurred in a related party and when incorporated in the charge to the DNO loses its identity as pension costs and is treated as expenditure subject to capital allowance rules. In the hands of the DNO, they receive an annual allowance at 10 per cent of the written down value of the long life pool, not the 100 per cent deduction it would normal enjoy if it were allowed as a pension cost. This also has the effect of increasing the written down value of the opening CA pools on which we forecast future tax liabilities. We have observed that other DNOs have managed this issue more effectively.

4.11. When setting price controls, we treat distribution business as a standalone entity, and we look through related parties to determine the underlying efficient costs. So when modelling tax, we treat this expenditure as if directly incurred in the licensee. We do not accept that we should recognise any apparent detrimental effect arising from the structure of a group of which the DNO is a member. It is for owners of a group of which the DNO is a member to determine their structure, which may or may not be the most tax efficient. It is not for consumers to fund the incremental tax burden arising from a group's structure. Similarly, we do not recognise any tax benefits that DNOs may obtain from a particular group structure.

Definition of legislative changes

4.12. DNOs are concerned that the definition of legislative changes we propose to use in designing the tax trigger does not include changes in case law and HMRC interpretations. They consider that the most significant effect on their tax burden outside of their control was HMRC's revision to the treatment of faults and replacement expenditure following an unrelated tax case in DPCR3. In that instance, they were able collectively to mitigate the effect by obtaining a deferral of the adverse consequential changes until the start of DPCR4. In setting allowances at DPCR4, the effect of this change was acknowledged and modelled in accordance with the revised HMRC guidelines.

4.13. In our and the DNO's view, the trigger mechanism must satisfy certain criteria:

- Removes material risks from legislative changes outside the DNO's control,
- Be unambiguously clear when a trigger event has occurred,
- Be symmetric for both DNOs and consumers,
- Be measurable by Ofgem with minimal recourse to DNOs; and
- Be simple and transparent to apply.

4.14. We recognise that, apart from changes in rates of corporation tax and in capital allowances, the effect of case law and HMRC interpretations has made the single biggest impact on DNOs' tax burden in the last two controls. DNOs acknowledge that they and their wider groups have a direct incentive to challenge changes in case law and interpretation that have a material adverse effect on them using all available means. In deciding the appropriate course to adopt, they will be minded not to harm their reputation and standing with HMRC. There is also the issue that the DNO would have to distinguish its own position from the facts of the case for it to be viable proposition.

4.15. We are sympathetic to DNOs' views and are minded to consider including case law and HMRC interpretations if this satisfies the criteria above. We invite views on how this may be best achieved.

4.16. DNOs acknowledge that de-risking them from adverse uncontrollable material legislative changes should also be reflected in the costs of capital.

4.17. Some respondents have suggested that the adjustments from the tax trigger should be on the excess over a threshold amount rather than whole amount once a trigger event occurs. We agree that this approach would still be symmetrical but, given the proposed trigger point, in our view the adjustment should be on the whole amount.

Tax trigger

4.18. We are strongly minded to adopt a tax trigger mechanism and the methodology is set out in appendix 3.

4.19. Some respondents suggested no minimum level, another 0.25 per cent of price control revenue and others that 0.5 per cent was low for the trigger point. On balance our current view is that the trigger point will be set at 0.5 per cent of price control revenue. This is equivalent to around 20 bps change in RORE. Our final decision will be dependent on the outcome of the RORE discussions and on our view on the cost of capital. We will measure this as the aggregate effect on the tax burden of an individual DNO of all legislative changes within a regulatory year and whether these in total add up to the trigger level. As noted above, the adjustment will be on the whole amount and not just the excess over the trigger point.

4.20. The revision to DNOs' revenues, arising from changes in legislation (including case law and HMRC interpretations), are generally signalled well in advance of their implementation. There is a further timing difference before DNOs' actual cash flows are affected. Respondents to the consultation supported adjustments in the following year (or as soon after as practical). To provide a measure of protection to suppliers, DNOs' revenues will be adjusted in the subsequent regulatory year (or in the following year if this is more practical) to the trigger event.

Determination of opening capital allowance pool balances

4.21. The opening capital allowance pool balances at 1 April 2010 are the DNOs' own forecasts in their FBPQ submissions and as such, we understand are prepared applying the DNOs' own accounting policies, CA pool allocation rules and in accordance with extant legislation. We have reviewed these forecast balances against available evidence and evaluation of open issues with HMRC, where they exist, and have not found it appropriate to make any adjustments. The position will be reviewed again when we have received the annual cost reports for 2008-09.

4.22. We do not specifically intend that account be taken of the 2009 Budget announcement that there will be a one-year increase in first year allowances (from 20 per cent to 40 per cent) for qualifying assets purchased in 2009-10 as it is before DPCR5. We assume DNOs will have factored this into their forecasts of their closing written down values, where significant.

Capitalised indirect costs

4.23. The methodology of using DNOs own capitalisation policies to allocate indirect costs to expenditure subject to the capital allowances has been retained as set out in the methodology appendix. The basis has been updated following discussion with DNOs to more closely reflect their individual methodologies. We will revise as necessary the detailed allocations following a detailed review of the final FBPQ submissions ahead of Final Proposals.

Treatment of excluded services

4.24. All excluded service costs and revenues, including sole use connections are remunerated by means other than regulated base demand revenues. Accordingly, we will ignore these in assessing the tax allowance. However, we will take into account any existing (DPCR4) excluded services brought within the scope of the charge restriction conditions for DPCR5.

Tax allowances in DPCR5

4.25. Forecast tax allowances are shown in the tables for each DNO in Chapter 6. These are the cash payments for tax liabilities, which represent 50 per cent of each of the preceding year and current year tax charges. No allowance is given for movements in provisions for deferred taxation, as this is an accounting construct and has no cash cost.

Tax claw back for excess gearing

4.26. As outlined in the TPCR, GDPCR and DPCR4 final proposals[9] we will implement the ex post adjustment which claws back from licensees the revenue benefit they obtain from lower tax costs because of high gearing.

[9] Electricity Distribution Price Control Review 4 – Final Proposals (265/04)
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=51&refer=Networks/ElecDist/PriceCntrls/DPCR4
Gas Distribution Price Control Review Final Proposals Consultation Document (285/07)
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=362&refer=Networks/GasDistr/GDPCR7-13
Transmission Price Control Review: Final Proposals (206/06)
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=191&refer=Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses

4.27. The clawback will operate, as specified in the relevant Final Proposals, when in any year, (i) actual gearing exceeds notional gearing[10] and (ii) interest costs exceed those modelled at the relevant price control. In the case where both of these conditions are satisfied, we will clawback the tax benefit which results from the difference between actual and modelled interest costs in that year. The specific methodology is set out in our open letter of 31 July 2009.

4.28. The adjustments in respect of DPCR4, which are included in DPCR5 revenue allowances at their present value, affect only three DNOs and are in the table below.

Table 4.1 - Tax clawback adjustments

Clawback - £m	31-Mar-06	31-Mar-07	31-Mar-08	31-Mar-09	31-Mar-10
WPD SWales	0.0	0.0	1.7	2.2	2.0
EDFE SPN	0.7	0.0	0.0	0.0	0.0
EDFE EPN	2.1	0.0	0.0	0.0	0.0

[10] Notional gearing was set at 57.5%, 60% and 62.5% in DPCR4, TPCR and GDPCR

5. Pension costs

Chapter Summary

Pension costs, specifically the costs of providing for defined benefit pension schemes differ from many other types of costs that the DNOs face because they are: more uncertain, in that at the time the obligation is incurred, the costs can only be estimated; more volatile and - for those costs relating to accrued pension liabilities- the DNOs have very limited control. . This is reflected in the large deficits in most DNOs' pension schemes (as with many other UK companies) that have emerged over the last few years. We are consulting separately on our policies for recovery of these costs, but include here a summary of how we have assumed pension costs will be dealt with in arriving at our allowed revenue figures for our Initial Proposals. This includes the true up adjustment for over- and under-funding of pension costs under the DPCR4 settlement. We highlight where there is still work in progress, which will be resolved at Final Proposals and is subject to outcome of the separate consultation on the treatment of pension costs.

We have no questions on pensions as we are consulting separately on this issue. The amounts included in our draft revenue allowances are markers pending the outcome of the consolation and further analysis and review of the data.

Methodology

5.1. For the purpose of modelling allowed revenues we have maintained the methodology used to compute pension cost allowances at DPCR4, subject to their treatment in RAV. At this stage, we are awaiting further data from DNOs in order to inform and then update our analysis.

5.2. Ex ante pension allowances in initial proposals comprise three individual elements:

- Normal ongoing pensions service costs (including pension scheme administration costs and PPF levy),
- Pension deficiency repair payments, and
- Ex post adjustment for over- and under-funding in DPCR4.

Normal ongoing pensions service costs

5.3. As in DPCR4, these are based on the DNOs' own forecast contributions, normalised to reverse the effect of salary sacrifice schemes on the employers' contributions and then applying an efficiency adjustment, using the same percentage we have applied to scale back the DNO forecast of network investment and network operating costs. The risk based element of the PPF levy has been capped at £0.4m

per DNO, pending further work, as most schemes have yet to receive their charges for the last year. The fixed element has been capped at £0.1m.

Pension deficit repair payments

5.4. For Initial Proposals, we have modelled pension costs using DNOs' own estimates of pension deficit repair payments. We have not made a decision on this matter and so this choice should not be treated as our "minded to" position, which we will clarify following our separate pension consultation. The allowances are after applying the relevant regulatory fraction (see below).

5.5. The next triennial valuation for six out of seven of the English and Welsh DNO schemes is at 31 March 2010, and another is due in 2013. The two Scottish schemes and ENW are a year later. Most DNOs schemes have also forecast a further increment to their deficits from at 2013 valuation. We have ignored the latter in our modelling assumption as we consider it is too uncertain an estimate of future movements and too open to challenge.

Determination of regulatory fraction and unfunded ERDCs

5.6. In setting the allowances, we have used the allowed proportion as in DPCR4, where we assumed 80 per cent of most schemes related to the distribution business. We also, in DPCR4, deducted the value of the early retirement deficiency contributions (ERDCs). It is our intention to review and revise these calculations in a price control whenever there is a (i) triennial valuation and (ii) there is a structural change to a pension scheme. We have also set an indicative attributable proportion for SP Distribution and Scottish Hydro Electric Power Distribution, whose schemes were not previously in deficit. These are subject to ongoing review and will be revised for Final Proposals.

5.7. We are still considering the effect of any changes in the unfunded proportion of ERDC amounts agreed at DPCR4. Until we have analysed the data we have retained the DPCR4 ERDC values. There have been a number of structural changes to some schemes and these changes will be incorporated in our assessment for final proposals. All of these proportions are subject to review, are pending receipt of additional data, and will be revised at Final Proposals.

5.8. The relevant proportions retained for initial proposals are :

Table 5.1 - Allowed proportion of pension deficit

DNO	Proportion allowed percentage
CN West	65%
CN East	72%
ENW	92%
CENEDL	75%
CEYEDL	78%
WPD SWest	71%
WPD SWales	75%
EDFE LPN	78%
EDFE SPN	74%
EDFE EPN	100%
SP Distribution	55%
SP Manweb	79%
SSE Hydro	55%
SSE Southern	77%

5.9. EDFE EPN has a 100 per cent allowed since only liabilities relating to distribution members were transferred when the business was acquired by the current owners.

Other conditions

5.10. In considering actual pension contributions, the relevant amounts are the forecast actual cash contributions attributable to the distribution business payable into the relevant pension scheme.

5.11. Actual cash payments for the statutory contribution to the PPF attributable to the distribution business will be allowed as part of normal ongoing service contributions pension subject to the licensee demonstrating that all reasonable steps have been and continue to be taken to mitigate the risk based element of the levy.

5.12. As at DPCR4, we anticipate that companies' actual pension contributions may differ from those projected as part of the price control in response to changing circumstances.

5.13. If we continue with the approach we set out in DPCR4, noting that this approach could chance following the separate pension consultation, the difference between pension contributions and pension allowances in DPCR5 would be offset against future pension costs in determining future pension allowances. Any such adjustments would be net of tax, to the extent that the over- or under- payment has reduced or increased tax payable and the basis will be set out in Final Proposals.

Ex post adjustment for over- and under-funding in DPCR4

5.14. The ex post adjustment to DPCR4 is split into three parts and calculated in accordance with a draft note issued to DNOs in June 2005. Part one is the 57.7 per cent that has been allowed in the indicative annual RAV calculations. The second is the change to the regulatory depreciation relating to part one. The third is the 42.3 per cent amount expensed.

5.15. The amount in the RAV will be funded in future years by way of regulatory depreciation and continue to earn a return equal to the allowed WACC for each review. To the extent that regulatory depreciation was foregone in DPCR4, we allow additional revenue in DPCR5, with a present value adjustment to reflect the delay in revenues. The same approach is taken in respect of the 42.3 per cent expensed. These are both funded in DPCR5 in year one and are calculated net of corporation tax at 30 per cent, being the amount applicable when the DPCR4 allowances were set. The DPCR4 RAV depreciation adjustment will be made in the autumn update.

Table 5.2 - Pensions DPCR4 true up adjustments

£m (2007/08 prices)	DPCR4 opex adjustment	DPCR4 - RAV depreciation adjustment	Total
CN West	4.4	2.3	**6.7**
CN East	3.7	1.5	**5.2**
ENW	8.2	4.7	**12.9**
CE NEDL	0.5	(0.1)	**0.4**
CE YEDL	(0.4)	(0.1)	**(0.6)**
WPD S Wales	1.1	(0.3)	**0.8**
WPD S West	1.5	(0.5)	**1.0**
EDFE LPN	(6.3)	(1.0)	**(7.3)**
EDFE SPN	(8.8)	(1.8)	**(10.7)**
EDFE EPN	(0.5)	(0.1)	**(0.6)**
SP Distribution	3.2	0.0	**3.2**
SP Manweb	10.6	3.8	**14.4**
SSE Hydro	4.0	0.0	**4.0**
SSE Southern	(1.8)	(0.6)	**(2.4)**
TOTAL	**19.3**	**7.8**	**27.1**

6. Revenue allowances and financial modelling

Chapter Summary

This chapter brings together the effects of all our policy decisions on how much revenues the DNOs are allowed to recover. We set out our proposals on the form structure and scope of the price control, explain how we have tested that these represent sufficient revenues for efficient DNOs to finance their businesses, and discuss the profiling of revenues. Finally we set out the total allowed revenues resulting from our initial proposals

Question 1: Do respondents agree that we have appropriately identified the scope of the price control, i.e. are we making allowances for the right categories of costs?
Question 2: How do respondents think we should profile allowed revenues over the 2010-15 period?

Form, structure and scope of the price control

Form of the price control

6.1. We set out in our initial consultation document[11] our intention to continue with the RPI-X form of price control for a five year price control period, from 1 April 2010 to 31 March 2015. We propose to continue to use the RPI index for indexing allowed revenues and RAV during this period.

Profiling of revenues

6.2. Although we express the form of control as an RPI-X control, we are not currently smoothing revenues to produce a consistent X factor for each company, as we have done in previous distribution price controls. Rather, as in GDPCR, we are allowing revenues to change from year to year in line with the underlying cost and return calculations. We have not ruled out applying some revenue smoothing at final proposals, but our final decision will be informed by:

- The impact of a sharp rise in distribution charges in 2010 on consumers in the context of an economic downturn,
- The impact of the depreciation cliff-face on the Scottish companies - this causes a significant fall in allowed revenue in 20011/12. It may be preferable to smooth

[11] Electricity Distribution Price Control Review. Initial Consultation Document (32/08)

this impact over the five year period, as we did with the other DNOs in DPCR3 and DPCR4,

- Financeability concerns - smoothing tends to create a disconnection between revenues and the underlying costs, and so can have an impact on financial ratios, and

- The undesirability of building-in an automatic step up in charges in DPCR6 if we adopt a revenue profile that leaves revenues out of line with the underlying costs in the final year of DPCR5.

6.3. We consider that in the current economic climate, our primary duty to protect consumers means that the first of these factors carries significant weight. The fourth factor reinforces this view. This would entail a profile of gradual increases over the 2010-15 period, although in present value terms, the total revenues would be the same. Subject to assessing the impact of the second and third factor when we develop our final proposals, this is the approach we are minded to take. We welcome stakeholders' views on the most appropriate way to profile revenues.

Structure of the price control

6.4. The proposed structure of the price control comprises:

- DNO base revenue allowances linked to a volume driver on the number of high volume low cost connections involving shared assets that the DNO provides,
- incentive mechanisms that encourage DNOs to:
    - carry out the operation and maintenance of and investment in their networks at an efficient cost,
    - reduce the level of electrical losses and promote energy efficiency;
    - install distributed generation, and
    - improve the quality of service delivered to consumers, particularly in relation to the number and duration of interruptions to supply and the quality of telephone response provided to consumers.
- pass-through for certain specified non-controllable costs (see paragraph 6.4 below),
- a requirement to deliver certain agreed outputs, for which adequate costs have been allowed,
- the low carbon networks fund for carrying out trials of engineering and commercial solutions to the challenges of distributing electricity in a low carbon society,
- a separate fund for continuing innovation on the networks;
- a correction mechanism that adjusts the price control for any previous over or under recovery of revenue, and
- adjustment mechanisms for specific uncertain costs including:
    - changes in tax liabilities (see Chapter 4),
    - pension costs (still under development) (see section 5),
    - Traffic Management Act (TMA) (see the Cost Assessment document),
    - general reinforcement (see the Cost Assessment document), and

- (possibly) the cost of debt (see Chapter 1).

6.5. There are separate price controls proposed for distributed generation and metering.

Pass-through of non-controllable costs

6.6. Ofgem proposes that the price control will pass-through:

- A proportion of transmission exit charges,
- charges from other licensed distributors, covered by their price controls, for the transportation of units to the network of the DNO concerned (wheeling charges),
- variations in network business rates from the costs assumed in setting the price control,
- variations in Ofgem licence fees from the costs assumed in setting the price control, and
- the benefit of any subsidy for areas with high distribution costs.

Over and under recovery of revenues

6.7. We propose that the arrangements for correction factors to deal with over or under recovery of revenues are the same as those in DPCR4. These arrangements are currently operating satisfactorily with under recovery in 2009/10 expected to be within 2 per cent of allowed revenue. Ofgem proposes that the price controls for demand and for distributed generation retain separate correction factors, but that the application of penalty interest rates is based on the net revenue position, determined by the combined effect of the two correction factors, as has been the case during DPCR4.

Bad debt allowances

6.8. In our Best practice guidelines for gas and electricity network operator credit cover[12] document of February 2005 we set out the basis on which network

12 Ref 58/05, http://www.ofgem.gov.uk/Licensing/IndCodes/CreditCover/Documents1/9791-5805.pdf

operators, including the DNOs, could qualify for recovery of bad debts arising from the provision of use of system services. Broadly, the criteria were:

- that the credit cover rules identified as being consistent with best practice had been implemented into the relevant industry codes, and
- that for each specific claim, the network had taken the appropriate steps to minimise their exposure.

6.9. We have received specific applications from two DNOs for recovery of bad debts incurred following the failure of electricity suppliers during the DPCR4 period. We have not yet assessed the validity of these claims against the criteria, or sought equivalent information in respect of costs 'logged up' in RRPs by other DNOs and so have not included any amounts in the revenue allowances at this stage. We will report on this issue in September.

Financial modelling

6.10. We have calculated the baseline allowances set out below using a spreadsheet financial model. This model uses similar calculations to those used in previous price controls and has been shared with the DNOs during its development. We have had the model audited by an external firm (PKF) to ensure its arithmetic accuracy and that its calculations of allowed revenues are consistent with our financial, regulatory and economic assumptions. A version of the model, along with explanatory documentation will be published shortly after this document.

6.11. In addition to this baseline financial model, we have developed a dynamic model that uses Monte Carlo simulation to test a range of price control outcomes depending on some key macroeconomic indicators and DNOs' performance against discretionary incentives. We are using this model to estimate the plausible range of allowed revenues and returns on regulatory equity (RORE), and these results will inform our calibration of the different incentives and risk protection mechanisms in setting Final Proposals.

6.12. We recognise that the results of these sorts of model depend heavily on the assumptions regarding the range, distribution and covariances of the input variables and our analysis is at an early stage. But we still think this is a useful tool to help us to set the overall incentive package and the range of returns available to DNOs and we are working to develop this tool further between Initial and Final Proposals.

Financeability

6.13. We have tested our financial model for each of the DNOs against three key ratios: Funds From Operations ("FFO")/Interest, Retained Cash Flow ("RCF")/Debt, Debt/RAV. These ratios are consistent with those used in previous price control reviews, as are the target values of 3, 9 per cent and 65 per cent respectively. Our

assessment of these initial proposals is that all the DNOs financial profiles for 2010-15 are consistent with a comfortable investment grade under our notional gearing assumption. However, in our financial model, the cost of capital components can have a significant effect on these ratios, and so it will be very important to review the results at final proposals when a decision on the allowed return has been taken.

6.14. Our assessment of financeability is carried out in the round and we do not require that our notional financial model should meet our target values for all ratios in all years. We will meet with major ratings agencies to discuss our approach to financeability before final proposals, which provides us with a useful sense-check on our conclusions. However, we do not seek the rating agencies' approval for our financeability assessment.

6.15. Some of the DNOs have argued that we should specifically target at least an A- credit rating, on the basis that these are difficult times in which to raise capital and that A rated companies are looked on more favourably than BBB rated companies. We do not consider that it is practical to identify a set of target ratios as representing a very specific credit rating, as the credit rating agencies' rating systems allow a broad range of ratio levels for each rating category, and typically do not give different ratios for each notch, they do not provide a different range for BBB+, BBB and BBB-. The rating agencies also take many other factors into account when determining the rating, including the quality of the regulatory framework under which the company operates. We therefore think that a financial profile that meets our target ratios is broadly consistent with an A- rating.

DNO base revenue allowances

6.16. Tables 6.1 to 6.14 demonstrate the calculation of the price control initial proposal allowances and projected RAV roll forward for 2010-15 for each of the 14 DNOs. The calculation of the movement in the RAV is shown on lines 1 to 6. The opening value of the RAV (line 1) is equal to the closing value of the RAV for 2009-10 as set out in Table 2.2 above.

6.17. Capital expenditure - effectively 85% of all network costs, including attributable ongoing pension costs is shown on line 2. This is added to the opening RAV, and the allowed level of depreciation (line 3/line 8) is subtracted from it to give a closing asset value (line 4). The closing value in any year then becomes the next year’s opening value.

6.18. The present value of the closing RAV in each year is shown in line 5. The present value movement in the RAV is then derived by subtracting the present value of the closing RAV from the opening RAV (line 6). Present value calculations involve discounting values by the Vanilla WACC (currently modelled at 5.55 per cent).

6.19. The allowed levels of costs, ex ante incentive expectations and ex post adjustments from the previous price control are shown in lines 7 to 19. Fast pot costs (line 7) include 15 per cent of network costs and 100 per cent of business

support costs. Pension deficit funding is shown in line 9 and fast pot pension costs (15 per cent of pension costs attributable to network costs and 100 per cent of those attributable to business support costs on line 10). Our proposed allowances for corporation tax are set out on line 12. The cash allowance for RAV expenditure in each year is the sum of lines 8 and 11, being the return on the RAV plus the depreciation allowance. This is equal to the sum of lines 2 and 6. Lines 13-15 are the ex post adjustments for DPCR5, in respect of capital expenditure, losses performance and pensions respectively. Line 19 shows the additional income earned or penalty incurred by the company under the information quality incentive (IQI). Line 17 shows our ex ante estimate of allowances under our innovation and low carbon network incentives. Line 21 is the sum of all items in lines 7-19.

6.20. Line 22 is estimated non-controllable costs as set out in paragraph 6.6 above. Line 23 is an estimate of excluded services revenue, which is used as a proxy for the costs attributable to these activities and thus is deducted from the cost base. For this table we have used the DPCR4 approach to the treatment of excluded services, with forecast revenues for the DPCR4 categories of relevant excluded services deducted as a proxies for the costs attributable to these activities. However, we are considering changes to the scope and treatment of excluded services for DPCR5 as set out in Chapter 3 of this document. Line 25 is the sum of lines 21 to 23, and is the total price control revenue allowance. Line 27 shows the percentage change in total allowances from the prior year.

Table 6.1 - CN West allowed revenues

	CN West	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,359.1	1,406.3	1,451.3	1,501.2	1,549.3	7,267.1	1,453.4
2	Total RAV additions	165.2	170.0	178.9	181.6	186.3	882.0	176.4
3	Depreciation	117.9	124.9	129.0	133.5	138.1	643.5	128.7
4	Closing asset value	1,406.3	1,451.3	1,501.2	1,549.3	1,597.5	7,505.6	1,501.1
5	Present value of closing RAV	1,332.4	1,375.1	1,422.4	1,467.9	1,513.6	7,111.3	1,422.3
6	Allowance for change in RAV	27.4	32.1	29.7	34.3	36.6	160.1	32.0
	Allowed costs							
7	Fast Pot	49.5	50.4	52.2	52.7	53.4	258.2	51.6
8	Depreciation	117.9	124.9	129.0	133.5	138.1	643.5	128.7
9	Pension deficit	13.1	13.1	13.1	13.1	13.1	65.7	13.1
10	Pension costs expensed	2.7	2.8	2.8	2.7	2.7	13.7	2.7
11	Return	74.6	77.1	79.7	82.3	84.9	398.6	79.7
12	Tax allowance	21.5	19.9	22.4	24.1	25.9	113.8	22.8
13	Capex Incentive Scheme	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(3.1)	(0.6)
14	Losses Incentive Scheme	(3.6)	(3.5)	(2.8)	0.0	0.0	(9.9)	(2.0)
15	DPCR4 costs	4.7	0.5	0.0	0.0	0.0	5.2	1.0
16	not used							
17	IFI, Innovation & CI/CML	1.5	2.6	3.8	5.2	6.8	20.0	4.0
18	not used							
19	IQI incentive allowance	1.4	1.4	1.4	1.4	1.4	6.9	1.4
20	not used							
21	Total costs	282.7	288.6	301.1	314.5	325.7	1,512.6	302.5
	Price Control Revenue							
22	Pass through costs	32.4	32.9	33.5	34.2	34.8	167.8	33.6
23	Excluded revenues	(4.5)	(4.4)	(4.3)	(4.2)	(4.1)	(21.6)	(4.3)
25	Base price control revenue	310.7	317.1	330.3	344.4	356.4	1,658.8	331.8
25	*check*	310.7	317.1	330.3	344.4	356.4	1,658.8	331.8
26								
27	Change as %age	7.6%	2.1%	4.2%	4.3%	3.5%		4.8%
	DPCR5 20090727.xls							

Table 6.2 - CN East allowed revenues

	CN East	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,308.5	1,357.4	1,405.5	1,468.3	1,523.1	7,062.7	1,412.5
2	Total RAV additions	165.9	171.6	189.1	185.0	184.6	896.2	179.2
3	Depreciation	117.0	123.5	126.4	130.2	133.2	630.3	126.1
4	Closing asset value	1,357.4	1,405.5	1,468.3	1,523.1	1,574.4	7,328.6	1,465.7
5	Present value of closing RAV	1,286.1	1,331.7	1,391.1	1,443.0	1,491.7	6,943.6	1,388.7
6	Allowance for change in RAV	23.0	26.5	14.8	25.9	32.3	122.4	24.5
	Allowed costs							
7	Fast Pot	49.4	50.7	54.1	53.2	52.7	260.1	52.0
8	Depreciation	117.0	123.5	126.4	130.2	133.2	630.3	126.1
9	Pension deficit	17.6	17.6	17.6	17.6	17.6	87.9	17.6
10	Pension costs expensed	2.4	2.4	2.5	2.5	2.5	12.3	2.5
11	Return	71.9	74.5	77.5	80.7	83.6	388.3	77.7
12	Tax allowance	18.0	17.2	19.3	20.1	20.9	95.5	19.1
13	Capex Incentive Scheme	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(8.6)	(1.7)
14	Losses Incentive Scheme	5.4	4.4	0.5	0.0	0.0	10.3	2.1
15	DPCR4 costs	3.9	0.4	0.0	0.0	0.0	4.2	0.8
16	not used							
17	IFI, Innovation & CI/CML	2.5	3.5	4.8	6.3	7.8	24.8	5.0
18	not used							
19	IQI incentive allowance	1.4	1.4	1.4	1.4	1.4	7.0	1.4
20	not used							
21	Total costs	287.7	293.8	302.3	310.2	318.0	1,512.0	302.4
	Price Control Revenue							
22	Pass through costs	43.2	43.9	44.7	45.6	46.4	223.8	44.8
23	Excluded revenues	(6.1)	(6.0)	(5.9)	(5.8)	(5.7)	(29.5)	(5.9)
25	Base price control revenue	324.8	331.7	341.2	350.0	358.8	1,706.4	341.3
25	*check*	324.8	331.7	341.2	350.0	358.8	1,706.4	341.3
26								
27	Change as %age	9.7%	2.1%	2.9%	2.6%	2.5%		4.9%
	DPCR5 20090727.xls							

Table 6.3 - ENW allowed revenues

	ENW	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,227.3	1,260.1	1,304.0	1,345.5	1,357.8	6,494.8	1,299.0
2	Total RAV additions	143.6	160.9	164.1	138.0	143.5	750.1	150.0
3	Depreciation	110.9	117.0	122.6	125.7	128.0	604.1	120.8
4	Closing asset value	1,260.1	1,304.0	1,345.5	1,357.8	1,373.3	6,640.7	1,328.1
5	Present value of closing RAV	1,193.9	1,235.5	1,274.8	1,286.4	1,301.2	6,291.9	1,258.4
6	Allowance for change in RAV	34.3	25.3	30.0	60.7	58.1	208.4	41.7
	Allowed costs							
7	Fast Pot	62.5	66.7	67.5	61.1	62.6	320.4	64.1
8	Depreciation	110.9	117.0	122.6	125.7	128.0	604.1	120.8
9	Pension deficit	6.6	6.6	6.6	6.6	6.6	33.1	6.6
10	Pension costs expensed	5.6	5.7	5.7	5.7	5.7	28.4	5.7
11	Return	67.1	69.2	71.5	72.9	73.7	354.4	70.9
12	Tax allowance	35.5	32.7	35.1	34.4	36.0	173.7	34.7
13	Capex Incentive Scheme	1.4	1.4	1.4	1.4	1.4	7.2	1.4
14	Losses Incentive Scheme	(6.4)	(7.4)	(0.6)	0.0	0.0	(14.4)	(2.9)
15	DPCR4 costs	9.9	1.1	0.0	0.0	0.0	11.0	2.2
16	not used							
17	IFI, Innovation & CI/CML	2.6	4.0	5.6	7.6	9.2	29.0	5.8
18	not used							
19	IQI incentive allowance	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(8.4)	(1.7)
20	not used							
21	Total costs	294.1	295.4	313.8	313.8	321.6	1,538.6	307.7
	Price Control Revenue							
22	Pass through costs	26.6	26.6	26.6	26.6	26.6	133.1	26.6
23	Excluded revenues	(7.3)	(7.5)	(7.6)	(7.8)	(7.9)	(38.1)	(7.6)
25	Base price control revenue	313.4	314.5	332.8	332.6	340.3	1,633.6	326.7
25	*check*	313.4	314.5	332.8	332.6	340.3	1,633.6	326.7
26								
27	Change as %age	17.8%	0.4%	5.8%	0.0%	2.3%		7.2%
	DPCR5 20090727.xls							

Table 6.4 - CE NEDL allowed revenues

	CE NEDL	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	830.8	857.8	882.2	909.4	936.0	4,416.1	883.2
2	Total RAV additions	100.7	102.2	107.5	109.4	105.8	525.5	105.1
3	Depreciation	73.6	77.8	80.2	82.8	85.1	399.7	79.9
4	Closing asset value	857.8	882.2	909.4	936.0	956.6	4,542.0	908.4
5	Present value of closing RAV	812.7	835.9	861.6	886.8	906.4	4,303.4	860.7
6	Allowance for change in RAV	18.5	22.5	21.1	23.2	30.4	115.8	23.2
	Allowed costs							
7	Fast Pot	38.9	39.2	40.7	41.3	40.4	200.5	40.1
8	Depreciation	73.6	77.8	80.2	82.8	85.1	399.7	79.9
9	Pension deficit	15.9	15.9	15.9	15.9	15.9	79.6	15.9
10	Pension costs expensed	1.7	1.7	1.7	1.7	1.7	8.5	1.7
11	Return	45.6	46.9	48.3	49.8	51.1	241.7	48.3
12	Tax allowance	20.5	19.8	21.0	22.2	22.7	106.3	21.3
13	Capex Incentive Scheme	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)	(5.8)	(1.2)
14	Losses Incentive Scheme	(2.3)	(2.5)	2.7	0.0	0.0	(2.0)	(0.4)
15	DPCR4 costs	1.9	1.1	0.0	0.0	0.0	3.0	0.6
16	not used							
17	IFI, Innovation & CI/CML	1.5	2.5	3.6	4.9	6.2	18.8	3.8
18	not used							
19	IQI incentive allowance	1.1	1.1	1.1	1.1	1.1	5.3	1.1
20	not used							
21	Total costs	197.3	202.5	214.2	218.6	223.0	1,055.5	211.1
	Price Control Revenue							
22	Pass through costs	21.6	21.6	21.6	21.6	21.6	108.2	21.6
23	Excluded revenues	(1.6)	(1.5)	(1.5)	(1.4)	(1.4)	(7.4)	(1.5)
25	Base price control revenue	217.4	222.6	234.3	238.8	243.3	1,156.3	231.3
25	*check*	217.4	222.6	234.3	238.8	243.3	1,156.3	231.3
26								
27	Change as %age	14.7%	2.4%	5.3%	1.9%	1.9%		7.0%
	DPCR5 20090727.xls							

Table 6.5 - CE YEDL allowed revenues

	CE YEDL	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,061.8	1,107.6	1,146.4	1,179.5	1,212.6	5,707.9	1,141.6
2	Total RAV additions	139.2	138.3	136.7	140.6	140.4	695.2	139.0
3	Depreciation	93.4	99.5	103.7	107.5	110.8	514.9	103.0
4	Closing asset value	1,107.6	1,146.4	1,179.5	1,212.6	1,242.1	5,888.2	1,177.6
5	Present value of closing RAV	1,049.4	1,086.2	1,117.5	1,148.9	1,176.9	5,578.9	1,115.8
6	Allowance for change in RAV	12.7	22.0	29.7	31.4	36.7	132.6	26.5
	Allowed costs							
7	Fast Pot	51.1	50.3	50.0	51.3	51.4	254.1	50.8
8	Depreciation	93.4	99.5	103.7	107.5	110.8	514.9	103.0
9	Pension deficit	12.0	12.0	12.0	12.0	12.0	59.8	12.0
10	Pension costs expensed	1.9	2.0	2.0	2.0	2.0	9.9	2.0
11	Return	58.5	60.8	62.8	64.5	66.2	312.9	62.6
12	Tax allowance	27.5	26.7	28.0	29.9	30.7	142.8	28.6
13	Capex Incentive Scheme	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(1.4)	(0.3)
14	Losses Incentive Scheme	(3.6)	(6.0)	7.6	0.0	0.0	(1.9)	(0.4)
15	DPCR4 costs	1.0	1.7	0.0	0.0	0.0	2.8	0.6
16	not used							
17	IFI, Innovation & CI/CML	1.1	1.9	2.9	4.3	5.4	15.7	3.1
18	not used							
19	IQI incentive allowance	1.4	1.4	1.4	1.4	1.4	7.0	1.4
20	not used							
21	Total costs	244.0	250.0	270.1	272.7	279.7	1,316.5	263.3
	Price Control Revenue							
22	Pass through costs	28.6	28.6	28.6	28.6	28.6	143.0	28.6
23	Excluded revenues	(3.3)	(3.2)	(3.1)	(3.0)	(2.9)	(15.6)	(3.1)
25	Base price control revenue	269.3	275.4	295.6	298.2	305.4	1,443.9	288.8
25	*check*	269.3	275.4	295.6	298.2	305.4	1,443.9	288.8
26								
27	Change as %age	9.6%	2.3%	7.4%	0.9%	2.4%		5.6%
	DPCR5 20090727.xls							

Table 6.6 - WPD S Wales allowed revenues

	WPD S Wales	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	671.3	674.8	677.9	682.5	686.4	3,392.9	678.6
2	Total RAV additions	72.0	74.3	76.6	76.0	76.6	375.4	75.1
3	Depreciation	68.4	71.2	72.0	72.2	71.7	355.4	71.1
4	Closing asset value	674.8	677.9	682.5	686.4	691.3	3,413.0	682.6
5	Present value of closing RAV	639.4	642.3	646.7	650.3	654.9	3,233.6	646.7
6	Allowance for change in RAV	32.7	33.4	32.1	33.1	32.3	163.7	32.7
	Allowed costs							
7	Fast Pot	31.7	32.4	32.2	31.9	32.2	160.4	32.1
8	Depreciation	68.4	71.2	72.0	72.2	71.7	355.4	71.1
9	Pension deficit	13.1	13.1	13.1	13.1	13.1	65.6	13.1
10	Pension costs expensed	1.3	1.4	1.4	1.5	1.5	7.1	1.4
11	Return	36.3	36.5	36.7	36.9	37.2	183.7	36.7
12	Tax allowance	18.6	17.5	18.5	18.6	18.7	91.9	18.4
13	Capex Incentive Scheme	0.1	0.1	0.1	0.1	0.1	0.3	0.1
14	Losses Incentive Scheme	(2.6)	(0.9)	0.0	0.0	0.0	(3.5)	(0.7)
15	DPCR4 costs	(5.4)	0.0	0.0	0.0	0.0	(5.4)	(1.1)
16	not used							
17	IFI, Innovation & CI/CML	1.4	2.2	3.3	4.3	5.3	16.5	3.3
18	not used							
19	IQI incentive allowance	0.8	0.8	0.8	0.8	0.8	4.2	0.8
20	not used							
21	Total costs	163.8	174.4	178.2	179.5	180.6	876.3	175.3
	Price Control Revenue							
22	Pass through costs	27.9	27.9	27.9	27.9	27.9	139.5	27.9
23	Excluded revenues	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(2.4)	(0.5)
25	Base price control revenue	191.2	201.8	205.6	206.9	208.0	1,013.4	202.7
25	*check*	191.2	201.8	205.6	206.9	208.0	1,013.4	202.7
26								
27	Change as %age	9.1%	5.5%	1.9%	0.6%	0.5%		5.0%
	DPCR5 20090727.xls							

Table 6.7 - WPD S West allowed revenues

	WPD S West	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	914.3	930.7	952.9	975.5	997.8	4,771.1	954.2
2	Total RAV additions	99.7	109.3	111.3	112.9	112.3	545.4	109.1
3	Depreciation	83.3	87.1	88.7	90.5	92.7	442.3	88.5
4	Closing asset value	930.7	952.9	975.5	997.8	1,017.4	4,874.2	974.8
5	Present value of closing RAV	881.8	902.8	924.2	945.4	963.9	4,618.2	923.6
6	Allowance for change in RAV	33.4	28.6	29.5	30.9	34.8	157.1	31.4
	Allowed costs							
7	Fast Pot	40.8	42.9	42.7	43.0	42.9	212.3	42.5
8	Depreciation	83.3	87.1	88.7	90.5	92.7	442.3	88.5
9	Pension deficit	20.9	20.9	20.9	20.9	20.9	104.5	20.9
10	Pension costs expensed	1.6	1.7	1.7	1.8	1.8	8.5	1.7
11	Return	49.8	50.8	52.0	53.2	54.4	260.3	52.1
12	Tax allowance	22.9	20.8	21.9	22.5	23.3	111.5	22.3
13	Capex Incentive Scheme	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.8)	(0.2)
14	Losses Incentive Scheme	(5.9)	(7.4)	0.0	0.0	0.0	(13.3)	(2.7)
15	DPCR4 costs	1.7	0.3	0.0	0.0	0.0	2.0	0.4
16	not used							
17	IFI, Innovation & CI/CML	2.2	3.2	4.4	6.0	7.4	23.2	4.6
18	not used							
19	IQI incentive allowance	1.3	1.3	1.3	1.3	1.3	6.3	1.3
20	not used							
21	Total costs	218.3	221.4	233.5	239.0	244.5	1,156.8	231.4
	Price Control Revenue							
22	Pass through costs	27.9	27.9	27.9	27.9	27.9	139.5	27.9
23	Excluded revenues	(2.1)	(2.1)	(2.0)	(2.0)	(1.9)	(10.1)	(2.0)
25	Base price control revenue	244.1	247.2	259.4	265.0	270.5	1,286.2	257.2
25	*check*	244.1	247.2	259.4	265.0	270.5	1,286.2	257.2
26								
27	Change as %age	13.6%	1.3%	4.9%	2.2%	2.1%		6.3%
	DPCR5 20090727.xls							

Table 6.8 - EDFE LPN allowed revenues

	EDFE LPN	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,217.1	1,261.9	1,307.5	1,344.9	1,363.3	6,494.8	1,299.0
2	Total RAV additions	152.9	160.0	156.5	141.5	139.9	750.7	150.1
3	Depreciation	108.2	114.4	119.1	123.1	125.7	590.4	118.1
4	Closing asset value	1,261.9	1,307.5	1,344.9	1,363.3	1,377.5	6,655.1	1,331.0
5	Present value of closing RAV	1,195.6	1,238.8	1,274.2	1,291.7	1,305.1	6,305.5	1,261.1
6	Allowance for change in RAV	22.1	23.7	34.2	54.6	59.8	194.5	38.9
	Allowed costs							
7	Fast Pot	59.1	60.8	59.8	56.5	56.3	292.6	58.5
8	Depreciation	108.2	114.4	119.1	123.1	125.7	590.4	118.1
9	Pension deficit	30.1	30.1	30.1	30.1	30.1	150.7	30.1
10	Pension costs expensed	1.3	1.3	1.2	1.2	1.2	6.2	1.2
11	Return	66.9	69.3	71.6	73.1	74.0	354.8	71.0
12	Tax allowance	27.3	27.6	29.1	29.2	30.5	143.7	28.7
13	Capex Incentive Scheme	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(11.6)	(2.3)
14	Losses Incentive Scheme	6.1	(6.7)	(0.9)	0.0	0.0	(1.5)	(0.3)
15	DPCR4 costs	(6.3)	0.0	0.0	0.0	0.0	(6.3)	(1.3)
16	not used							
17	IFI, Innovation & CI/CML	2.4	4.0	5.5	7.3	8.9	28.1	5.6
18	not used							
19	IQI incentive allowance	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(1.9)	(0.4)
20	not used							
21	Total costs	292.4	298.1	312.8	317.8	324.0	1,545.2	309.0
	Price Control Revenue							
22	Pass through costs	35.0	35.0	35.0	35.0	35.0	175.1	35.0
23	Excluded revenues	(4.8)	(4.9)	(4.7)	(4.5)	(4.6)	(23.5)	(4.7)
25	Base price control revenue	322.7	328.2	343.2	348.3	354.5	1,696.8	339.4
25	*check*	322.7	328.2	343.2	348.3	354.5	1,696.8	339.4
26								
27	Change as %age	16.1%	1.7%	4.5%	1.5%	1.8%		7.0%
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Table 6.9 - EDFE SPN allowed revenues

	EDFE SPN	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,002.9	1,070.7	1,136.6	1,188.6	1,235.2	5,633.9	1,126.8
2	Total RAV additions	151.1	155.7	146.3	144.8	151.5	749.5	149.9
3	Depreciation	83.2	89.9	94.3	98.2	101.7	467.3	93.5
4	Closing asset value	1,070.7	1,136.6	1,188.6	1,235.2	1,285.0	5,916.1	1,183.2
5	Present value of closing RAV	1,014.5	1,076.9	1,126.2	1,170.3	1,217.5	5,605.3	1,121.1
6	Allowance for change in RAV	(11.9)	(6.3)	10.7	18.8	18.2	29.5	5.9
	Allowed costs							
7	Fast Pot	58.9	61.2	59.1	59.1	60.5	298.7	59.7
8	Depreciation	83.2	89.9	94.3	98.2	101.7	467.3	93.5
9	Pension deficit	23.8	23.8	23.8	23.8	23.8	119.0	23.8
10	Pension costs expensed	1.4	1.4	1.3	1.3	1.4	6.9	1.4
11	Return	55.9	59.5	62.7	65.4	68.0	311.6	62.3
12	Tax allowance	16.0	18.9	19.8	20.7	21.7	97.1	19.4
13	Capex Incentive Scheme	(2.1)	(2.1)	(2.1)	(2.1)	(2.1)	(10.4)	(2.1)
14	Losses Incentive Scheme	14.7	(2.4)	(1.5)	0.0	0.0	10.8	2.2
15	DPCR4 costs	(9.8)	0.0	0.0	0.0	0.0	(9.8)	(2.0)
16	not used							
17	IFI, Innovation & CI/CML	1.2	1.7	2.1	2.6	3.1	10.7	2.1
18	not used							
19	IQI incentive allowance	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(2.0)	(0.4)
20	not used							
21	Total costs	242.8	251.6	259.4	268.6	277.6	1,300.0	260.0
	Price Control Revenue							
22	Pass through costs	11.5	11.5	11.5	11.5	11.5	57.7	11.5
23	Excluded revenues	(2.0)	(1.9)	(2.0)	(1.9)	(1.8)	(9.6)	(1.9)
25	Base price control revenue	252.4	261.2	268.9	278.3	287.3	1,348.0	269.6
25	*check*	252.4	261.2	268.9	278.3	287.3	1,348.0	269.6
26								
27	Change as %age	19.4%	3.5%	3.0%	3.5%	3.2%		8.6%
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Table 6.10 - EDFE EPN allowed revenues

	EDFE EPN	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,676.3	1,764.0	1,834.4	1,892.6	1,934.9	9,102.2	1,820.4
2	Total RAV additions	226.8	219.4	214.4	206.7	217.8	1,085.1	217.0
3	Depreciation	139.1	149.0	156.1	164.4	171.8	780.4	156.1
4	Closing asset value	1,764.0	1,834.4	1,892.6	1,934.9	1,980.9	9,406.9	1,881.4
5	Present value of closing RAV	1,671.3	1,738.0	1,793.2	1,833.3	1,876.9	8,912.7	1,782.5
6	Allowance for change in RAV	5.1	26.7	42.3	61.0	59.6	194.7	38.9
	Allowed costs							
7	Fast Pot	82.5	80.3	79.0	77.5	80.0	399.4	79.9
8	Depreciation	139.1	149.0	156.1	164.4	171.8	780.4	156.1
9	Pension deficit	10.3	10.3	10.3	10.3	10.3	51.7	10.3
10	Pension costs expensed	2.4	2.3	2.3	2.3	2.4	11.8	2.4
11	Return	92.8	97.1	100.6	103.3	105.7	499.4	99.9
12	Tax allowance	24.9	23.5	26.0	28.6	31.9	134.8	27.0
13	Capex Incentive Scheme	(6.4)	(6.4)	(6.4)	(6.4)	(6.4)	(31.8)	(6.4)
14	Losses Incentive Scheme	11.8	(1.9)	(28.9)	0.0	0.0	(19.0)	(3.8)
15	DPCR4 costs	(3.4)	0.0	0.0	0.0	0.0	(3.4)	(0.7)
16	not used							
17	IFI, Innovation & CI/CML	2.6	4.0	5.5	6.7	9.2	28.1	5.6
18	not used							
19	IQI incentive allowance	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(2.8)	(0.6)
20	not used							
21	Total costs	356.2	357.8	344.0	386.2	404.3	1,848.5	369.7
	Price Control Revenue							
22	Pass through costs	40.7	40.7	40.7	40.7	40.7	203.7	40.7
23	Excluded revenues	(3.4)	(3.4)	(3.3)	(3.1)	(3.2)	(16.3)	(3.3)
25	Base price control revenue	393.5	395.1	381.5	423.9	441.9	2,035.9	407.2
25	*check*	393.5	395.1	381.5	423.9	441.9	2,035.9	407.2
26								
27	Change as %age	12.0%	0.4%	-3.4%	11.1%	4.3%		5.1%
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Table 6.11 - SP Distribution allowed revenues

	SP Distribution	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,321.6	1,295.2	1,299.0	1,305.2	1,314.8	6,535.9	1,307.2
2	Total RAV additions	116.1	120.7	124.9	130.4	127.5	619.6	123.9
3	Depreciation	142.5	116.9	118.7	120.8	123.0	621.9	124.4
4	Closing asset value	1,295.2	1,299.0	1,305.2	1,314.8	1,319.3	6,533.6	1,306.7
5	Present value of closing RAV	1,227.2	1,230.8	1,236.7	1,245.7	1,250.0	6,190.3	1,238.1
6	Allowance for change in RAV	97.0	66.2	64.1	61.2	66.6	355.0	71.0
	Allowed costs							
7	Fast Pot	47.1	48.4	48.6	49.7	48.8	242.7	48.5
8	Depreciation	142.5	116.9	118.7	120.8	123.0	621.9	124.4
9	Pension deficit	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Pension costs expensed	1.6	1.7	1.7	1.7	1.7	8.3	1.7
11	Return	70.6	70.0	70.3	70.7	71.1	352.7	70.5
12	Tax allowance	30.3	17.2	18.6	19.7	20.1	105.9	21.2
13	Capex Incentive Scheme	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(8.0)	(1.6)
14	Losses Incentive Scheme	(1.8)	(0.1)	5.8	0.0	0.0	3.9	0.8
15	DPCR4 costs	3.6	0.5	0.0	0.0	0.0	4.1	0.8
16	not used							
17	IFI, Innovation & CI/CML	2.7	3.7	4.4	5.9	7.1	23.9	4.8
18	not used							
19	IQI incentive allowance	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.5)	(0.1)
20	not used							
21	Total costs	295.1	256.4	266.4	266.8	270.1	1,354.8	271.0
	Price Control Revenue							
22	Pass through costs	42.4	42.4	42.4	42.4	42.4	211.9	42.4
23	Excluded revenues	(5.3)	(5.4)	(5.4)	(5.4)	(5.4)	(26.8)	(5.4)
25	Base price control revenue	332.2	293.4	303.4	303.8	307.1	1,539.9	308.0
25	*check*	332.2	293.4	303.4	303.8	307.1	1,539.9	308.0
26								
27	Change as %age	-5.5%	-11.7%	3.4%	0.1%	1.1%		-4.3%
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Table 6.12 - SP Manweb allowed revenues

	SP Manweb	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,123.9	1,186.1	1,238.2	1,294.3	1,334.0	6,176.5	1,235.3
2	Total RAV additions	156.6	153.4	162.7	150.9	149.6	773.2	154.6
3	Depreciation	94.4	101.4	106.6	111.2	114.1	527.6	105.5
4	Closing asset value	1,186.1	1,238.2	1,294.3	1,334.0	1,369.5	6,422.1	1,284.4
5	Present value of closing RAV	1,123.8	1,173.1	1,226.3	1,263.9	1,297.6	6,084.7	1,216.9
6	Allowance for change in RAV	0.1	13.4	12.2	31.2	37.4	94.3	18.9
	Allowed costs							
7	Fast Pot	56.3	55.8	57.5	54.9	54.6	279.1	55.8
8	Depreciation	94.4	101.4	106.6	111.2	114.1	527.6	105.5
9	Pension deficit	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Pension costs expensed	1.9	1.9	1.9	1.9	1.9	9.5	1.9
11	Return	62.3	65.4	68.3	70.9	72.9	339.9	68.0
12	Tax allowance	15.8	9.7	10.5	10.6	10.7	57.3	11.5
13	Capex Incentive Scheme	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(4.9)	(1.0)
14	Losses Incentive Scheme	(5.5)	(6.8)	(0.2)	0.0	0.0	(12.5)	(2.5)
15	DPCR4 costs	11.9	1.4	0.0	0.0	0.0	13.3	2.7
16	not used							
17	IFI, Innovation & CI/CML	1.7	3.0	4.0	5.4	6.7	20.7	4.1
18	not used							
19	IQI incentive allowance	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.7)	(0.1)
20	not used							
21	Total costs	237.6	230.6	247.5	253.7	259.8	1,229.2	245.8
	Price Control Revenue							
22	Pass through costs	26.2	26.2	26.2	26.2	26.2	131.1	26.2
23	Excluded revenues	(4.8)	(4.8)	(4.8)	(4.8)	(4.8)	(24.0)	(4.8)
25	Base price control revenue	259.1	252.0	268.9	275.1	281.2	1,336.3	267.3
25	*check*	259.1	252.0	268.9	275.1	281.2	1,336.3	267.3
26								
27	Change as %age	23.4%	-2.7%	6.7%	2.3%	2.2%		8.6%
	DPCR5 20090727.xls							

Table 6.13 - SSE Hydro allowed revenues

	SSE Hydro	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	847.6	855.7	852.0	846.0	837.5	4,238.8	847.8
2	Total RAV additions	75.7	72.6	72.0	70.8	73.7	364.7	72.9
3	Depreciation	67.5	76.3	77.9	79.4	80.3	381.4	76.3
4	Closing asset value	855.7	852.0	846.0	837.5	830.9	4,222.1	844.4
5	Present value of closing RAV	810.8	807.2	801.6	793.5	787.3	4,000.3	800.1
6	Allowance for change in RAV	37.8	49.8	51.8	54.0	51.6	245.0	49.0
	Allowed costs							
7	Fast Pot	35.4	34.8	34.7	34.3	35.0	174.2	34.8
8	Depreciation	67.5	76.3	77.9	79.4	80.3	381.4	76.3
9	Pension deficit	12.5	12.5	12.5	12.5	12.5	62.5	12.5
10	Pension costs expensed	1.7	1.7	1.7	1.7	1.7	8.5	1.7
11	Return	46.0	46.1	45.8	45.4	45.0	228.3	45.7
12	Tax allowance	18.1	18.4	19.9	20.8	21.7	99.0	19.8
13	Capex Incentive Scheme	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(8.0)	(1.6)
14	Losses Incentive Scheme	1.3	1.2	1.2	0.0	0.0	3.7	0.7
15	DPCR4 costs	4.0	0.3	0.0	0.0	0.0	4.3	0.9
16	not used							
17	IFI, Innovation & CI/CML	1.7	2.7	3.9	5.1	6.4	19.8	4.0
18	not used							
19	IQI incentive allowance	0.8	0.8	0.8	0.8	0.8	4.2	0.8
20	not used							
21	Total costs	187.4	193.3	196.9	198.5	201.8	977.9	195.6
	Price Control Revenue							
22	Pass through costs	37.9	37.9	37.9	37.9	37.9	189.5	37.9
23	Excluded revenues	(1.0)	(1.0)	(0.9)	(0.9)	(0.9)	(4.7)	(0.9)
25	Base price control revenue	224.3	230.2	233.9	235.5	238.8	1,162.7	232.5
25	*check*	224.3	230.2	233.9	235.5	238.8	1,162.7	232.5
26								
27	Change as %age	9.8%	2.6%	1.6%	0.7%	1.4%		4.5%
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Table 6.14 - SSE Southern allowed revenues

	SSE Southern	2010/11	2011/12	2012/13	2013/14	2014/15	DPCR5 Total	5 yr avg
		£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08	£m 07/08
	Regulatory Asset Value (RAV)							
1	Opening asset value	1,674.2	1,708.5	1,736.7	1,764.9	1,786.9	8,671.2	1,734.2
2	Total RAV additions	190.7	192.4	196.1	192.7	185.2	957.1	191.4
3	Depreciation	156.4	164.2	167.9	170.6	171.9	831.0	166.2
4	Closing asset value	1,708.5	1,736.7	1,764.9	1,786.9	1,800.2	8,797.2	1,759.4
5	Present value of closing RAV	1,618.7	1,645.4	1,672.2	1,693.1	1,705.7	8,335.1	1,667.0
6	Allowance for change in RAV	57.0	64.8	66.2	73.8	83.5	345.3	69.1
	Allowed costs							
7	Fast Pot	72.9	73.2	73.7	73.0	71.3	364.1	72.8
8	Depreciation	156.4	164.2	167.9	170.6	171.9	831.0	166.2
9	Pension deficit	43.2	43.2	43.2	43.2	43.2	215.8	43.2
10	Pension costs expensed	3.0	3.0	3.0	3.0	3.0	15.2	3.0
11	Return	91.3	93.0	94.5	95.8	96.8	471.4	94.3
12	Tax allowance	42.6	41.3	44.0	44.0	43.6	215.5	43.1
13	Capex Incentive Scheme	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(4.9)	(1.0)
14	Losses Incentive Scheme	1.6	1.8	1.7	0.0	0.0	5.1	1.0
15	DPCR4 costs	(1.8)	0.5	0.0	0.0	0.0	(1.2)	(0.2)
16	not used							
17	IFI, Innovation & CI/CML	3.4	5.5	7.7	10.0	12.1	38.6	7.7
18	not used							
19	IQI incentive allowance	2.3	2.3	2.3	2.3	2.3	11.5	2.3
20	not used							
21	Total costs	413.9	427.1	436.9	440.9	443.3	2,162.2	432.4
	Price Control Revenue							
22	Pass through costs	68.9	68.9	68.9	68.9	68.9	344.6	68.9
23	Excluded revenues	(2.2)	(2.1)	(2.1)	(2.0)	(1.9)	(10.3)	(2.1)
25	Base price control revenue	480.7	493.9	503.8	507.9	510.3	2,496.5	499.3
25	*check*	480.7	493.9	503.8	507.9	510.3	2,496.5	499.3
26								
27	Change as %age	17.3%	2.7%	2.0%	0.8%	0.5%		6.9%
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Appendices

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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. 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.

1.2. 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

1.3. 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.

1.4. 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.

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

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

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CHAPTER: One

Question 1: Do respondents think that PwC have identified an appropriate range for setting the cost of capital?
Question 2: How should we balance our standard long-term view of the cost of capital with current indicators in the capital markets?
Question 3: Which, if any, of the alternative methods of dealing with variability in the cost of debt should we adopt?
Question 4: What are the pros and cons of the mechanistic debt trigger as suggested by PwC?

CHAPTER: Two

Question 1: Do you agree with the draft rules for computing RAV additions and will they reduce or eliminate boundary issues at DPCR5. If not how should they be amended?
Question 2: In what circumstances would you consider it appropriate to have DNO-specific RAV additions percentages?

CHAPTER: Three

Question 1: Do you agree with our proposal to bring the distribution of units to new EHV premises, provision of charging statements and reactive energy transportation within the scope of the main charge restriction conditions (see paras 3.9 to 3.19 above)?
Question 2: Do you agree that revenue protection services should be exempt from a RAV adjustment where reported revenues exceed forecast revenues and that the definition should make clear that the service only includes work commissioned by a third party?

CHAPTER: Four

Question 1: Do you agree with our position on the tax methodology?
Question 2: Do you agree with the proposal to establish a tax trigger mechanism and that we have established an appropriate balance between incentivising DNOs to manage their tax risks and sharing the risks of rewards with consumers?

CHAPTER: Six

Question 1: Do respondents agree that we have appropriately identified the scope of the price control, i.e. are we making allowances for the right categories of costs? RAV adjustment where reported revenues exceed forecast revenues and that the definition should make clear that the service only includes work commissioned by a third party? (see paras 3.20 to 3.22 below)

Appendix 2 – Regulatory Asset Value Additions

Computing RAV additions

1.1. The regulatory asset value (RAV) is a key building block of the price control review. It represents the residual expenditure by companies from which consumers receive benefit and thus pay for over an extended period of time, and on which the companies earn a return and receive depreciation. It is often used as a measure of the value of the regulated business.

1.2. In developing these proposals, it has been necessary for us to decide which categories and proportions of costs should be included in the RAV of each licensee (treated as capital expenditure), and therefore remunerated over a period of time that exceeds the expected duration of these price controls.

1.3. In order to roll forward the RAV from April 2010 to March 2015, expenditure that the DNOs incur in this period should be treated in the same way as in developing the proposals – that is, the same constituents of costs added to the RAV (i.e. in the slow pot). All costs are cash costs, i.e. they exclude provisions and atypical accruals and prepayments, except the actual cash utilisation thereof.

1.4. In order to perform this calculation it is necessary to define a number of categories of costs which are used in the computation of the "Additions to RAV":

- Network Investment (excluding sole use Connections costs and related customer contributions and Traffic Management Act ("TMA") costs) ,
- Sole use Connections costs and related customer contributions and related indirect activities (but excluding TMA costs),
- Network Operating costs and indirect activities (excluding Business Support),
- Business Support costs,
- Pension costs, and
- Other costs.

Additions to RAV

1.5. We will add 85 per cent of the aggregate of Network Investment, Network Operating costs and indirect activities, including attributable normal ongoing pension service costs to RAV. These categories of costs (and their component activities in

DPCR4), as with all the categories, are intended to be mutually exclusive. Costs added to RAV:

- do not include interest or tax costs (except for business rates on non-operational buildings and stamp duty land tax). Tax costs include corporation tax, capital gains tax, income taxes and network rates,
- are all intended to refer to costs of the distribution business incurred by the licensee or a related party of the licensee, not to recharges between the licensee and a related party, and
- include ESQCR costs.

1.6. The categories of costs and their constituent activities will be as set out in the FBPQ guidance and be refined at Final Proposals and the DPCR5 Price Control Cost Reporting Rules: instructions and guidance respectively[13], and

Less 85 per cent of

- customer contributions (excluding those associated with sole use assets),
- cash proceeds of sale (or market value of intra-group transfer) of both operational and non-operational capex,
- cash proceeds of sale of scrap,
- amounts recovered from third parties in respect of damage to the network,

and **excluding 100 per cent of**:

- pension deficit repair funding costs (and for the avoidance of doubt, all unfunded early retirement deficiency costs (ERDC) post 1 April 2004),
- normal employer ongoing pension contributions related to the provision of non-relevant excluded service costs[14] and unregulated activities,
- all metering expenditure,

[13] These will be published on the Ofgem website and are an enduring document subject to annual update

[14] Non-relevant excluded services are services funded by charges to the party requiring the service / works where no ex ante adjustment has been made to costs allowances in respect of forecast activity levels

- all depreciation and amortisation,
- business support costs,
- profit margins from related parties (except as defined below),
- all costs falling within the distributed generation scheme (except as an agreed transfer from the DG mechanism) and any residual costs from the DPCR4 RPZ incentive scheme,
- costs in relation to pass-through items including business rates, Ofgem licence fees, Shetland balancing costs, NTR costs, wheeled units, and all transmission exit charges,
- relevant excluded services costs (except for the true up between projected and outturn costs – see below),
- fines and penalties incurred by the DNO (including all tax penalties and fines and interest),
- compensation payments made in relation to standards of performance,
- TMA costs,
- lane rentals,
- any costs to the extent that they are allowed for under the uncertainty adjustment arrangements in special licence condition A3,
- all costs logged up, e.g. costs logged up by agreement between the DNO concerned and Ofgem in relation to undergrounding in national parks or areas of outstanding natural beauty,
- costs falling within IFI,
- costs falling within the low carbon networks fund,
- bad debt costs and receipts (subject to an ex post adjustment),
- any costs relating to asset revaluations, and
- costs of undertaking de minimis activities.

and **reversing**:

- any provisions and accruals (i.e. non-normal level of trading costs) to ensure costs are on a cash basis (subject to not creating boundary problems between different price control periods).

Definitions

1.7. Each category will be as defined in detail in the annual Price Control Cost Reporting Rules - Instructions and Guidance prepared and amended in accordance with standard licence conditions 48 and 49.5 respectively.

1.8. Network Investment (excluding customer contributions[15]) is defined as:

- Load related expenditure - costs associated with new system assets connected by the DNO to the network because of a new connection, system reinforcement associated with shared-asset connections and general reinforcement of the network due to an increase in demand; and specifically excluding sole use connections (the latter are an excluded service). (Note: General reinforcement costs are the costs associated with new or upgraded system associated due to an increase in demand.);

- Non-Load New and Replacement Asset expenditure: The installation of new assets and the planned installation of replacement assets other than for load-related reasons, including expenditure on high impact low probability (HILP) events, flood defences, quality of services, environment, BT 21st Century expenditure.

1.9. Network Operating costs are defined as:

- Network Operating costs, comprising the following activities – inspections and maintenance, fault repair, tree cutting and non-operational capital expenditure, including all storm related costs (inspection and storm damage repair) less related insurance recoveries; and

- Indirect activity costs defined as - engineering indirect comprising the following activities – engineering management and clerical support, mapping, control centre, call centre, stores, health and safety, project management and network design.

1.10. Business Support costs are defined as the costs of carrying out the following activities (as defined in the Cost Reporting rules) – CEO costs, finance and regulation, network policy, property, information systems and insurance costs and insurance claim receipts (as negative) except those related to storms.

[15] Customer contributions are financial contributions received from a customer in respect of the provision of a new connection to the DNO's network.

1.11. A sole use connection is defined as expenditure on connection assets for the sole benefit of the party being connected and which are fully chargeable to the party being connected. It includes the direct and indirect cost of providing connections to new customers, which are wholly funded by customer contributions, and excludes shared service connections, i.e. direct and indirect cost costs and margin less contributions.

1.12. The scope and treatment of excluded service costs and revenues are under review (see Chapter 3) and subject to the outcome, the following approach will be taken:

- Costs associated with 'relevant' excluded services (using forecast revenues as a proxy) will be deducted from allowed operating costs and hence from allowed revenues in a similar way as they were for DPCR4, and
- A proportion of the amount of any revenue in excess of forecast amounts for relevant excluded services will be deducted from totex entering RAV during DPCR5.

1.13. Pension costs are defined as the cost to the employer of normal ongoing pension service costs, including pension administration costs and the Pension Protection Fund levies; and pension deficit repair costs.

1.14. Other costs are any other economical and efficiently incurred costs of the distribution business not specifically defined above.

Other conditions

Efficient costs

1.15. Ofgem reserves the option to disallow costs from any of these categories if they do not relate to the distribution business or are demonstrably inefficient or wasteful.

Related party costs

1.16. Costs are only included to the extent they represent the cost of services required by the distribution business, i.e. if not provided by the group, the licensee would need to procure the services separately. Ofgem will expect the services and associated costs to be itemised and justified. Such costs are only included to the extent that they satisfy the criteria regarding the prohibition of cross subsidy at standard licence condition 4.9.

1.17. All companies and related parties charging the licensees should be able to demonstrate they have a robust and transparent framework governing the

attribution, allocation and inter-business recharging of revenues, expenses, assets and liabilities. There should be documented procedures to demonstrate compliance with EC Procurement directives.

1.18. Related parties should be able to justify the charge by reference to external benchmarking; or by reference to market related testing; or tendering. All charges must be supported by either Service Level Agreements or contracts; and contracts should be finalised on a timely basis and not remain as drafts.

1.19. Attributions of costs and of shared services must be demonstrated to be performed on an objective basis not unduly benefiting the regulated company or any other company or organisation and be based on levels of service or activity consumed by each entity. The basis should be documented and approved at board level, assessed, and challenged annually, which should be evidenced.

1.20. The basis should be consistent from year to year and where there are changes they should be both documented and justified.

1.21. The method used to attribute costs should be transparent and the revenues, costs, profits, assets and liabilities separately distinguishable from each other.

Restated costs

1.22. For all costs, in whatever category, activity or exclusion, any costs restated will be applied in the year in which the cost was incurred rather than the year of the restatement.

Shared use connections

1.23. It is the amount of direct costs of shared use connections and attributable business support costs, net of customer contributions, to which the RAV addition percentage will apply and the attributable support costs will be excluded from total business support costs.

Related party margins

1.24. Related party profit margins will be excluded from the definitions above unless the related party concerned earns at least 75 per cent of its turnover from sources other than related parties and charges to the licensed entity are consistent with charges to external customers. For this purpose, an entity will be considered to be a related party if it is in the same group as the DNO (be it a holding company, affiliate, subsidiary, associate, joint venture) or if that entity and the DNO have any other form of common ownership. A key indicator of entities being in common ownership is that they are affiliates of the ultimate controller, (or controllers where there is more than one).

1.25. With the exception of a principal related party resource provider, when an entity ceases to be a related party, for example on a change in ultimate controller, then from the moment it ceases to be a related party its margins will be allowable, with one proviso. That is, there is an unambiguous demonstration that its charges to the distribution business (in the original or amended contract) remain competitive and are in line with market rates, or until the contract is re-tendered and there is more than one bidder.

1.26. On a principal related party resource provider[16] ceasing to be a related party during a price control period, for example on the restructuring of a group, it shall continue to be treated as a related party until the end of that price control period and the margins charged will be disallowed. At the next price control period the proviso in the preceding paragraph that their charges should be demonstrated as remaining competitive will apply to subsequent review periods.

1.27. Whilst not precluding other demonstrations of competiveness, we consider that an open competitive tender is likely to be the clearest example and absent of this, we will require clear reasons for not re-tendering.

1.28. Irrespective of whether competition is demonstrated and margins no longer disallowed, the licensee must arrange to comply with the requirements of standard licence condition 48 (on the maintenance and provision of information). It must continue to report the former related party's costs and margins on a basis consistent as if were a related party for the remainder of the price control period. The data is required in order for us to maintain our dataset.

1.29. Related party margins of a captive insurance entity ("captive"): These will be treated the same as any other related party margin and disallowed. DNOs and their affiliates will be required to maintain such accounting and other records (as specified in standard licence conditions 44.4 and 48.2(a)[17] to identify this amount. Where an affiliated captive incurs a loss, for example resulting from an excess of claims over premiums by the distribution business in any given year the loss will be allowed as an additional cost, subject to not being double counted in subsequent periods. Where adequate records are not kept, by either the affiliate or the DNO, to identify the DNOs share of premiums, claims, administrative expenses, movements on

[16] A principal related party resource provider is one that has a contract to operate or manage a substantial part of a licensee's day-to-day operations, which was entered into before or as part of the arrangements for a change in ultimate controller, or controllers where there is more than one.
[17] In 1 June 2008 revision of the Electricity Distribution Licence.

IBNR[18] and technical reserves; and any other costs, then the total premiums and any losses will be disallowed.

Interaction with the distributed generation incentive

1.30. The distributed generation incentive will not include any capital expenditure or associated indirect costs already included in RAV additions and where capital expenditure is incurred for the benefit of both demand and generation, costs shall be apportioned accordingly.

1.31. Where related assets are not used by generators but are used by demand customers, the DNO concerned may, by agreement with Ofgem, transfer the undepreciated value of capex to the RAV.

[18] IBNR – incurred but not received.

Appendix 3 Statement of tax methodology

Tax methodology

1.1. The proposed methodology was consulted on in the May consultation paper and we set out in this appendix the methodology applied in the financial modelling for initial proposals.

1.2. The distribution business is modelled for price control purposes as a standalone entity. All expenditure is treated as if it is incurred directly by the distribution business.

Applicable tax regime

1.3. We will apply the UK standard tax rules that have passed into legislation by the time of the Final Proposals. These Initial Proposals reflect the current legislative position.

1.4. All capital allowances are assumed to be claimed at rates in line with applicable legislation and claimed in the year the expenditure is incurred.

Tax losses

1.5. If tax losses arise we will not give affected DNOs negative tax allowances, but we will log up any tax losses as calculated on a regulatory basis and deduct them from expected tax allowances when the timing differences that led to the loss reverse.

Modelling of capital allowances

1.6. For DPCR5, we apply a common approach to allocate allowed expenditure to capital allowance pools. This relies on an 'average' actual allocation based on the information we have received from the DNOs with limited moderation based on our view of where capex should go according to the standard tax rules.

1.7. There are two common allocation tables:

- one for DNOs who were party to an agreement with HMRC, which in effect created a separate "deferred revenue" capital allowance pool for defined replacement and fault costs, and
- one for the two DNOs that were not party to that agreement and who do not allocate any expenditure to this pool.

1.8. We use four main capital allowance pools – General, Long Life, Industrial Buildings Allowance (IBA) and Deferred Revenue and the relevant rates of annual writing down allowance. These reflect the relevant legislation in place at the DPCR5 review and take into account the legislative changes to the capital allowances regime since DPCR4. We have reflected the phasing out of IBAs. We also allow for expenditure that is identified as non-qualifying (NQ) for capital allowances, principally easements being interests in land.

1.9. Where identified expenditure qualifies for either Research & Development Allowances or as environmentally beneficial technologies it will be allowed at the enhanced rates. Following discussion with the DNOs, we have concluded that DNOs do not have any costs which would qualify for environmental remediation allowances. We will review this should such costs arise.

1.10. All other expenditure not qualifying for capital allowances nor treated as non-qualifying will attract a 100 per cent deduction.

1.11. The annual allowance for deferred revenue will be 2 per cent straight-line, based on the average economic lives of all DNOs relevant assets at 51 years.

1.12. Based on our current analysis of data, our firm view is to apply the following allocation basis of the key building blocks to the capital allowances pools:

Table 1 – Cost allocation to capital allowance pools

	General pool	Longlife	IBA	Deferred Revenue	Revenue	Non-Qualifying
DNOs party to non-load agreement						
Load Related	0.8%	92.4%	3.0%	2.9%	0.0%	0.9%
Asset replacement	0.0%	19.0%	3.0%	78.0%	0.0%	0.0%
Other Non-Load Related	18.5%	34.9%	7.7%	38.9%	0.0%	0.0%
Other Network operating costs (inc I&M)	0.0%	1.4%	0.0%	8.6%	90.0%	0.0%
Fault repairs and restoration	0.0%	3.0%	0.0%	65.0%	32.0%	0.0%
Tree cutting	0.0%	18.0%	0.0%	14.0%	68.0%	0.0%
Non Operational Capex	90.1%	2.3%	0.8%	0.1%	0.0%	6.7%
Easements	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
DNOs not party to non-load agreement						
Load Related	0.0%	98.1%	1.9%	0.0%	0.0%	0.0%
Asset replacement	0.0%	93.2%	6.8%	0.0%	0.0%	0.0%
Other Non-Load Related	17.5%	80.1%	2.4%	0.0%	0.0%	0.0%
Other Network operating costs (inc I&M)	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Fault repairs and restoration	0.0%	75.2%	0.0%	0.0%	24.8%	0.0%
Tree cutting	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Non Operational Capex	85.6%	0.0%	0.0%	0.0%	0.0%	14.4%
Easements	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%

Opening capital allowance pool balances

1.13. We have used the forecast opening capital allowance pool balances brought forward at 31 March 2010 provided by DNOs. These have been calculated based on the DNOs' own accounting policies / tax allocation rules without adjustment.

1.14. We have not adjusted the forecast opening plant and machinery pools for the 2009 Budget announcement that there will be a one-year increase in first year allowances (from 20 per cent to 40 per cent) for qualifying assets purchased in 2009-10.

Capitalised indirect costs

1.15. We use individual DNO-specific capitalisation policies to determine the treatment of indirect costs and to these we apply the attribution rates to capital allowance pools set out the table above.

Modelling the tax deductibility of pension costs

1.16. The cash payments made by the DNO into a pension scheme are 100 per cent deductible in the year incurred, except where there are large irregular payments. The latter should be spread over the current and up to three future years in accordance with the legislation, dependent on their magnitude.

1.17. For modelling and allowance setting, we assume that all pension payments attributable to the distribution business (including that related to relevant excluded services, but not necessarily non-relevant excluded services, distributed generation or metering) are paid in the year in which the allowance is given (to take account of the spreading of deficit repair costs). Ex post pension adjustments relating to DPCR4 have been computed net of tax and will not attract any further tax relief.

Modelling cash flows of Corporation Tax (CT) payments

1.18. All DNOs are large companies under tax legislation and are required to pay their tax liabilities for any given year in instalments commencing in the current year. We will assume that half the annual charge to CT is paid in the regulatory year, and half in the subsequent year, regardless of the actual timing of payments by DNOs, (which could be affected by a statutory year end different from the regulatory year end of 31 March, for example) and ignore subventions for surrendered tax losses. We take no account of additional payments (or receipts) from settling earlier years' tax liabilities. For the first year of the price control, we include 50 per cent of the DNOs' estimated tax liability for the previous year, subject to a reasonableness review.

Interest (payable and receivable)

1.19. Interest receivable/payable is modelled by applying the nominal rate of interest (the assumed cost of debt plus modelled RPI estimate) to net debt as determined by the financial model, on an accruals basis. Interest is treated for tax purposes as fully deductible / taxable in the period in which it arises, subject to the tax clawback.

Tax treatment of incentives

1.20. We have modelled all incentive revenues or penalties on a pre-tax basis (i.e. it is not intended that they give rise to further revenues in respect of the tax charge in the revenues). This includes adjustments in respect of capital expenditure incentives.

Treatment of excluded services

1.21. We have made no allowance or relief for tax in respect of excluded service costs and revenues, including sole use connections. In setting ex ante allowances the costs attributable to these services are deducted from the cost base of providing use of system services.

Tax Trigger mechanism

1.22. The trigger mechanism is to be symmetrical and measurable and fulfil the following key criteria, in that:

- it protects DNOs from material effects on their cashflows of legislative changes,
- is unambiguously clear when a trigger event has occurred,
- is symmetric for both DNOs and consumers,
- is measurable by Ofgem with minimal recourse to DNOs; and
- is simple and transparent to apply.

It will be calculated by re-running the DPCR5 financial model to assess the impact on the tax allowance component of revenues on the basis of the average annual effect over the remainder of the price control period of changes in relevant legislation whether introduced in a finance act, other act of parliament, statutory instrument or other legislative instrument. The trigger will specifically exclude

effects arising from:

- changes in, or clarifications to, HMRC interpretation of legislation, or
- new precedents set under case law, and
- any changes that alter the cash tax charge for the DNO in the current price control period that arise specifically because of the DNO being a member of a

group of companies. That is, the tax legislation will be applied as if the DNO were a standalone entity. For example, the potential restriction of interest as deductible as a result of the licensee being a member of any group of companies or partnerships will be not be a trigger event, and

- for the avoidance of doubt, any changes in accounting standards that have a knock-on effect on the quantum or timing of taxation will not be considered as a trigger event.

Trigger point

1.23. The trigger point is a change or changes that yield a greater than 0.5 per cent increase or decrease in the total base revenue of an individual DNO, on the basis of the average annual effect over the remainder of the price control period.

1.24. Consequent upon the prescribed legislative changes above, the DPCR5 model would be re-run to calculate whether the new outcomes activate the trigger. No adjustment will be made to any other assumptions used in the model. This is to ensure that any adjustment is calculated on a like-for-like basis.

1.25. The trigger point is set at 0.5 per cent of total base revenue, and the measurement of this will be the aggregate affect on the tax burden of an individual DNO of all legislative changes within a regulatory year; and whether these in total breach the trigger. The adjustment will be on the whole amount and not just the excess over the trigger point.

Timing of revised revenues.

1.26. When the trigger is activated, changes to DNOs' revenues will take effect from the regulatory year subsequent to that in which the trigger event or events occurred.

Appendix 4 – 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.19

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 accordingly20.

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 them21;
- 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.22

19 Entitled "Gas Supply" and "Electricity Supply" respectively.
20 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.
21 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[23] 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[24] 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.

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

Appendix 5 - Glossary

123

132 kV

Only covers assets at the 132 kV voltage level.

A

Annual Survey of Hours and Earnings (ASHE)

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

Asset replacement expenditure

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

Atypical Costs

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

B

Base case expenditure

Any expenditure that is not discretionary.

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.

BETTA

British Electricity Trading and Transmission Arrangements.

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.

Business Support Costs (BSCs)

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

BT 21st century networks (BT21CN)

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

C

Capital Expenditure (Capex)

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

Customer interruptions (CIs)

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

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

Customer minutes lost (CMLs)

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

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

D

Data envelopment analysis (DEA)

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

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.

Distributed Generation (DG)

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

Distributed Generation Incentive (DGI)

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

Discretionary expenditure

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

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.

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.

E

Early Retirement Deficiency Contributions (ERDCs)

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

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

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

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.

European Union Emission Trading Scheme (EU ETS)

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

Ex ante

Refers to a value or parameter set down before the commencement of the price control period.

Ex post

Refers to a value or parameter ascertained after the commencement of the price control period.

Extra High Voltage (EHV)

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

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.

Feed-In Tariffs

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

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 networks (GDNs)

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

Gas Distribution Price Control Review (GDPCR)

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

General reinforcement expenditure

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

Gigawatt (GW)

A measure of energy equal to one thousand megawatts.

H

Health Indices (HI)

Her Majesty's Revenue and Customs (HMRC)

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

Idok

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

Incremental losses expenditure

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

Independent distribution network operators (IDNOs)

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

Innovation Funding Incentive (IFI)

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

Interruptions Incentive Scheme (IIS)

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

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

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

Information Quality Incentive (IQI)

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

Investment grade credit rating

For the purposes of the initial proposals means a rating at or above the levels shown below:

Standard & Poor 's Ratings Group	BBB-
Moody's Investors Service Inc	Baa3
Fitch ratings Ltd	BBB-

K

Kilowatt (KW)

A measure of energy equal to one thousand watts.

L

Legal and Safety expenditure

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

Load Indices (LI)

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

Load related expenditure (LRE)

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

Low Voltage (LV)

All voltage levels up to and including 1kV.

M

Megawatt (MW)

A measure of energy equal to one thousand Kilowatts.

Modern Equivalent Asset Value (MEAV)

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

N

National Grid Electricity Transmission (NGET)

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

Net demand customer specific expenditure

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

Net present value (NPV)

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

Net present value (NPV) neutral

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

Network 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.

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.

P

Pass through (of costs)

Costs for which companies can vary their annual revenue in line with the actual cost, either because they are outside the DNO's control or because they have been subject to separate price control measures

R

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.

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.

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.

Resource provider

A party related to the DNO which provides significant operational services to the DNO (which could extend to running the whole of the distribution system) to allow it to carry out its distribution activities.

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.

S

Slow money

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

T

Time Fixed Effects Approach

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

Time Series Data Regression Technique

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

Transmission Price Control Review (TPCR)

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

Triennial valuation (pensions)

A detailed actuarial review of a pension scheme's assets in comparison to its liabilities in present value terms. It is used to determine ongoing contributions and any deficit recovery plan.

Trigger

A mechanism to re-set allowed revenue levels when certain criteria are satisfied – intended to address uncertainties present when allowances are initially set

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.

V

Vanilla WACC

The weighted average cost of capital using a pre-tax cost of debt and a post-tax cost of equity. In our financial modelling, it is the figure we use to calculate the cash return on the RAV.

W

Weighted Average Cost of Capital (WACC)

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

Z

Zero Carbon Homes

The government's zero-carbon homes policy, set out in the Housing Green Paper, "Building a Greener Future", proposes that all new homes in England should be zero-carbon from 2016.

Appendix 6 - 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:

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

1.2. Please send your comments to:

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