ofgem Promoting choice and value
for all gas and electricity customers

Gas Distribution Price Control Review Final Proposals

Document Type: Decision Document

Ref: 285/07

Date of Publication: 3 December 2007

Target Audience: Consumers and their representatives, gas distribution networks (GDNs), independent gas transporters (IGTs), gas shippers and suppliers and any other interested parties

Overview:

The current price controls, which specify the maximum revenue that each GDN can recover from its customers, expire on 31 March 2008. This document sets out our final proposals for the gas distribution price controls that will apply to each of the GDNs for the five year period from 1 April 2008.

Our final proposals, which are the culmination of two years work, have been built up from detailed analysis based on GDNs' actual costs. We have used this, together with further analysis and judgements about the efficient level of cost which GDNs will incur over the next five years, to reach a view on the appropriate level of allowed revenue. We are satisfied that our final proposals are a package that, including the associated incentives, fulfils our principal objective to protect the interests of gas and electricity customers and allows GDNs to finance their activities.

GDNs in total will be allowed to recover on average £2,470 million (in 2005-06 prices) for each of the next five years. This is equivalent to a 2 per cent increase above the rate of inflation (or RPI+2). For the average domestic customer this represents a real increase of approximately £2 per annum.

Contact name and details: Joanna Whittington, Director - Gas Distribution

Tel: 020 7901 7046

Email: GDPCR@ofgem.gov.uk

Team: Gas Distribution

Context

In May 2007 we published our initial proposals on the operating, capital and replacement expenditure required by the GDNs and hence the allowed revenues for the five year period from 1 April 2008. We also set out our proposals on a range of incentives and quality of service outputs. In September 2007 we published our updated proposals on the required operating, capital and replacement expenditure, provided some updates on the proposed incentives. We also consulted on the comparative risk analysis we had carried out and the potential impact that this might have on cost of capital.

This is our final proposals document which pulls together all the work undertaken to date including the previous six consultation documents. It sets revenue allowances for each of the GDNs for the five year period from 1 April 2008.

There are no further documents planned but there will be further consultation on the form of the modifications to the GDNs' licences and the Gas (Standards of Performance) Regulations to bring effect to the final proposals. Statutory and licence consultations will be undertaken in February 2008.

Associated Documents

- Open letter on Ofgem's proposals to implement revised standards of performance arrangements for Gas Transporters, November 2007 (Ref. 279/07);
- Leakage and Shrinkage Baselines for 2008-13, October 2007 (Ref. 256/07);
- Capacity outputs incentive for GDPCR, October 2007 (Ref. 254/07);
- GDPCR Updated Proposals, September 2007 (Ref. 226/07);
- GDPCR Initial Licence Drafting Consultation (Ref. 221/07);
- GDPCR Cost Reporting Consultation (Ref. 185/07);
- GDPCR Initial Proposals, May 2007 (Ref. 125/07);
- GDPCR Fourth Consultation, March 2007 (Ref. 49/07);
- GDPCR One Year Control Final Proposals, December 2006 (Ref. 205/06);
- GDPCR Third Consultation, November 2006 (Ref. 203/06);
- GDPCR One Year Control Initial Proposals, September 2006 (Ref. 169/06);
- GDPCR Second Consultation, July 2006 (Ref. 123/06);
- GDPCR Initial Consultation, December 2005 (Ref. 259/05).

Table of Contents

THIS PAGE IS INTENTIONALLY LEFT BLANK

Summary

Our principal objective is to protect the interests of gas and electricity consumers. In the context of gas distribution networks (GDNs) we do this by periodically reviewing the revenue which GDNs are allowed to recover from their customers and by establishing a framework that creates incentives for GDNs to operate efficiently, deliver an agreed quality of service, contribute to sustainability and meet their statutory obligations and licence conditions.

Our final proposals, which are the culmination of two years work, have been built up from detailed analysis based on GDNs' actual costs. We have used this, together with further analysis and judgements about the efficient level of cost which GDNs will incur over the next five years, to reach a view on the appropriate level of allowed revenue. We are satisfied that our final proposals are a package that, including the associated incentives, fulfils our principal objective and allows GDNs to finance their activities.

GDNs in total will be allowed to recover on average £2,470 million (in 2005-06 prices) for each of the next five years. This is equivalent to a 2 per cent increase above the rate of inflation (or RPI+2). For the average domestic customer this represents a real increase of approximately £2 per annum. Individual allowances for each of the GDNs are set out in the table below.

£m in 2005-06 prices		Allowed revenue 2007-08	Average annual allowed revenue 2008-13	Average increase (%)
NGG	East of England	427.2	430.5	0.3
	London	245.1	282.1	4.9
	North West	285.5	299.0	1.6
	West Midlands	217.8	231.7	2.1
NGN	Northern	273.5	290.3	2.0
SGN	Scotland	194.3	201.5	1.2
	Southern	432.4	468.1	2.7
WWU	Wales and West	252.0	267.3	2.0
	Total	2,327.7	2,470.4	2.0

In determining our final proposals we have assessed the efficient level of operating expenditure (opex) required by each GDN using a combination of bottom up benchmarking of specific activities and top down benchmarking of total opex. Since updated proposals, published in September, we have made a number of small adjustments to the way in which benchmarking has been carried out. More materially we have increased our estimates of those costs which are expected to increase by more than RPI. We have not changed our view that an efficiency assumption of 2.5 per cent per annum applied to opex is appropriate. The net effect of these changes has been to increase our forecast opex from updated proposals by £36 million per annum or 6 per cent.

This is the first time, following the sale of four of the GDNs by NGG in 2005, that we have been able to make use of meaningful comparisons between GDNs. At the next review in five years time we expect the importance of benchmarking to increase still further. In the meantime we are confident that our ability to establish benchmarks

based on comparisons of separately-owned GDNs has allowed us to set revenue allowances at a significantly lower level than would otherwise have been the case.

We have addressed areas of new costs where the amounts and timing are uncertain by either agreeing to reopen the price control when the level of costs is clearer (Traffic Management Act compliance costs) or setting a revenue driver (increased costs of providing the emergency service following the potential loss of meter work). Our capital expenditure (capex) assessment incorporates a number of changes which has led to a small increase in capex of £20 million per annum. Our replacement expenditure (repex) assessment incorporates a number of changes which have the effect of increasing repex by £26 million per annum. The table below summarises these changes before and after the application of the Information Quality Incentive which increases our forecasts by a further 2 per cent. In total our proposals provide for more than £5 billion in investment over the five year period.

	2002-07	2007-08	Average annual amounts 2008-13				
£m 2005-06 prices	Average actual	One year control	GDN Forecast	Updated Proposals (pre-IQI)	Final Proposals (pre-IQI)	Final Proposals (post-IQI)	Difference to GDN forecast
Opex	656.5	652.5	723.6	628.0	663.8		-8%
Capex	260.7	358.4	396.2	319.2	339.1	345.2	-13%
Repex	491.9	588.0	787.5	678.6	704.4	722.0	-8%

For our final proposals, we have calculated the allowed revenue using a vanilla cost of capital of 4.94 per cent (equivalent to a post tax cost of capital of 4.3 per cent). We continue to base the allowed return on equity on a long term view of total market returns. Taking into account a number of other factors, including our view that the price control for the GDNs is at least as risky as that for transmission, we have set the cost of equity at 7.25 per cent. Our view on the cost of debt remains unchanged since updated proposals at 3.55 per cent.

We have reviewed the performance standards which GDNs are required to deliver and are proposing a number of changes which will provide a simpler package of measures for monitoring quality of service, with tougher standards in some cases. We have also proposed a number of incentives which will reward GDNs for making their businesses more sustainable. This includes: a new incentive to reduce gas leakage based on the shadow price of carbon; an Innovation Funding Incentive targeted at sustainable development; and a Discretionary Reward Scheme targeted at GDNs who reduce their environmental impact, facilitate the extension of networks to alleviate fuel poverty and raise awareness of gas safety including the dangers of carbon monoxide (CO). In addition we have identified changes to GDN charging structures which if implemented could facilitate extensions to the network to fuel poor communities. We have proposed that further work is carried out on whether changes in operating practices by Emergency Service Personnel attending a gas emergency could reduce the risk of future deaths and injury caused by CO poisoning.

We have asked the GDNs to let us know by 7 January 2008 whether they are minded to accept our proposals. If they do, we will undertake a further statutory consultation early next year to introduce them from 1 April 2008. If any company decides not to accept the proposals, we expect to refer the matter to the Competition Commission.

1. Introduction

Chapter Summary

This chapter sets out the background and structure of the document.

Background

1.1. The price control that currently applies to the GDNs expires on 31 March 2008. The GDPCR will reset the revenue allowances for the eight GDNs for the next price control period, 1 April 2008 to 31 March 2013.

1.2. We started working on the price control review in December 2005 with the publication of our initial consultation document. In May 2007 we published our initial proposals, followed in September by our updated proposals which took into account actual 2006-07 cost data, revised GDN forecasts for expenditure, further analysis on areas that we had not completed in time for initial proposals and changes that we had made in light of responses to our May consultation. We have now reviewed the responses to updated proposals and have made a number of further changes in light of these.

1.3. In our initial proposals and updated proposals we set out a range of incentives, including a number focussed on sustainable development, which together with the proposed allowances we consider will best protect consumers' interests.

1.4. GDNs have the individual opportunity to decide whether to accept or reject the proposals set out in this document. If they decide to accept the proposals, we will undertake statutory and licence consultations early next year leading to the implementation of the price control on 1 April 2008. If any company decides not to accept the proposals, we expect to refer the matter to the Competition Commission.

Structure of this document

1.5. This consultation document is organised as follows:

- Chapter 2 details our view on the form, structure and scope of the price control;
- Chapters 3 and 4 set out our thinking on the future operating, capital, and replacement expenditure requirements of the GDNs. Chapter 4 also includes the effect of the information quality incentive on allowed revenues;
- Chapter 5 sets out our proposals on quality of service and also our proposed approach to sub-deduct networks;

- Chapter 6 sets out our proposals for rolling incentives, a mains replacement incentive, a capacity outputs incentive and a loss of meter work revenue driver;
- Chapter 7 details our proposals in the area of sustainable development. In particular it sets out the shrinkage incentive, a new leakage incentive which focuses on the environmental impact from gas leakage, an innovation funding incentive for sustainable development, our network extensions proposals and a proposed discretionary reward scheme;
- Chapter 8 provides our proposals for the funding of xoserve and the arrangements for independent systems;
- Chapter 9 details our proposals for the cost of capital, tax, and our assessment of financeability;
- Chapter 10 draws together our analysis in order to outline the overall impact of Ofgem's proposals; and
- Chapter 11 details the next steps for the review and associated workstreams.

1.6. There are a number of supplementary appendices which provide more detail on our final proposals. In addition, appendix 4 sets out how we have responded to points made by respondents to our updated proposals. Appendix 2 provides a glossary of terms relevant to this document.

2. Form, structure and scope of the price control

Chapter Summary

This chapter sets out our final view on the form, structure and scope of the price control.

Revenue Drivers

2.1. In the 2002-07 price control 35 per cent of the GDNs' allowed revenue varied with gas throughput on the network. The rationale for a throughput-based revenue driver (or volume driver) was that the costs of operating the network increase as the overall capacity requirements increase and that changes in throughput would reflect changes in capacity (which cannot be directly independently measured).

2.2. In the previous price control period throughput did not grow steadily as forecast but fluctuated in response to weather and gas prices. This fluctuation did not trigger changes to peak demand and hence changes in capacity. Gas shrinkage and odorant costs do vary with throughput. Odorant costs typically account for less than 0.2 per cent of revenues. Gas shrinkage costs are recovered through a separate incentive mechanism.

Ofgem's decision

2.3. As a result of this analysis we have decided not to include a volume driver in this price control.

2.4. We also consulted on whether it would be appropriate to include any other revenue drivers. We concluded that there was limited merit in a capacity related or customer related revenue driver but suggested that a connections driver may be appropriate. In general, GDNs did not support any of these revenue drivers and considered that a connections related revenue driver would be difficult to implement in practice. Shippers had mixed views on whether a connections related revenue driver was appropriate. In light of these responses we have decided not to include any revenue drivers other than our proposals in relation to loss of meter work which is discussed further in chapter 6.

Scope of the price control

2.5. We have consulted on changes to the scope of the price control and the treatment of a number of excluded services and pass through items. In particular, consideration has been given to a number of inter-transporter services that GDNs provide or receive. In most cases these services are covered by consents which were obtained as part of GDN sales and will expire by 1 April 2008.

2.6. A number of these services are provided on a temporary basis, for example under the System Operation Managed Services Agreement (SOMSA) and the Front Office Managed Services Agreement (FOMSA). We do not propose to include these services within the licence and the GDNs will need to seek consent from the Authority for any extension of these arrangements.

2.7. The other significant service is the emergency call handling service which is currently provided by NGG for all the GDNs and IGTs. In light of the importance of the emergency call handling arrangements and the technical limitations on many licensees operating a single telephone number, it appears more practical to maintain the current arrangements. It is proposed that the emergency call handling services NGG provides to the IDNs and IGTs are included within the licence as an excluded service for NGG. We propose to retain the provision of the emergency service to consumers on IGT networks as an excluded service for all GDNs at this time. We will monitor through cost reporting the charges levied by NGG and how they have changed over time. There are other services smaller in scale that are not described above which we propose to treat on a case by case basis.

2.8. In responses, GDNs have also raised Post Emergency Metering Services (PEMS) as a potential excluded services. We consider that PEMS constitute a metering activity and given that excluded services cover activities that are undertaken by GDNs as part of transportation activity but do not fall within the price control, PEMS do not need to be detailed as excluded services.

Price indices

2.9. We consulted on whether we should link some or all of allowed revenues to a price index other than the Retail Price Index (RPI). There was broad support among respondents for the continued use of the RPI. A few of the respondents considered that some revenue could be linked to other indices or that real price effects, e.g. those associated with contractor rates and material costs, should be incorporated into the allowances.

2.10. For reasons set out in the second consultation document, in particular the difficulty of identifying an alternative price index sufficiently reliable and yet not in itself influenced by the GDNs, we continue to support the retention of the RPI as the key price index. We do not propose to link any cost allowances to alternative cost indices, apart from gas shrinkage. The cost allowances and efficiency targets that we have set take account of real growth in input prices, including contractor and materials costs.

Dealing with uncertainty, new obligations and costs

2.11. Initial proposals set out a specific reopener to allow for additional costs arising as a result of implementation of the Traffic Management Act 2004 (TMA) if no further developments occurred before updated proposals to provide greater clarity on the cost impact. We are still not in a position to make a provision for an efficient level of cost for TMA but we recognise that GDNs will be putting in systems in anticipation of its introduction from the start of this price control. In calculating the revenue allowances we have included £11.3 million of additional capital expenditure in recognition of these costs. We also propose to include TMA as a specific reopener so that any costs are considered in isolation from the GDNs' financial performance under the price control. We propose to follow the approach utilised in DPCR4 to manage the uncertainty associated with TMA. The reopener will also apply to the additional capital expenditure now included in revenue allowances.

2.12. We propose no change to our approach of a specific reopener to manage the potential risk of a change in tax treatment. Further detail on both these specific reopeners will be set out in the forthcoming second licence drafting consultation. We propose to use a materiality threshold of 1 per cent of revenue cumulative through the price control period in each case before a reopener is triggered.

Correction mechanism

2.13. The correction mechanism adjusts the price control for any previous over or under recovery against allowed revenues. We set out our intention in initial proposals to implement a two tier recovery mechanism similar to that introduced for DPCR4 but with a larger deadband of 3 per cent rather than 2 per cent. The mechanism imposes a higher penalty on companies that incur large over-recoveries compared to small over-recoveries. The deadband is the range in which the company suffers a lower interest rate.

2.14. There was general support for this approach but responses argued that gas demand is more sensitive to changes in weather than electricity and so it is harder for GDNs to recover accurately their allowed revenue. GDNs suggested that a deadband of plus or minus 4 or 5 per cent was appropriate.

2.15. We agree that there is evidence to support greater volatility in gas demand for weather changes and a larger deadband is appropriate. However there are a number of different factors that feed into changes to forecast allowed revenue and recovered revenue for both electricity distribution and gas distribution. For example, we noted in initial proposals some of this underlying volatility is diminished in gas distribution by the proposed removal of the volume revenue driver. On balance we consider a deadband of 3 per cent is appropriate.

2.16. We also note the GDNs' proposed charging modification to change the capacity/commodity split[1]. Such a proposal would have the potential to reduce significantly the volatility in GDN income. If this or similar proposals come to Ofgem and are approved such that the ability of GDNs to recover more accurately their allowed revenue is greatly improved, we would consider adjusting the correction mechanism to reduce the deadband.

[1] DNPC03 LDZ System Charges - Capacity / Commodity Split and Interruptible Discounts (www.gasgovernance.com)

3. Operating expenditure analysis

Chapter Summary

This chapter sets out our final proposals for operating expenditure taking into account responses received to updated proposals, ongoing analysis, and further information received from the GDNs.

Introduction

3.1. In October 2006, we received responses to our Business Plan Questionnaires (BPQs) from each of the GDNs setting out their historical operating costs (opex) for 2005-06 and forecast opex for 2006-07 to 2012-13.

3.2. We appointed a number of consultants to review GDNs' operating costs including:

- Europe Economics to carry out a benchmarking exercise of total controllable opex and Total Factor Productivity (TFP) analysis to estimate the scope for efficiency savings for gas distribution as a sector;
- PB Power to review the direct operating activities together with capex and repex (discussed in chapter 4); and
- LECG to review the indirect opex (support service) activities.

3.3. Together with our consultants we reviewed the GDNs' BPQ submissions and raised supplementary questions to gain a better understanding of the GDNs' data and to gather additional information to support the cost assessment. Together with LECG and PB Power we visited each of the GDNs in order to discuss their BPQ submissions, ask follow-up questions and challenge and improve our understanding of the GDNs' forecast assumptions. The consultants then carried out detailed cost analysis to provide initial recommendations to Ofgem on the appropriate levels of opex.

3.4. We summarised this work in our March consultation document and consulted on both the methodology and the results.

3.5. In our initial proposals published in May we set out our opex assessment for each GDN based on our consultants' analysis and further work by ourselves to consider the GDNs' BPQ responses, their initial views on the PB Power reports and our own assumptions for regional factors, productivity and real input price growth.

3.6. Following initial proposals we appointed Reckon LLP to carry out additional work on the scope for ongoing operating costs efficiencies including updating the earlier Europe Economics worked based on new data and reviewing the work that First Economics had carried out on behalf of the GDNs.

3.7. Our updated proposals, published in September 2007, took account of actual cost information received for 2006-07 as well as comments received on our approach and proposals set out in the initial proposals document. We also included additional costs for a number of areas where our analysis was not complete at the time of initial proposals. This included £13.6 million per annum to cover training and apprentice costs to meet the skills gap that has been identified and £6.1 million per annum of additional regional costs associated with working in low or high customer density areas.

3.8. This chapter sets out our final proposals for opex taking into account responses received to updated proposals, ongoing analysis, and further information received from the GDNs.

Summary of our final proposals opex assessment

3.9. For final proposals we have taken the analysis from updated proposals and made a number of changes to take account of comments received and further work we have carried out. Details of these changes are set out below and in appendix 5.

3.10. Table 3.1 sets out a high level summary of our final proposals for opex by GDN. It shows both our updated proposals and final proposals.

Table 3.1 - Summary of our final proposals opex assessment

Updated Proposals Average Annual Total Opex assessment (excluding shrinkage) 2008-09 to 2012-13 (£'m 2005-06 prices)

	NGG				NGN	SGN		WWU	Total GDN	Average annual GDN Allowance
Total Opex Asessment 2008-09 to 2012-13	East of England	London	North West	West Midlands	Northern	Scotland	Southern	Wales & West		
Direct Cost	61.0	48.9	50.7	38.2	50.9	42.0	81.4	48.2	421.4	52.7
Indirect Costs	23.7	13.4	18.6	14.2	16.8	13.7	20.6	17.2	138.3	17.3
Adjustment to top down	5.3	3.9	4.3	3.3	4.2	3.5	6.3	4.1	34.8	4.4
Quality of Service	0.4	0.6	0.2	0.2	0.3	0.2	0.4	0.2	2.5	0.3
SIU costs	0.0	0.0	0.0	0.0	0.0	0.7	0.1	0.0	0.9	0.1
Training and apprentice allowance	2.1	1.2	1.6	1.1	1.6	1.7	2.5	1.7	13.6	1.7
Environmental remediation	0.9	0.9	0.9	0.9	1.0	0.5	0.5	2.3	8.1	1.0
Waste management costs	0.4	0.3	0.3	0.2	0.2	0.2	0.5	0.2	2.4	0.3
Non-labour regional factors	0.0	1.9	0.0	0.0	0.0	1.0	1.2	2.0	6.1	0.8
Total	**93.9**	**71.2**	**76.7**	**58.1**	**75.1**	**63.6**	**113.6**	**75.9**	**628.0**	**78.5**

Final Proposals Average Annual Total Opex assessment (excluding shrinkage) 2008-09 to 2012-13 (£'m 2005-06 prices)

	NGG				NGN	SGN		WWU	Total GDN	Average annual GDN Allowance
Total Opex Assessment 2008-09 to 2012-13	East of England	London	North West	West Midlands	Northern	Scotland	Southern	Wales & West		
Direct Cost	63.2	50.9	52.6	39.7	53.8	43.6	84.8	50.3	438.8	54.9
Indirect Costs	26.6	14.7	20.7	15.7	17.5	13.9	21.0	17.7	147.7	18.5
Adjustment to top down	5.6	4.1	4.6	3.4	4.4	3.3	6.6	4.2	36.3	4.5
Quality of Service	0.4	0.6	0.2	0.2	0.3	0.2	0.4	0.2	2.5	0.3
SIU costs	0.0	0.0	0.0	0.0	0.0	0.7	0.1	0.1	1.0	0.1
Training and apprentice allowance	2.2	1.3	1.7	1.2	1.7	1.8	2.6	1.8	14.4	1.8
Environmental remediation	0.9	0.9	0.9	0.9	1.0	0.5	0.5	2.3	8.1	1.0
Waste management costs	0.4	0.3	0.3	0.2	0.2	0.2	0.5	0.2	2.4	0.3
Capex/opex trade-off	2.1	1.2	1.6	1.3	0.0	0.0	0.0	0.0	6.2	0.8
Sub-deduct network surveys	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.4	0.0
Non-labour regional factors	0.0	1.9	0.0	0.0	0.0	1.0	1.2	2.0	6.1	0.8
Total	**101.4**	**76.1**	**82.7**	**62.6**	**79.0**	**65.3**	**117.7**	**78.9**	**663.8**	**83.0**

3.11. The analysis we have carried out to benchmark opex across GDNs and forecast future levels of expenditure has delivered efficiency savings for customers in this review. As well as real growth in input prices, there are a numbers of areas where the outputs GDNs are required to deliver are increasing or there are other external pressures on costs. For example we are forecasting additional costs associated with training and apprentices, increasing waste charges and taxes and increased pension contribution rates. The net impact of our efficiency analysis and these other changes is a 2.1 per cent increase between 2006-07 actual costs and our average annual assessment for 2008-09 to 2012-13.

3.12. Adjusting for the impact of the additional costs in areas where outputs are changing, we estimate that there is a 3.1 per cent reduction between 2006-07 actual costs and our average annual assessment for 2008-09 to 2012-13.

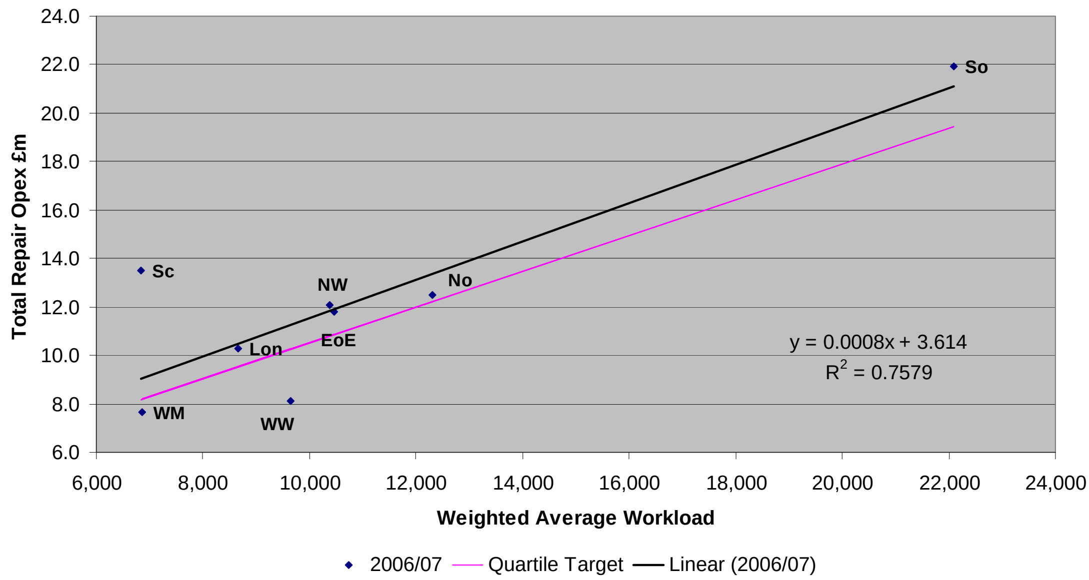
Approach

3.13. This is the first time, following the sale of four of the GDNs by NGG in 2005, that we have been able to make use of meaningful comparisons between GDNs. At the next review in five years time we expect the importance of benchmarking to increase still further. In the meantime we are confident that our ability to establish benchmarks based on comparisons of separately-owned GDNs has allowed us to set revenue allowances at a significantly lower level than would otherwise have been the case.

3.14. Our overall approach in this review has been to assess the efficiency of the GDNs by benchmarking the efficiency of individual activities within direct and indirect operating cost areas wherever practical and carrying out more specific analysis for those areas where benchmarking was not practicable or did not provide sufficiently robust results. Applying the method of top down regression typically used to assess opex in previous price controls, would use only eight (or possibly four if ownership groups are used) data points. In addition, given the timing of GDN sales, this approach would have the added disadvantage of only two years of data against which to determine any trend. We consider, in these circumstances, that it is more appropriate to carry out our assessment at an individual activity level as this allows us to make use of more data points and allows more in depth consideration of the cost drivers associated with each activity than analysing operating costs at a total level.

3.15. As an example, on direct opex, for the repair activity PB Power based its analysis on a regression of GDNs' actual costs using a weighted average of the number of repairs as the cost driver. PB Power also adjusted the GDNs' forecast for the number of repairs to take account of the impact of the mains replacement programme. The regression is shown in figure 3.1 below.

Figure 3.1 – Repair regression 2006-07 actuals



3.16. The costs were benchmarked based on the upper quartile level of performance (i.e. the lower cost GDNs) and then rolled forward to take account of the forecast number of repairs, our assumption on ongoing efficiencies and real growth in the cost of contract labour, direct labour and materials.

3.17. A more detailed explanation of our analysis for each of the direct operating activities - work management, emergency, repair, maintenance, and other direct opex - is set out in appendix 5.

3.18. We also assessed indirect opex at an individual activity level. For example, LECG assessed property management costs by comparing GDNs against each other on the basis of levels of floor space (normalised for the size of GDN by looking at floor space per kilometre of pipe-line) and facilities management costs per square foot of property. Rental costs for individual properties have been benchmarked against local data, leading to further adjustments for some GDNs.

3.19. A more detailed explanation of our analysis for each of the support service activities is set out in appendix 5.

3.20. We recognise that a potential weakness with benchmarking at the upper quartile level of costs for each individual activity is that it creates a benchmark that is not currently achieved by any GDN. We have addressed this by applying an uplift on our disaggregated cost forecasts based on the average difference between our disaggregated benchmarks and the top-down opex benchmarks based on the upper quartile level of performance. This is explained in more detail in paragraphs 3.29 to 3.35.

3.21. In practice our combined approach of making use of both disaggregated and top-down analysis means that the overall level of allowances is determined by the top-down analysis but the detailed benchmarking determines the allocation of allowances between the GDNs.

3.22. In initial proposals we explained that we had considered applying a glidepath to benchmarked opex to allow GDNs some time to achieve the targets we set. However we did not feel that this was appropriate because the difficulty of achieving opex targets has been offset by the uplift to top-down benchmarks. Also applying glidepaths gives greater increases in allowances to the least efficient companies. We remain of the view that glidepaths are not appropriate.

Key issues raised in response to updated proposals

3.23. This section sets out the key issues relating to operating expenditure raised in the responses to updated proposals, our response to these and the resulting impact on our costs. We address the detailed issues on opex, the concerns raised by NGG on opex-capex trade-offs and then the appropriate assumptions for real input price growth and ongoing efficiency savings. Further details are set out in appendix 6.

Overall methodology

Respondents' views

3.24. WWU considers that our bottom-up benchmarking approach is flawed and we should move to a top-down approach, adjusting for the impact of economies of scale for NGG, removing NGN because of its failure in 2006-07 to meet the prescribed level of performance for attending gas escapes within 1 hour and SGN because it receives some services from SSE at marginal cost.

3.25. It considers that our indirect opex benchmarking is flawed because of the use of revenue as a scale variable, which distorts the performance comparisons between GDNs and external comparators. WWU considers we should base our approach on external benchmarks using more appropriate cost drivers.

3.26. NGN considers that a frontier performer should get a higher allowance in the base year than its actual costs. NGN notes that in updated proposals no GDN other than Southern is getting more than its actual costs in 2006-07. It considers that this results in weak incentives for efficiency. It suggests a number of ways of addressing this including differentiating the level of uplift on our bottom-up forecasts based on levels of efficiency.

Ofgem's decision

3.27. We do not consider it is appropriate to change our overall approach to setting opex in the light of comments we have received. We consider that given the lack of a historical track record it would be inappropriate to rely purely on a top-down approach as the bottom-up analysis allows us to make use of more data points and consider the drivers underlying each activity in more depth.

3.28. We do not consider it is appropriate to apply different levels of uplift on our bottom-up forecasts based on relative levels of efficiency for different GDNs. Our bottom-up cost assessment captures relative levels of efficiency and the most efficient GDNs will receive higher opex as a result.

Total opex regression and uplift

Respondents' views

3.29. The GDNs have highlighted inconsistencies in the customer numbers used in our overall opex regression. The numbers for SGN and NGN included customer numbers on IGT networks whereas NGG and WWU excluded these customers.

3.30. Some GDNs were concerned about the impact of SSE providing services to SGN at marginal costs on our top-down analysis and the calculation of the uplift we applied to our bottom-up forecasts. These GDNs noted that in our bottom-up indirect opex analysis we had accepted the arguments that the marginal cost pricing created unsustainable benchmarks, so we had moved from upper quartile benchmarks to benchmarks based on the second lowest cost company. They argue that since SGN is also influencing the upper-quartile benchmark in the overall opex analysis, we should make a similar adjustment to this benchmark.

3.31. In its response to updated proposals SGN stated that the overarching umbrella Managed Service Agreement (MSA) effectively covered the fixed costs of the services SSE provide. SGN considered that it was inequitable for it to be penalised because of the alleged marginal cost pricing issue. It considers its allowances for indirect opex should be set on the same basis as for the other GDNs, either based on the upper quartile level of performance or based on the second best GDN.

3.32. Of the non-GDN responses, one felt that relaxing from frontier to upper quartile would not be sufficient to adjust for distortions in the bottom-up benchmarking, two welcomed the relaxation to upper quartile and two disagreed with it.

Ofgem's decision

3.33. We have re-run our total operating cost analysis using consistent customer numbers and including other changes to the bottom up analysis. This reduces the uplift factor on our bottom-up forecasts from 6.22 per cent to 6.13 per cent.

3.34. There has been a lack of clarity from SGN on the pricing of support services provided by SSE to SGN under their MSA. At the initial costs visits as part of the review it highlighted that services were being provided at marginal cost and that the avoided costs were a synergy benefit for consumers. The other GDNs have pressed us to adjust our overall benchmarking to address this as they suggested this would lead to unsustainable benchmarks. SGN is now arguing that it receives a fair allocation of costs from SSE and the umbrella service agreement covers the fixed costs. On balance given this uncertainty we consider it is appropriate to continue to make an adjustment to the bottom-up analysis to address this issue and as such we will also need to make an adjustment to the top down analysis for consistency.

3.35. We have added an additional £1.5 million to SGN’s costs in the total opex regression to cover an estimate of the additional fixed costs relating to SSE’s support services. This is based on 25 per cent of the value of the MSA contract. The impact of including this in the regression is to increase the uplift factor by 0.74 per cent to 6.87 per cent and increase total opex by 0.59 per cent.

Detailed opex issues

3.36. The GDNs raised a number of issues with our updated proposals where they believed that there were errors in our methodology or calculations. We have reviewed these items, some of which were differences in judgement or opinion rather than methodology and calculation errors, and have amended our calculations accordingly.

Respondents' views

3.37. The IDNs have highlighted that there will be an increase in emergency call handling costs from 2007-08 onwards due to NGG increasing its charges for providing this service. NGG noted that it provided a discount as part of the call handling charges up to 2006-07 and that the revised charges reflect a full allocation of costs plus a normal commercial margin for bearing the risk associated with the work. It argued that the work management benchmarks are understated because they reflect the discount for emergency call handling in the IDNs’ costs.

3.38. NGG considers that we have made an error in the roll forward of the IS benchmarks. LECG determined an efficient level of IS expenditure as a proportion of revenue based on an average of NGG’s forecasts, which included a 4 per cent per annum efficiency saving. We then applied NGG’s forecast profile of costs to this resulting in the efficiencies being double counted. NGG also argues that it is inappropriate for us to apply our 2.5 per cent ongoing efficiency assumption to these costs, which already include more stretching efficiency assumptions.

3.39. NGG and WWU have argued that there are errors in the bottom-up maintenance analysis. They note that some of their non-routine maintenance costs have been inappropriately left in the routine maintenance benchmarking and have therefore been disallowed. They suggest that there were atypically low costs for a number of maintenance activities in the base year 2006-07 that results in unsustainable benchmark costs for future years.

3.40. NGG considers that benchmarking human resource (HR) costs by looking at the number of HR full time employees (FTEs) as a proportion of direct employees is more a measure of outsourcing strategy than HR efficiency. It considers that overall HR costs per FTE is a more appropriate measure.

3.41. The GDNs and xoserve have identified a number of issues with the calculation of the xoserve opex forecasts including that the benchmarks should be based on the performance of the second best company group consistent with the way the GDNs' costs had been assessed and that 11 per cent of efficiency savings and user pays costs should be allocated to NGG NTS. They have also argued that it is inappropriate to apply benchmarks from the GDNs to xoserve due to the different nature of their businesses and highlighted inconsistencies in the opex figures to which the efficiency savings were being applied.

3.42. NGG has noted that there are gas holder demolitions driven by safety, operational or environmental considerations that are not associated with property disposals. NGG said that we should make provision for such costs.

3.43. NGG and WWU suggested that there were some outstanding normalisation issues that needed to be addressed related to SGN and WWU's costs.

3.44. Overall NGG has argued that our "errors" have resulted in our opex forecasts for its GDNs being understated by over £25 million per annum.

Ofgem's decision

3.45. From GDN sales up to 2006-07 NGG provided a discount to the IDNs on its charges for the emergency call handling service. This meant that the emergency call handling costs of the IDNs were understated by £1.2 million. We have added this amount to the IDNs' work management costs and then updated the benchmarking analysis. This increases the GDNs' opex allowances by approximately £1 million per annum.

3.46. We have corrected an error in the number of governors for NGN in PB Power's maintenance workbooks. This increases total GDN opex by £0.8 million per annum. There is a £1 million per annum increase for NGN and a £0.2 million per annum decrease for the other GDNs combined.

3.47. We have carried out a further review of our maintenance analysis in light of comments from the GDNs. This has resulted in some costs being reallocated from routine to non-routine maintenance, correction of minor differences between non routine high pressure storage costs removed before regression and those added back after regression, and correction of a difference between high pressure revalidation costs taken out of capex and those added back to opex; all of which have a consequential impact on allowances. We have also included additional costs associated with cathodic protection work which is a new requirement and was not fully reflected in the base year's costs. However, we do not accept that 2006-07 was an atypically low year for maintenance activities in general. The GDNs have highlighted those areas of activity where costs were atypically low but it is reasonable to expect that some areas of costs would also have been atypically high in that year. The overall impact of the changes to our maintenance analysis is to increase our opex assessment by approximately £5 million per annum.

3.48. We do not consider it is appropriate to adjust our approach to determining emergency service opex because of NGN's failure to meet the prescribed level of performance for attending gas escapes within 1 hour. Our forecast is based on the upper quartile level of costs between the 2nd and 3rd lowest cost GDN rather than just being based on NGN's performance. Other GDNs receive a cost forecast that is higher than NGN's 2006-07 costs and to the extent that NGN needs to increase its costs to perform better it would simply receive a lower outperformance benefit for this activity.

Demolition costs

3.49. The majority of gas holder demolitions are likely to be associated with sales and therefore under our approach to disposals the costs would be netted off the sale proceeds. However, we recognise that some holder demolitions may be carried out for safety, operational or environmental reasons and are not associated with a sale of property. We have included £0.1 million per annum per GDN in our opex assessment to cover such costs.

Normalisation

3.50. We have reviewed the treatment of WWU's occupational health and travel costs which were removed from the HR function as part of LECG's normalisation costs. PB Power added these costs back to work management. We consider that any remaining minor differences in treatment of costs across GDNs because of cost allocations or differences in business structure are addressed by the uplift on our disaggregated opex assessment.

xoserve

3.51. We have made adjustments to our forecasts of xoserve costs based on comments regarding the allocation of inefficiencies and users pays costs between GDNs and the NTS, the allocation of costs to opex and capex and inconsistencies in the application of the support service. This increases opex by £3.7 million per annum across the GDNs.

3.52. We consider that our efficiency assumptions for xoserve in updated proposals are still appropriate. We consider that it is appropriate to apply the benchmarks we have established from the GDNs to xoserve. The property benchmark used by LECG was only applied to office space, not depots or sheds, so it is on a like for like basis. The work by Compass for TPCR identified some inefficiencies in the CSC contract which is managed by NGG and includes some services for xoserve. We would expect some of these inefficiencies to apply to xoserve. LECG's analysis focussed on IS and Property Management within xoserve (due to materiality and lack of comparators in other areas) and since these two categories represent just under half of xoserve's costs the efficiencies identified in these activities should not be unachievable for the business as a whole.

Indirect opex

3.53. Our analysis of indirect opex for initial proposals was based on work carried out by LECG. That work was based on benchmarking each of the GDN ownership groups for each of the categories of indirect opex using a mixture of internal benchmarks (i.e. between GDNs) and external benchmarks where there was a suitable external benchmark.

3.54. At updated proposals LECG updated their analysis for 2006-07 actuals. We also revised our approach to one involving only internal benchmarks for all support service activities other than property management, to take account of comments received from the GDNs concerning the appropriateness of the external comparators given the different nature of the businesses. For property management we continued to use external benchmarks for the rental costs of specific properties. Additionally we moved to benchmarking at the second best GDN rather than the upper quartile (between best and second best) where SGN was the lowest cost group because of issues raised about the possibility that marginal costing for SSE support services to SGN might be creating benchmarks that were unachievable by other GDNs.

3.55. We have made three main changes to the indirect opex analysis since updated proposals. These changes affect IS benchmarking, HR benchmarking and insurance cost forecasts.

3.56. We have adjusted the IS benchmarking to remove the double counting of NGG's efficiency assumption for IS support services opex and to address the issue of additional efficiency savings being applied to an area where NGG has already assumed a stretching efficiency target. The overall annual efficiency savings for IS support service costs are now 4 per cent per annum consistent with the NGG's own forecasts. This increases the IS allowance across all GDNs by approximately £2.0 million per annum.

3.57. We have revised the benchmark for HR so that it is based on total HR costs (excluding learning and development and apprentice costs) per full-time equivalent employee. The levels of outsourcing of the HR function affected the benchmarks we had applied in updated proposals. This increases opex by approximately £1.4 million per annum across the GDNs.

3.58. We have revised our approach for forecasting insurance costs in light of the arguments from the GDNs that the market cycle approach is only relevant to insurance premia and not uninsured claims. This change results in a reduction in the allowances for insurance across all GDNs of £0.6 million per annum. We have also made a revision to our benchmarking analysis so that SGN receives an outperformance reward for being the frontier performer on insurance costs, consistent with our approach for other activities. This increases its opex allowance by £0.3 million per annum.

3.59. We also applied some minor corrections to the regulation and property management benchmarks.

3.60. The detailed changes that we have made to our opex analysis have increased our average annual opex assessment for NGG's four GDNs by approximately £12 million per annum compared to over £25 million per annum that NGG considered should be allowed. These changes have increased our average annual opex allowances for the four IDNs by approximately £7 million per annum.

Regional factors

3.61. In both initial proposals and updated proposals our assessment of operating costs took account of regional differences in labour rates. In updated proposals we provided additional regional allowances recognising that it is more expensive to meet the emergency service response requirement in areas of exceptionally low customer density as well as there being higher operating costs in areas with very high population densities. The non-labour regional allowances we proposed were £2.0 million per annum for Wales and West, £1.0 million for Scotland, £1.9 million for London and £1.2 million for Southern.

Respondents' views

3.62. The GDNs for which we had applied a regional adjustment have argued that we have underestimated the additional costs of operating within their areas. WWU has put forward further analysis to support a regional adjustment of £5.2 million per annum for its area. SGN argued that it should receive additional costs of £1.1 to £1.5 million per annum associated with the need for extra emergency service FTEs and a further of £0.4 million per annum associated with additional depots.

3.63. Similarly other GDNs have argued that they also experience additional costs relating to operating in dense or sparse areas. NGN has argued that it suffers from both high and very low-density areas. Using customers per kilometre of network as a measure of sparsity, Northern GDN is the sparsest network. It has the third lowest customers per square kilometre, even though it covers the Newcastle and Leeds/Bradford conurbations. NGG argues that East of England is a low-density area similar to WWU and Scotland and that it should receive a regional allowance of £1 million per annum for East of England equivalent to that given for Scotland.

3.64. Both NGG and SGN have argued that there are higher regional costs associated with working in London than we allowed for in updated proposals.

Ofgem's decision

3.65. We consider that our existing regional allowance of £1 million per annum is appropriate for Scotland. Our allowance is primarily focused on the additional costs of operating the emergency service and is close to the bottom end of the range put forward by SGN for such costs.

3.66. WWU has put forward further analysis to support a regional adjustment of £5.2 million per annum for its area. We do not consider that the updated analysis adequately addresses some of the issues we raised in updated proposals. The analysis assesses the additional costs of running the emergency service relative to an "ideal square" shape but fails to recognise that none of the other territories other than West Midlands approximate to such a shape. It also assumes that all costs associated with areas outside the perfect square are efficiently incurred rather than merely replacing costs that would be incurred if all customers lay within it.

3.67. WWU supports its analysis of 64 additional emergency employees being required to manage customers falling outside an "ideal square" with regression analysis of the number of staff against a composite variable including network length and customer numbers. It argues that this demonstrates that an additional 54 staff members are required based on the difference between their staff numbers and those of the upper quartile performer. This effectively assumes that any additional WWU staff relative to the upper quartile level of staff are associated with operating in a sparse area rather than differences in efficiency. Taking this into consideration, we consider that our regional adjustment for WWU of £2 million per annum is still appropriate.

3.68. The main justification for providing an additional sparsity allowance is associated with the need to provide emergency service cover for all customers within the territory served within the 1-hour standard. We consider that the number of customers per square kilometre is a better (though not ideal) way of determining the difficulty in providing this. We do not consider that either NGN or East of England are major outliers in terms of their customer densities and we are not proposing any adjustment to the opex assessment.

3.69. NGG has presented additional evidence on the size of excavations required in North London relative to other GDNs and has also provided further information on relative labour costs for its workforce in London compared to the rest of the country. By contrast other GDNs have argued that we have overstated the London regional allowances and that our analysis of relative salary levels picks up salary differentials across all sectors including pay for financial services employees in the City of London. On balance we consider that it is appropriate to maintain our existing level of regional costs for both labour and non-labour factors and propose no change for London or Southern GDNs.

Apprentice and training costs

Respondents' views

3.70. The GDNs have submitted a revised model by EU Skills on the requirements for apprentices over the next price control period and the associated level of costs. This suggests an increase in apprentice costs from the £68 million we allowed in updated proposals to £98 million but down from the initial £217 million which EU Skills had sought in addition to the GDNs' initial BPQ submissions.

3.71. A number of non-GDN responses welcomed our proposals for apprentice and training allowances although some questioned whether our proposals were sufficient.

3.72. NGG argued that it was inappropriate to allocate the apprentice and training allowance based on FTEs and that we should instead apportion apprentice needs on the basis of total resources required. WWU suggested that the allocation should be based on differences in age profiles.

Ofgem's decision

3.73. We consider that the revised EU Skills modelling represents a more realistic forecast in that it reduces the apprentice drop out rate to 5 per cent, allows for some productive work for apprentices and considers alternative routes for bringing on board skilled staff. However, we still consider there are weaknesses in the analysis. The model assumes no productive work until years three or four of the apprenticeships and assumes a flat requirement for skilled staff, not allowing for any efficiencies over the price control period. Taking these factors into consideration we consider that our updated proposals allowances are reasonable. We have looked at an alternative approach for allocating the allowances based on forecast costs for the emergency service, repairs and maintenance but this does not result in a significantly different allocation. We do not consider it is practical to allocate the allowances based on age profiles so we have retained our existing approach.

3.74. We have included an additional £2.5 million per annum across all GDNs. £0.8m of this is associated with graduate training and included in the additional allowance for apprentice/skills shortage, the remaining £1.7m is safety-related training that has been added back to the HR allowances after benchmarking. We have reviewed the information provided by all GDNs on historical and forecasts levels of such training costs. There are significant differences in levels of these costs between NGG and the IDNs which suggests that the IDNs have included some of these costs within their direct opex activities and therefore that they are already partially accounted for in the benchmarks for those areas.

Capex opex trade-off

Respondents' views

3.75. NGG has argued that our approach to the opex assessment has failed to recognise the interaction between operating costs and capital investment. It argues that its planning processes consider whole life cycle costs and it makes decisions on investment based on medium-term benefits, which may result in higher opex in the short-term. It considers that Ofgem's approach has resulted in insufficient allowances for NGG based on benchmarks from businesses that have invested significantly higher levels of capex, which enable additional opex savings.

3.76. SGN said that they do not consider opex-capex trade-offs to be material in the context of a five year price control review.

Ofgem's decision

3.77. In updated proposals we acknowledged that there was some merit in NGG's capex-opex trade-off arguments but noted that there was difficulty in quantifying the interactions and challenged NGG to provide further evidence to support their case.

3.78. We have reviewed the arguments put forward by NGG and consider that there is sufficient evidence to support an adjustment being applied to our opex assessment for its GDNs. We have adopted a similar approach to that used in DPCR4 to quantify the trade-off. We have carried out a regression of opex plus an eleven year average of governor, other operational and non-operational capex using the same CSV as the top down opex analysis. We have excluded LTS, connections and mains reinforcement capex, as differences for these activities are largely driven by demand growth, and repex, because differences between GDNs largely reflect differences in the diameter mix of mains replacement work. We have then compared the level of efficiency and benchmark costs based on an average of this "totex" regression and a pure opex regression with the results of an opex regression on its own. This gives additional costs of £6.2 million per annum for NGG's GDNs, which we have added to our opex assessment, compared to the range of £14-16 million that NGG proposed. Further details are set out in appendix 5.

Real price effects (RPEs)

Respondents' views

3.79. In both initial proposals and updated proposals we assessed operating cost forecasts on the basis that direct labour, contract labour and material prices would increase in real terms by 1.0 per cent per annum, 2.0 per cent annum and 1.0 per cent per annum respectively. The GDNs have all put forward strong arguments for higher real prices effects. The GDNs have argued that real prices for contract labour would increase by up to 4 per cent nationally. Both NGG and SGN have argued that there should be a further premium of up to 1.5 per cent in London. The GDNs have suggested that our assumption of 1 per cent real growth in earnings for direct labour is insufficient given skilled labour shortages. They suggest that our assumption for increases in material costs is unrealistic given recent rises in costs for both PE and steel pipes.

Ofgem's decision

3.80. We acknowledge that there is evidence in the short-term to support a higher level of real input price inflation for contract labour. In particular, applying the methodology we supported at initial proposals, using the historical Baxter index and tender price information, now points to real contract price inflation of around 3 per cent. The recent work by Experian commissioned by the Competition Commission (CC) as part of the BAA review suggests high input price inflation over the next 3 years followed by a decline towards the end of the period.

3.81. On this basis we propose to allow for real growth in contract labour prices of 3 per cent for the 2006-07 to 2009-10 and 2 per cent for the next 3 years giving an average of 2.5 per cent in determining our cost assessment.

3.82. Inevitably some of the pressures driving the increases in contract labour will also feed through into direct labour. On this basis we propose real growth in direct labour earnings of 1.5 per cent per cent, which is derived by increasing the real price effect to 2 per cent for 2006-07 to 2009-10 and 1 per cent for the next 3 years.

3.83. In addition, since updated proposals a strong case has been made by the GDNs that the real price inflation assumption for materials was significantly understated. PE pipe is a significant element of GDN material costs, and the cost of PE pipe has increased significantly as its manufacture involves the use of oil as a raw material and the manufacturing process is energy intensive. The production of steel pipes is also energy intensive. We propose a real price effect of 3 per cent for materials based on the revised evidence. Further details are set out in appendix 6.

Assumption for ongoing productivity

Respondents' views

3.84. The GDNs have argued against our ongoing efficiency assumption of 2.5 per cent per annum for operating costs. They criticised the work we had commissioned from Reckon LLP and stated that we should place greater reliance on the work of their consultants, First Economics, which suggested that productivity savings net of real input price growth would show real cost increases of between 0 per cent and 0.5 per cent per annum. They also argued that in basing our 2.5 per cent productivity assumption on a 1.1 per cent comparative competition effect and a 1.4 per cent from Reckon LLP’s labour productivity work we had double counted the benefits of comparative competition, since we had already derived a 1.2 per cent per annum benefit from our benchmarking analysis. They argued that since the 2.5 per cent per annum productivity improvements are based on labour productivity, we should only apply this to labour costs within GDNs' opex which amounts to approximately 70 per cent of their total opex.

Ofgem's decision

3.85. We have commissioned further work from Reckon LLP, which suggests that its analysis is still appropriate. Its methodology is designed to overcome issues of high or low capital growth in comparators overstating or understating the scope for labour productivity improvements in gas distribution. We still consider that 2.5 per cent per annum efficiency assumption is appropriate based on the middle of Reckon LLP's range. This has the impact of reducing average X by 0.9 per cent per annum.

3.86. In deciding the proportion of opex to which the labour productivity assumption should be applied, we need to consider the whole value chain. For example in addition to direct and contract labour many other elements of opex will also have a labour component and labour productivities associated with them. It is reasonable to expect there to be efficiencies even for capital elements of costs. Further details are set out in appendix 6.

Pensions

Approach at updated proposals

3.87. Our approach to making allowances for ongoing pension costs has not changed since initial proposals. Cash pension contributions relating to service within the price control period have been normalised at 2006-07 levels and included in the benchmarking of operating costs. Additional costs have then been included to reflect the difference in contribution rates between the GDNs' latest actuarially recommended contribution rate and the rate included in the normalised benchmark. This approach is consistent with the pension principles Ofgem has followed since 2003[2].

3.88. Should actual pension costs differ from allowed pension costs due to changes in the ex ante assumptions underlying the pension allowance, then these are allowed through an ex post adjustment within the subsequent price control. Should a GDN choose to fund more or less than the amount required by an actuarial valuation, a similar adjustment is made, subject to ensuring that consumers are not disadvantaged by the additional or reduced level of contributions. For 2007-08 to 2012-13 the impact of the ex post adjustment is limited to changes in actuarial valuations only, i.e.:

(Actual DB cash contribution) – (Actual DB pensionable salary * allowed contribution rate)

[2] The pension principles were set out in Developing Monopoly Price Controls, Initial Conclusions, June 2003, and then applied within DPCR4 and TPCR.

3.89. This will result in efficiency savings being retained by the GDNs within the GDPCR review period, and inefficiencies being borne by the GDNs. The relevant allowed contribution rates are set out in Table 3.3 below.

Table 3.2 - GDN allowed contribution rates, 2008-13

	Future accrual contribution rate
East of England	31.8%
London	31.8%
North West	31.8%
West Midlands	31.8%
Northern	35.5%
Scotland	37.3%
Southern	37.3%
Wales & West	39.3%

3.90. We also included the costs of payments over a 10 year period to close the pension deficits in each GDN's pension fund. We indicated in initial proposals that we intended in due course to carry out a cross-networks review of the risk of stranded surpluses arising in the future. Finally we included a pass-through term for payments to the NTS representing the cost of each GDN's former employees.

Respondents' views

3.91. No specific questions were asked on pensions in the updated proposals. Respondents to previous consultation documents had broadly supported our approach on pensions although some respondents argued that we should take a tougher approach in the light of such historically high contribution rates.

Ofgem's decision

3.92. We continue to consider that the approach set out above is appropriate for this price control.

Carbon Monoxide

3.93. In October, we held a workshop to clarify our aims and objectives with regards to equipping first call operatives (FCOs) with carbon monoxide in air equipment for use when attending gas emergencies. The workshop was attended by all major parties that responded to carbon monoxide issues in our initial proposals. All GDNs were represented, along with the HSE, GMB, British Gas, CORGI, a number of IGTs and CO-Gas Safety. The focus of the workshop was to clarify the key roles and responsibilities of the GDNs when acting as an FCO, whether there was a benefit in FCOs carrying CO in air measuring equipment and, with regards to raising awareness of the dangers of carbon monoxide, what options were available for improving public awareness of CO by the FCOs and GDNs.

Respondents' views

3.94. The GDNs identified a number of areas where they considered they are currently improving awareness of CO and gave examples of work such as initiatives with Help the Aged. Although the GDNs were supportive in principle of reducing carbon monoxide incidents, they felt there were limitations as to what could be achieved by a proactive approach by the GDNs and were concerned over the use of CO in air measuring equipment by FCOs. The GDNs indicated that the use of CO in air measuring equipment would increase the amount of time they were required to be on site and hence the cost of the emergency service and that the use of atmosphere monitoring could be open to misinterpretation and unintended results. They also indicated that, on natural gas emergencies they are responsible for evacuating members of the public, making safe, repairing any leaks on their network and then allowing consumers back into properties. With carbon monoxide emergencies they considered their responsibilities were solely to make safe by isolating the supply at the emergency control valve (ECV). This could still result in the GDN evacuating properties but with another party being required to attend site to identify and repair or replace any faulty appliances.

3.95. British Gas presented a number of initiatives that were currently being worked on by COCAA (Carbon monoxide Consumer Awareness Alliance), of which at present two of the four GDNs, are members. This group ss proactively looking into a number of ways of eradicating CO deaths and injuries.

Ofgem's decision

3.96. Given the views from the workshop, and the other responses to updated proposals, we consider that further assessment and discussion is needed before we can decide on the most appropriate way forward.

3.97. Ofgem will set up a working group with specific terms of reference and timeframes to encourage the GDNs, GTs and other stakeholders to take ownership of the issues and further consider whether changes to operating practices and procedures are appropriate for FCOs attending a gas emergency. This could include any other CO initiatives that may be of overall benefit. The working group would be expected to make specific proposals with robust cost, benefit and consequential analysis that could then if appropriate be reviewed by Ofgem. The detailed terms of reference will be decided by the working group at its first meeting but will broadly be:

- to consider whether changes to operating practices and procedures are appropriate for FCOs while attending a gas emergency; and
- to minimise carbon monoxide deaths and injuries and maximising consumer awareness of the dangers of carbon monoxide.

3.98. The working group will need to take into account other initiatives being taken forward on CO and, in particular, to work directly with the CO Consumer Awareness Alliance. Ofgem would expect all GDNs to be active participants of this group.

3.99. We expect the working group to provide recommendations (including an assessment of the costs and benefits) within one year of its first meeting. In the light of the group's findings, Ofgem would expect to modify the GDN licences, in particular, where further clarity is required on what is expected from GDNs and if, in fulfilling, these requirements GDNS could reasonably be expected to incur additional costs.

4. Capital and replacement expenditure analysis

Chapter Summary

This chapter sets out our final proposals for capital and replacement expenditure taking into account responses received to updated proposals, ongoing analysis, and further information received from the GDNs.

Introduction

4.1. In October 2006, we received responses to our BPQs from each of the GDNs setting out their historical capex and repex for 2002-03 to 2005-06 and forecast expenditure for 2006-07 to 2012-13. We appointed PB Power to support our assessment of the forecast capex and repex.

4.2. Over the period October 2006 to March 2007 PB Power carried out a detailed assessment of each GDN's capex and repex requirements. It reviewed the GDNs' BPQ submissions and raised supplementary questions to gain a better understanding of the GDNs' data and, where appropriate, gather additional information to support the cost assessment.

4.3. PB Power, together with Ofgem staff, visited each GDN in order to discuss their BPQ submissions, ask follow-up questions and to challenge and improve their understanding of the GDNs' forecast assumptions.

4.4. PB Power's work included:

- a high-level assessment of policies, procedures and forecasting processes associated with capex and repex;
- a review of GDNs' forecast costs to understand whether they were based on appropriate assumptions including the justification for their workload forecasts, assumptions for real price increases and productivity;
- an assessment of GDNs' efficiency for particular capex and repex activities by benchmarking costs across GDNs; and
- bottom-up analysis to consider the appropriate costs for particular activities based on information submitted by the GDNs and its own engineering experience.

4.5. We summarised this work in our March consultation document and consulted on both the methodology and the results.

4.6. In initial proposals we set out our capex and repex forecasts for each GDN based on PB Power's assessment together with further work by ourselves to consider the GDNs' BPQ responses, their initial views on the PB Power reports and our own assumptions for regional factors, productivity and real input price increases.

4.7. In June we received an updated submission from each of the GDNs setting out their actual capex and repex for 2006-07. In July we received updated forecasts from each of the GDNs for 2008-09 to 2012-13. We also carried out additional costs visits to each of the GDNs to discuss their latest LTS capex forecasts. Our updated proposals were based on analysis of this additional information and took account of comments we received from the industry in response to initial proposals.

4.8. Our final proposals for capex and repex take into account further comments from the industry and analysis we have carried out.

4.9. The following sections explain our overall approach for assessing the expenditure requirements for each of the capex and repex activities, the main issues that were raised in response to updated proposals, the key changes we have made to our analysis and our final proposals for capex and repex.

Capex analysis

4.10. A summary of our final proposals compared to the GDNs' own forecasts and our updated proposals assessment is presented in Tables 4.1 and 4.2 below. A more detailed breakdown for each year by GDN is set out in appendix 8. The numbers in Table 4.1 are presented prior to the application of the Information Quality Incentive (IQI). Table 4.2 presents our assessment following application of the IQI.

Table 4.1 – Final proposals for capex (pre IQI) (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU	
GDN normalised average annual net capex 2008-09 to 2012-13	**East of England**	**London**	**North West**	**West Midlands**	**Northern**	**Scotland**	**Southern**	**Wales & West**	**Total GDN**
LTS & Storage	9.7	26.8	14.5	1.9	15.3	15.1	32.4	29.0	144.8
Connections	10.0	5.4	4.4	3.6	9.2	5.4	8.0	8.9	54.8
Mains Reinforcement	3.1	2.6	2.6	2.4	5.0	6.9	14.5	8.4	45.5
Governors	0.6	2.0	3.3	0.7	1.8	3.4	9.8	1.4	22.9
Other Operational	1.4	1.1	1.2	1.2	5.5	4.5	5.0	6.5	26.4
Non Operational	17.4	9.5	12.0	8.6	15.6	8.9	14.3	15.4	101.8
Total Net Capex	**42.4**	**47.5**	**38.0**	**18.3**	**52.3**	**44.3**	**83.9**	**69.5**	**396.2**
Ofgem updated proposal allowances									
LTS & Storage	7.8	23.1	5.6	1.9	12.6	10.9	27.8	14.7	104.4
Connections	6.8	4.4	3.8	3.1	6.4	4.7	7.1	7.0	43.3
Mains Reinforcement	2.4	1.4	1.6	1.7	3.0	4.8	8.8	4.6	28.3
Governors	0.6	1.9	3.2	0.7	1.7	3.2	9.0	1.3	21.5
Other Operational	1.4	1.1	1.2	1.1	4.3	4.1	4.5	6.0	23.8
Non Operational	17.4	9.6	12.0	8.6	14.1	8.1	13.7	14.4	97.8
Total Net Capex	**36.5**	**41.4**	**27.3**	**17.1**	**42.1**	**35.9**	**70.9**	**48.0**	**319.2**
Ofgem final proposal allowances									
LTS & Storage	8.2	23.6	5.8	2.0	13.2	11.4	31.0	20.8	115.9
Connections	7.0	4.5	3.8	3.2	6.5	4.9	7.3	7.1	44.3
Mains Reinforcement	2.7	1.5	1.7	1.9	3.3	5.2	9.9	5.0	31.2
Governors	0.6	2.0	3.4	0.7	1.8	3.3	9.3	1.4	22.5
Other Operational	1.5	1.1	1.2	1.2	4.6	4.3	4.7	6.4	25.2
Non Operational	17.6	9.8	12.3	8.9	14.4	8.4	13.9	14.7	100.1
Total Net Capex	**37.6**	**42.6**	**28.2**	**17.8**	**43.7**	**37.5**	**76.3**	**55.5**	**339.1**
% change to UP allowances	3.0%	2.8%	3.3%	4.0%	3.8%	4.4%	7.6%	15.6%	6.2%

* Note: A number of small errors to the GDNs normalised net capex submissions for LTS and Non Operational capex have been corrected post updated proposals.

Table 4.2 – Final proposals for capex (post IQI) (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU	
Average annual net capex 2008-09 to 2012-13	East of England	London	North West	West Midlands	Northern	Scotland	Southern	Wales & West	Total GDN
GDN Normalised Net Capex	42.4	47.5	38.0	18.3	52.3	44.3	83.9	69.5	396.2
Ofgem Final Proposals Allowances (pre IQI)	37.6	42.6	28.2	17.8	43.7	37.5	76.3	55.5	339.1
Ofgem Final Proposals Allowances (post IQI)	38.1	42.9	28.6	18.1	44.4	38.4	77.9	56.7	345.2
% change to UP allowances (post IQI)	2.4%	2.4%	2.6%	3.3%	3.0%	3.6%	6.8%	14.4%	5.5%

LTS & storage capex

4.11. Our proposals for LTS capex have been built up from our consultants' recommendations for workload and costs for each activity. Our consultants reviewed all major projects submitted by the GDNs in the price control period to derive a set of benchmark unit costs for LTS pipe-lines.

4.12. The derived unit costs were reviewed against PB Power’s own unit cost estimates that were developed as part of the one year price control and updated following the GDN’s latest BPQ submissions and further desktop assessments of major pipe-line projects.

4.13. PB Power reviewed both the need for an LTS project, based on available capacity and pressures from the NTS together with a review of the demand and growth assumptions used by the GDNs in their plans, and also the cost of alternative options for the GDN to meet its capacity requirements.

4.14. Where our consultants considered that capacity needs had been overstated they proposed a number of deferrals to projects, delaying construction for some projects within the price control period and deferring other projects into the next price control period. The following section details further the major projects and proposed changes to their costs and timing.

Respondents' views

4.15. The GDNs have raised a range of concerns with our updated proposals for LTS capex.

4.16. NGG is concerned that we have been inconsistent in applying PB Power’s findings in a number of areas. For example, although PB Power considered that a storage project was needed for North-West GDN and would provide additional benefits to other GDNs and provide flexibility against the uncertain backdrop of interruption reform, we have deferred this investment to 2013-14. NGG considers that the Sutton on the Hill to Ashley Hay project in East of England can only be deferred if this project is allowed.

4.17. NGG notes that Ofgem has deferred the Peters Green to South Mimms project on the basis that additional NTS flex could be made available. NGG highlights that it has recently received lower source pressures to this offtake, which suggests that additional flex is unlikely to be available.

4.18. WWU has noted that since it has not been given additional offtake pressure in South Wales as part of the Offtake Capacity Statements (OCS) process, it is unable to defer the Bancyfelin to Lampeter pipe-line project.

4.19. In light of the latest information on the availability of NTS exit capacity that was received as part of the OCS process, SGN has increased its overall capex forecast. It has reduced its forecast for Scotland GDN by £1 million based on two pipe-line projects being combined, one project being re-costed and the net effect of a number of projects being rephased. SGN considers that the Bathgate to Armadale project in central Scotland has to be completed by 2011-12 as NGG Transmission has not committed to provide any additional flexibility capacity to Scotland for that year.

4.20. In contrast, SGN has increased its forecast capex for Southern GDN by £8 million. SGN acknowledge that the Stoneham Lane and Farningham Phase 2 projects can be deferred from 2009-10 to 2011-12. However, it argues that this results in additional costs associated with work to upgrade the offtakes at Braishfield 'A' and Farningham to remove capacity and metering constraints. It also argues that there are extra costs associated with the purchase of sites, owner/occupier payments and the need to rework environmental studies. SGN argues that we have not taken into account its latest tender price information for the Barton Stacey and Stoneham Lane projects.

4.21. NGN accepts our proposal that the Eggborough pipe-line will be included subject to an ARCA being signed. It suggests that an ex-post adjustment should be made to allow the efficient costs of the project if an ARCA is signed after February 2008. NGN notes that the timing of the Keighley to Calder Valley project is sensitive to demand growth. It acknowledges that it may be possible to defer this project to 2013-14 as we have proposed but considers that there should be an ex-post adjustment to allow the efficient costs in 2012-13 if it proves necessary to bring the project forward.

Ofgem's decision

4.22. We have corrected an error in PB Power's LTS workbooks which affected our forecast capex for SGN. The correction has increased our LTS capex assessment for SGN by £6.2 million.

4.23. In updated proposals we proposed to defer a number of large LTS pipe-line projects either within or out of the next price control period on the basis that the additional flexibility requirements could be met from the NTS as there was no evidence of NTS flex constraints. We explained that we would revisit this issue based on revised information on the availability of NTS exit capacity, which would be available in early October.

4.24. Based on the updated information it is clear that the Bancyfelin to Lampeter (£28 million) project for WWU needs to be carried out in the next price control period due to insufficient pressures being obtained from the NTS. We have therefore allowed the costs of this project.

4.25. The OCS returns suggest that there are no significant capacity constraints in other areas up to 2010-11 although there is still significant uncertainty beyond this. As such we consider that it is still appropriate to defer the following pipe-line projects for NGG, NGN and SGN as set out in updated proposals:

- Sutton on the Hill to Ashley Hay (East of England GDN) from 2012-13 to 2013-14;
- Peters Green to South Mimms (London GDN) from 2012-13 to 2013-14;
- A storage project (North West GDN) deferred into the next price control period;
- Keighley to Calder Valley (Northern GDN) from 2012-13 to 2013-14;
- Bathgate to Armadale (Scotland GDN) from 2012-13 to 2013-14; and
- Barton Stacey to Stoneham Lane (Southern GDN) from 2009-10 to 2011-12.

4.26. In addition SGN has shown that the Farningham Phase 2 project can be deferred from 2009-10 to 2011-12. We do not accept SGN's arguments that the Bathgate to Armadale project needs to be done earlier because of a lack of commitment to higher levels of flex being provided by NGG NTS from 2011-12 onwards. NGG NTS has not yet carried out full analysis of flex availability for this period.

4.27. We consider that it is appropriate to allow additional capex for upgrading the Braishfield and Farningham offtakes to enable the deferral of the pipe-line projects in Southern GDN. However, we do not consider it is appropriate to allow extra costs associated with the purchase of sites, owner/occupier payments and the need to rework environmental studies. These costs could have been avoided if SGN had originally decided to defer the work.

4.28. Our consultant, PB Power, reviewed the latest tender price information for Southern's pipe-line projects. However, it considered that the information that was presented at an earlier stage as part of SGN investment board approval process was more robust. It was also consistent with PB Power's desktop forecasts. By contrast the tender price information was from an early stage in the tender process with scope for further reductions in costs as negotiations were completed.

4.29. NGG has presented updated tender price information for the Harefield to Southall project in its London GDN. We have incorporated this change in our latest capex recommendations.

4.30. The net effect of these changes is that overall LTS capex assessment has increased by £57.6 million (or 11 per cent) since updated proposals.

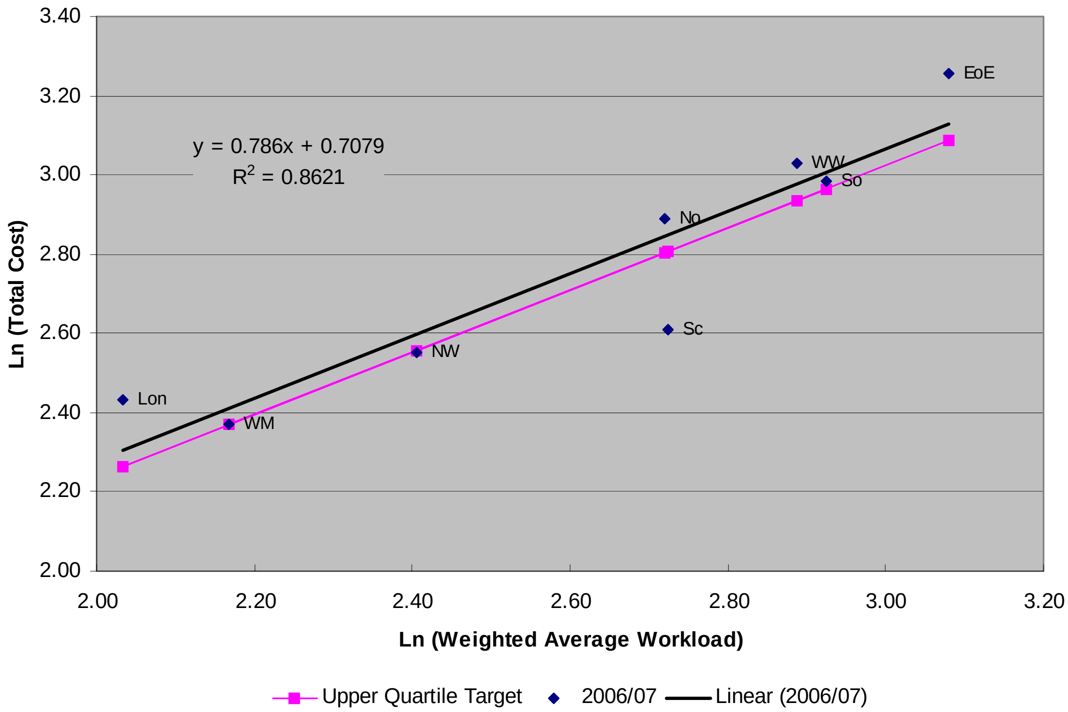
4.31. WWU and NGN have included LTS projects associated with the connection of Uskmouth and Eggborough power stations respectively in their capex forecasts. We have included costs of £8.2 million for Uskmouth power station and £22.5 million for Eggborough power station in our LTS capex forecasts for WWU and NGN in the anticipation that an ARCA will be signed before the final consultation in February 2007 on the revised licence conditions to implement the price control. If this is not the case we will remove these costs from our price control allowances. If an ARCA is signed after this time, we will add back our ex-ante forecast cost for the relevant project and revise the relevant GDN’s price control allowance accordingly.

4.32. The timing of the NGN reinforcement pipe-line for Keighley to Calder Valley is very sensitive to demand forecasts. We consider that this project can be deferred to 2013-14 based the current demand forecasts. In the event that this pipe-line has to be commissioned in 2012-13, we would look to give the project the same treatment as if it had been brought forwards within a price control period.

Approach to connections capex analysis

4.33. Our approach to reviewing Connections capex has been to use regression analysis, as discussed in chapter 3, based on normalised 2006-07 gross connections expenditure with a weighted average connections workload as the costs driver. The results of the regression are presented in figure 4.1.

Figure 4.1 – Regression of 2006-07 Connections Gross Capex against weighted average workload (2005-06 prices)



Respondents' views

4.34. The GDNs have raised a range of concerns with our updated proposals for connections capex.

4.35. Some GDNs have argued that there are issues with the weightings in the connections regression and that we should review this. NGN considers that our adjustment to the average length of mains laid per service for connections is inappropriate. It notes that its historical length of mains per service has always been higher than average and reflects regional differences.

Ofgem's decision

4.36. There is currently a difference in connections charging methodologies between NGG and the IDNs based on a difference in legal interpretation. NGG charges non-domestic consumers for the final connection to its networks whereas the IDNs provide a Final Connection Allowance (FCA) for these costs, which results in a higher level of net capex.

4.37. Following further discussions with the GDNs and we have decided to proceed on the basis that GDNs will charge for final connections and we have updated our connections capex forecasts accordingly to reflect the assumption that no FCA is applied. We have reduced the percentage of net to gross capex for all GDNs where an FCA had previously been applied. GDNs will now be expected to recover this revenue by charges directly to customers as an excluded service.

4.38. We have removed our adjustment to NGN and WWU's mains workload associated with connections. Their historical data shows that their average length of mains per connection is higher than the historical average across the GDNs.

4.39. We do not consider that it is appropriate to change the weightings for the workload driver in the connections analysis. We consider that the 2005-06 unit costs we have used to weight the different components of connections work are more reflective of differences in costs and we have cross checked these against unit costs for similar mains replacement work.

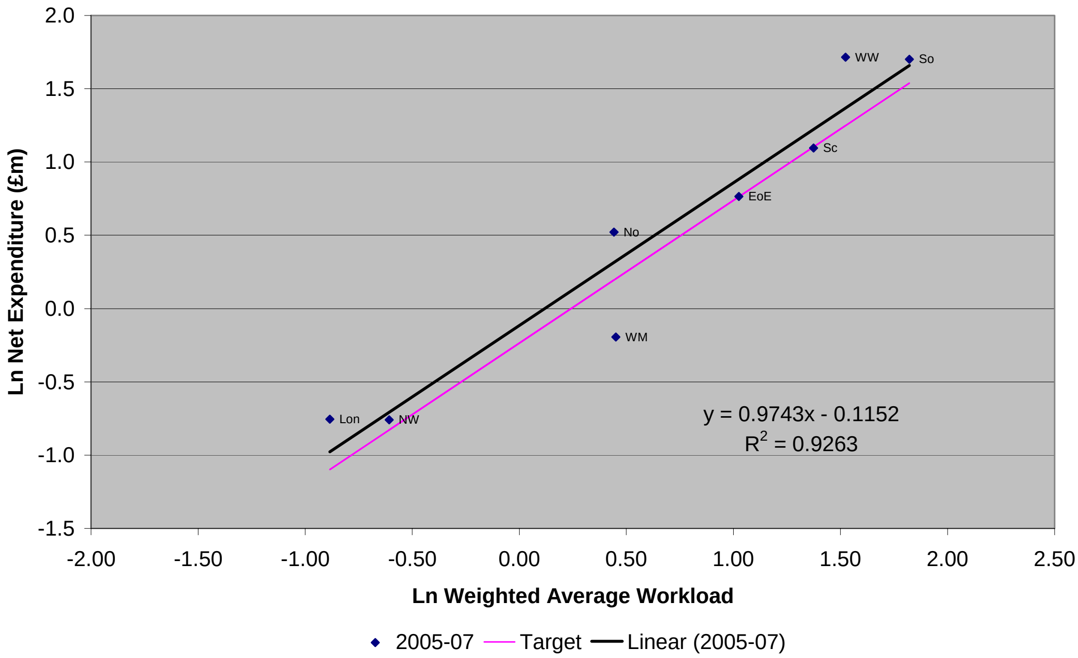
4.40. The net effect of the changes highlighted above results in an increase of our connections net capex forecast of £4.8 million (or 2.2 per cent) since updated proposals.

Mains reinforcement

4.41. Our approach to reviewing mains reinforcement capex has been to use regression analysis, based on normalised 2005-07 gross mains reinforcement expenditure with a weighted average reinforcement workload as the cost driver. The results of the regression are presented in figure 4.2.

4.42. Since initial proposals the mains reinforcement category was revised to include both general and specific reinforcement costs and workloads. General and specific reinforcement activities are similar in terms of planning assumptions and construction techniques employed, therefore these activities have been combined in the regression analysis. The workload and costs associated with specific reinforcement were originally captured within the Connections analysis. Hence some of the costs previously analysed within the connections work area are now reported under mains reinforcement.

Figure 4.2 – Regression of 2005-07 mains reinforcement capex against weighted average workload (2005-06 prices)



Respondents' views

4.43. A number of GDNs have noted that there are low levels of mains reinforcement workload, which means that unit costs are volatile. They have also argued that there are atypical costs associated with large projects in 2006-07. The GDNs have argued that we should base our analysis on two year's worth of data removing any atypical costs.

4.44. In addition SGN has argued that our disallowance of related party margins for the base year has incorrectly been rolled forwards to other years when they have a higher workload. It notes that direct labour or third-party contractors will largely carry out its additional mains reinforcement work.

4.45. A number of GDNs have also stated that the productivity assumptions applied to mains reinforcement are unrealistic given the relatively small workload.

Ofgem's decision

4.46. We acknowledge the GDNs comments that there is a relatively small annual workload for mains reinforcement and some volatility in unit costs. We have now re-run the regression to take into account the costs and workload for both 2005-06 and 2006-07 removing atypical work. We have also sense checked the resulting unit costs against replacement unit costs. This results in an increase in mains reinforcement capex of £14.4 million (10 per cent) across the price control period.

4.47. We have looked in further detail at our productivity assumption for mains reinforcement considering our consultant's recommendations along with the GDNs' proposals. We consider there is less scope for efficiency savings in mains reinforcement than mains replacement given the significantly smaller workload programme and that the workload comprises a number of small, geographically spread projects. As such we have set the ongoing productivity assumption for mains reinforcement at 1.5 per cent.

4.48. We do not consider it is appropriate to make adjustments to SGN’s mains reinforcement to include additional costs associated with SGN outsourcing extra work to third-party contractors or for it to be carried out by internal direct labour rather than SGN Contracting. We removed the related party margins in the base year to be able to benchmark underlying costs across GDNs and establish an efficient base level of costs. We have then rolled this forward to take account of our productivity assumptions and real input price growth.

Non-operational and other operational capex

4.49. Other Operational capex covers two main areas land and buildings and plant and equipment. Plant and equipment covers principally the procurement of aggregate recycling equipment, pressure management equipment, valve remediation work and kiosk refurbishment. Our consultants have reviewed these predominantly on a project specific basis, taking into account a review of the historical levels of expenditure to provide recommendations for future expenditure.

4.50. Non Operational capex includes GDN expenditure on System operations, IS systems, xoserve, tools and vehicles. Our consultants have reviewed the proposed levels of expenditure considering historical expenditure by the GDNs and project specific expenditure for projects above a materiality threshold of £0.5 million.

Respondents' views

4.51. WWU has highlighted concern over the disallowance of expenditure for a replacement to the Gas Transportation Management System (GTMS) and System Operations Managed Services Agreement (SOMSA) exit.

4.52. The principal expenditure in the forecast price control period is for phase one and two of replacement of the GTMS and Supervisory Control & Data Acquisition (SCADA) System and associated non-SCADA systems which manage operational control over all GB Distribution Networks. Phase one includes the costs of a collaborative GDN project to replace the existing systems. Phase two covers the replication of this system in the GDN's own control rooms prior to transfer of operational responsibilities and the replacement of non-SCADA systems. Each GDN is responsible for its own costs in delivering the systems into its own business and is contracting separately with the third party service provider for this part of the project. WWU considers the costs of all elements of this project should be allowed into the price control.

4.53. NGG has raised the issue of potential trade-off between capex and opex.

Ofgem's decision

4.54. With reference to the GTMS project and SOMSA exit we have reviewed the proposals set out by the GDNs. PB Power estimated the costs for replacing the GTMS and SCADA systems and upgrading the non-SCADA systems if SOMSA exit did not take place. These costs were apportioned across the GDNs. Following the principles set out at the time of GDN sales we are not allowing the costs of establishing separate GDN control centres to be passed onto customers. Our cost assessment has been set on the basis that only one set of new systems is required rather than one per GDN owner.

4.55. We have made adjustments to NGG's direct opex allowances to take into account the capex-opex trade offs. These are detailed in chapter 3.

4.56. We have included a total allowance of £11.3 million in 2008-09 across all GDNs for the initial systems set-up costs associated with the Traffic Management Act. These costs have been estimated based on information recently supplied by GDNs. However, as there is some uncertainty as to the efficient level of costs that GDNs should incur these will be the subject of a reopener together with costs associated with obtaining permits and an efficient level of fixed penalty notices.

Repex analysis

4.57. Our final proposals for repex are based on our consultant's assessment, together with further work by ourselves to consider the responses to initial and updated proposals.

4.58. A summary of our repex final proposals compared to the GDNs' own forecasts and our updated proposals assessment is presented in Tables 4.3 and 4.4 below. A more detailed breakdown for each year by GDN is set out in appendix 8. The numbers in Tables 4.3 are presented prior to the application of the Information Quality Incentive (IQI). The matrices in appendix 13 present the mains and service unit costs after the application of the IQI incentive which is discussed further in chapter 6. Table 4.4 presents our forecasts following application of the IQI which applies to total capex excluding LTS and total repex excluding risers.

Table 4.3 – Final proposals for repex (pre IQI) (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU	
GDN normalised annual average net repex 2008-09 to 2012-13	**East of England**	**London**	**North West**	**West Midlands**	**Northern**	**Scotland**	**Southern**	**Wales & West**	**Total GDN**
Mains	69.7	68.4	72.0	49.3	53.4	37.7	104.1	45.0	499.7
Services (excl. Riser costs)	36.2	27.1	30.8	23.2	24.5	19.1	55.9	26.7	243.5
LTS	0.2	0.1	0.1	0.0	7.4	0.1	3.7	8.7	20.3
Total Net Repex	**106.0**	**95.6**	**102.8**	**72.5**	**85.3**	**56.9**	**163.7**	**80.4**	**763.4**
Ofgem updated proposal allowances									
Mains	69.5	64.7	65.2	49.0	45.0	32.3	80.7	38.1	444.5
Services (excl. Riser costs)	28.7	20.2	23.7	17.9	23.8	16.2	45.4	22.6	198.6
LTS	0.1	0.1	0.1	0.0	7.1	0.1	3.5	7.3	18.3
Total Net Repex	**98.3**	**85.0**	**89.0**	**66.9**	**76.0**	**48.5**	**129.6**	**67.9**	**661.4**
Ofgem final proposal allowances									
Mains	71.7	66.5	67.4	50.7	48.7	32.9	86.9	39.0	463.8
Services (excl. Riser costs)	29.4	20.7	24.3	18.4	24.4	16.3	47.2	23.1	203.8
LTS	0.2	0.1	0.1	0.0	7.3	0.1	3.6	8.3	19.6
Total Net Repex	**101.3**	**87.3**	**91.7**	**69.1**	**80.3**	**49.2**	**137.7**	**70.5**	**687.2**
% change to UP allowances	3.0%	2.7%	3.0%	3.3%	5.7%	1.4%	6.3%	3.8%	3.9%

	NGG				NGN	SGN		WWU	
GDN normalised annual average net repex riser costs 2008-09 to 2012-13	**East of England**	**London**	**North West**	**West Midlands**	**Northern**	**Scotland**	**Southern**	**Wales & West**	**Total GDN**
GDN normalised UP Riser costs	2.5	8.4	2.2	1.6	1.3	1.3	5.7	1.0	**24.1**
Ofgem proposed allowances									
Updated Proposal allowances	1.8	6.0	1.6	1.1	1.1	0.9	4.0	0.7	**17.2**
Final Proposal allowances	1.8	6.0	1.6	1.1	1.1	0.9	4.0	0.7	**17.2**
% change to UP allowances	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

* Note: A small error to WWU's normalised net repex submission for LTS repex has been corrected post updated proposals, also NGN resubmitted their repex forecast.

Table 4.4 – Final proposals for repex (post IQI) (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU	
Average annual net repex (excl risers) 2008-09 to 2012-13	**East of England**	**London**	**North West**	**West Midlands**	**Northern**	**Scotland**	**Southern**	**Wales & West**	**Total GDN**
GDN Normalised Net Repex	106.0	95.6	102.8	72.5	85.3	56.9	163.7	80.4	763.4
Ofgem Final Proposals Allowances (pre IQI)	101.3	87.3	91.7	69.1	80.3	49.2	137.7	70.5	687.2
Ofgem Final Proposals Allowances (post IQI)	103.2	89.0	93.4	70.4	82.1	51.0	142.7	73.0	704.8
% change to UP allowances (post IQI)	2.1%	1.9%	2.2%	2.4%	4.5%	0.3%	5.1%	2.6%	2.9%

4.59. Our repex proposals have taken into account our consultant's recommendations for workload and unit costs. They incorporate the mains workloads agreed with the HSE for the mains replacement programme to remove over thirty years all iron mains within 30 metres of a property.

4.60. We have applied three main types of adjustments to GDNs' forecast repex:

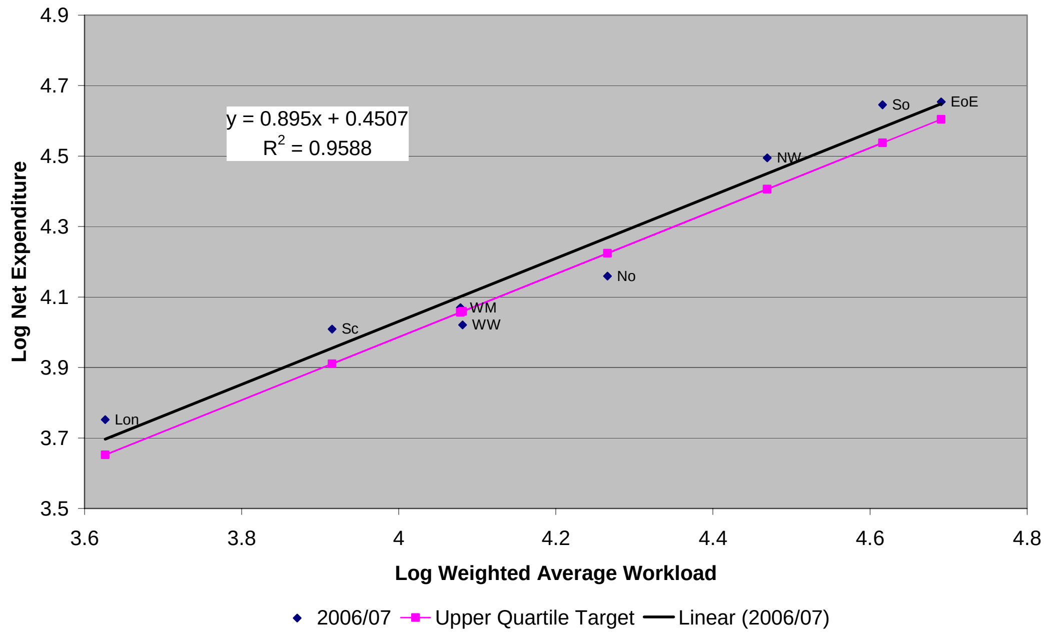
- changes to the GDN forecast workloads for services and non iron mains based on comparisons with historical data and justification for the work;
- changes to the workload mix for mains installed and the ratio of mains abandoned to mains installed; and
- adjustments to unit costs based on regression analysis and our assumptions for regional labour rates, other regional issues, real price effects and ongoing efficiency.

4.61. We have disallowed 62 kilometres (20 per cent) of Southern's condition mains replacement. This is additional work proposed by SGN following a review of their unprotected steel mains policy and a comparison between Scotland and Southern GDN. We do not consider this additional work is justified as no similar policy is being adopted by other GDNs and no persuasive case has been made that circumstances in the Southern GDN are materially different.

4.62. We have made adjustments to the diameter mix of mains to be laid taking into account each GDN's historical workload and remaining iron mains. We have made adjustments to their mix of service relays and service transfers to bring them into line with historical trends based on a comparison across the GDNs.

4.63. Our proposals for mains and service repex have been informed by regression analysis of 2006-07 normalised repex with weighted average replacement workload as the cost driver. The weightings are based on 2008-09 unit costs for different diameters of mains which takes into account the mains and services workload mix for each GDN. The results of the regression analysis are presented in figure 4.3.

Figure 4.3 – Regression of 2006-07 Mains and Service Net Repex against weighted average workload (2005-06 prices)



Respondents' views

Mains and services replacement

4.64. The GDNs have raised a range of concerns with our updated proposals repex analysis and forecasts.

4.65. NGG considers that our downsizing adjustments for repex will lead to a number of network failures. NGG has stated that the downsizing adjustment proposed should only be applied to pipes less than 180mm in diameter and that larger diameter mains cannot be replaced with smaller mains as they are typically trunk mains.

4.66. SGN notes that there is still a £212 million gap between our forecasts for mains and services repex. It considers that this is made up of £118 million starting point/regression difference, a £15 million difference relating to our disallowance of its additional steel replacement and a £79 million difference relating to assumptions for real input price growth. SGN argues that its unit costs for 2007-08 are supported by its latest tender price information, which it has shared with us.

4.67. SGN considers that our adjustment to its workload mix for service replacement is inappropriate. It argues that its 70:30 ratio for service transfers to service relays is supported by its historical data. It notes that reversing this adjustment would add around £5 million to Scotland's proposed allowances.

4.68. Both NGN and SGN argued that they have been penalised because we have applied benchmark unit costs for mains installed but used their own ratio for mains installed to mains abandoned. They argue that the two are incompatible. NGN notes that its allowed unit costs in updated proposals are significantly lower than for any other GDN. It suggests it has been penalised for being efficient.

4.69. Following publication of updated proposals NGN provided a revised BPQ return for mains repex. It stated that its latest mains workload figures showed a significantly smaller abandonment ratio to that previously forecast and it considered it would continue to decline. NGN's revised forecast was based on a ratio of mains abandoned to mains installed of 1.06 in 2007-08 against a historical figure of 1.09, which it had reported in its 2006-07 actuals. Its revised repex forecast for 2008-09 to 2012-13 was £11.8 million higher.

4.70. WWU is concerned at the revision to the workload driver for updated proposals, which resulted in a reduction in its repex allowance.

Riser replacement

4.71. The GDNs have provided further information based on their ongoing programme of survey work to assess the overall riser population and determine requirements for riser replacement. They suggest that this information supports their existing forecasts.

Ofgem's decision

4.72. We have made the following changes to our analysis for final proposals.

Corrections

4.73. There was error in the calculations underlying our regional factors for direct labour costs which led to the regional factor being overstated for NGG's London GDN and marginally understated for the other GDNs. This correction has reduced our overall repex forecasts by £3 million (0.1 per cent) across the price control period.

On-going productivity

4.74. One GDN has stated it considers the 2 per cent productivity assumption applied to mains replacement to be excessive. We have reviewed the GDNs BPQ submissions along with our consultant's recommendation and believe the 2 per cent ongoing productivity is achievable. It is at the top end of the range proposed by the GDNs.

Real Price Effects

4.75. We have increased our real input price growth assumption to 2.5 per cent per annum for contract labour, 1.5 per cent per annum for direct labour and 3 per cent per annum for materials as discussed in paragraphs 3.76 to 3.80 and appendix 6.

Revised standard unit costs

4.76. In June and July the GDNs provided actual capex and repex expenditure for 2006-07 and revised forecasts for the period 2008-09 to 2012-13. The original weightings used within the repex analysis for initial proposals were based on the 2005-06 contract prices for different diameters of mains installed and different types of service work. The revised weightings we are now using within the replacement analysis are more reflective of the current and future replacement workload as the GDNs start to replace significantly more large diameter mains.

Abandonment workload

4.77. SGN has clarified that its resubmission of its mains installed workload for Scotland reflected a change to its ratio of mains abandoned to mains installed rather than any change to it workload for mains abandoned. On this basis we have reinstated Scotland's full mains replacement workload and the associated service replacement work.

Ratio of mains installed to mains abandoned

4.78. Several GDNs have argued that there is a weakness in our repex benchmarking as it is based on unit costs for mains installed but in assessing overall repex we had to make an assumption for the ratio of mains installed to mains abandoned. They suggest that this has been applied inconsistently for different GDNs. For example, SGN has argued that we are cherry-picking as we have based their repex on a benchmark level of costs for mains installed but applied its own ratio for mains abandoned to mains installed. It notes that lower levels of costs for mains installed are typically achieved using insertion techniques that result in a smaller abandonment ratio. It suggests that we should either base our analysis on mains abandoned or apply a consistent abandonment ratio for all GDNs.

4.79. We recognise that there was a potential problem with our updated proposals repex forecasts in that we applied a minimum ratio of mains abandoned to mains installed of 1.05 but we applied GDNs' own ratios where they were above this. This results in a mismatch between our unit costs and the abandonment ratios for some GDNs. We have therefore revised our forecasts so that a consistent abandonment ratio of 1.05 is applied for all GDNs. This increases NGN's net repex by £9.5 million across the price control period. It increases Scotland and Southern's repex by £1.4 million and £4.7 million respectively.

Other policy mains replacement work

4.80. In initial and updated proposals our disallowance of 62 kilometres (20 per cent) of Southern's condition mains replacement was spread proportionately across all of Southern's total work workload. SGN has clarified that the increase in its workload for mains above 12'' relates to an increased volume of condition based replacement for large diameter iron mains which it states it has been undertaking in the recent past rather than increased steel work. We have revised our analysis so that the 62 kilometres are removed from the below 12'' workload.

Downsizing

4.81. In its response to initial proposals NGG raised concerns that our proposed downsizing of their diameter mix for mains installed could lead to failures on parts of its networks. In updated proposals we took this additional information into account but also noted that NGG was proposing a significant programme for replacement of medium pressure mains, which enables it to increase pressures offsetting the loss of capacity. We considered that there were similar opportunities for the low-pressure network. Taking this into consideration together with NGG's comments we reduced our downsizing adjustments for all GDNs by 50 per cent.

4.82. NGG welcomes our revised adjustments but claims that they will still result in network failures. They argue that our adjustments should be limited to mains below 180 mm in diameter. The larger mains are typically trunk mains with limited scope for downsizing.

4.83. It is clear in practice from NGG's historical data that it has downsized larger diameter mains. For example, in 2006-07 NGG abandoned 319km of mains with diameters of 8" or above (equivalent to 203mm) across its four GDNs and laid 182km of mains greater than 180mm in diameter. Based on the abandonment ratio of 1.05 this indicates that at least 122km (40 per cent) of the 8" diameter mains and above were replaced with mains less than or equal to 180mm. However, we recognise that there is much more limited scope for downsizing the largest diameter mains so we have revised our approach to only apply adjustments to mains less than or equal to 355mm in diameter.

Workload mix for services transferred and relaid

4.84. We consider it is inappropriate to change to a 50:50 workload mix for Scotland's service transfers and service relays. The historical data up to 2005-06 suggests a 70:30 mix and there is a step change in the level of service relays associated with mains replacement from 2006-07, which suggests a change in how the workload is measured.

Rebalancing of Scotland and Southern unit costs

4.85. We have carried out a further review of our forecast unit costs for the Scotland and Southern GDNs compared to other GDNs. While Scotland and Southern are close to the industry average we consider that Southern’s unit costs from the regression are lower than we would expect while Scotland’s unit costs are higher. Southern carries out approximately a third of its replacement work within the M25 while the remainder is carried out in the South-East and South of England. We would expect Southern’s unit rates to be similar to a weighted average made up of one third of London’s unit costs and two thirds of East of England. We would also expect Scotland’s unit costs to be below the national average.

4.86. We have increased Southern’s unit costs so that they equal the weighted average for London and East of England and reduced Scotland’s unit costs by an equivalent proportion. This increases SGN’s allowances by £7 million over five years.

Riser replacement

4.87. The GDNs have provided information on actual riser expenditure for April to September 2007. For NGG two of its four GDNs were overspent against forecast and two were underspent. NGG stated that although there was currently an underspend this was predominantly due to the fact that the majority of riser work in the two GDNs took place in the winter period and hence the costs had not yet been seen. Overall it stated that the evidence it provided supported its BPQ forecasts. NGN had not forecast any riser expenditure within the current financial year and had not spent anything to date. WWU had forecast £1 million of expenditure within the current year but its expenditure to date is only £157,000, 16 per cent of its annual forecast.

4.88. The surveys of risers and laterals supplying high-rise buildings are continuing, and are anticipated to be completed by the GDNs in 2008. Based on the information collected so far we believe it is difficult to commence immediately a fully scheduled programme of riser renewal, and so in the early years of the formula period there will be more reactive rather than proactive riser replacement. This initial period will allow for collection of data to determine rates of deterioration and allow for a method, if necessary, to prioritise locations for full replacement.

4.89. We have set our forecasts mid-way between the GDN forecasts and PB Power recommendations. There is insufficient evidence to support a significant increase in our forecasts.

Information quality incentive

4.90. In previous price control documents, we outlined our intention to use an information quality incentive (IQI), as used in DPCR4, where it was called a sliding scale incentive, in order to incentivise appropriately accurate forecasting by the GDNs. This incentive allows us to compare the GDNs' forecast against the results of our consultants' and our own analysis, and use the differential between the two figures (the IQI ratio) to determine three things:

- an appropriate level of allowance for capex and repex;
- the incentive rate to be applied to the under/overspend of capex, and;
- a reward for those GDNs that forecast close to our analysis (or a penalty for those where there is wide disagreement).

4.91. The combination of these items ensures that the IQI is incentive compatible, that is, the GDNs' best outcome is for each GDN to forecast what it expects to spend. Further information on the IQI including the IQI matrix is detailed in chapter 6.

4.92. It is not possible to ascertain to what extent the incentive has actually influenced the company's forecast. We note that the companies who had the greatest IQI ratio at initial proposals have revised their forecasts down. In total, we have also revised our view as set out in the capex and repex analysis above. The overall result is that the range of the GDNs' IQI ratios has narrowed.

4.93. We have applied the IQI in the same way as at updated proposals. We have compared total capex and repex and excluded LTS capex because the timing of our assessment of LTS capex (driven by uncertainty over the enduring arrangements for offtake) did not provide time to allow GDNs to rebid. We have compared mains and services repex excluding risers at consistent workloads, on the basis that the mains and services replacement incentive is designed to deal with differences in workload. Finally, we have maintained the same parameters for the IQI matrix as at initial proposals. The IQI mechanism sets allowances 25 per cent of the way between our assessment and the GDNs' forecasts. Additionally, unless there is a very large gap between the two, the GDNs also benefit from additional income. Given the above we do not consider it necessary to apply the 5 per cent uplift to allowances that was included in DPCR4.

Table 4.5 - Application of the IQI to Capex and Repex (2005-06 prices)

	Total 5Yr capex + repex forecast	Total 5Yr capex + repex allowance (pre IQI)	IQI Ratio	Incentive strength	Additional income	Capex allowance (post IQI)	Repex allowance (post IQI)	Total allowance (post IQI)
	£m	£m			£m	£m	£m	£m
East of England	754.8	703.0	107.6	36%	10.9	190.6	524.8	715.4
London	758.1	679.4	107.6	36%	8.9	214.6	474.9	689.5
North West	715.0	607.2	107.6	36%	9.5	143.0	475.0	618.0
West Midlands	462.0	440.2	107.6	36%	7.1	90.6	357.6	448.3
Northern	694.6	625.4	108.8	36%	8.4	221.9	415.8	637.7
Scotland	512.5	438.3	114.4	33%	3.0	192.2	259.7	451.8
Southern	1,266.8	1,090.3	114.4	33%	7.3	389.6	733.6	1,123.3
Wales and West	754.7	633.6	114.0	33%	4.5	283.5	368.5	652.0
Total	**5,918.6**	**5,217.4**			**59.7**	**1,725.9**	**3,609.9**	**5,335.9**

RAV roll-forward

4.94. As part of final proposals for the one-year control we updated the RAV for actual and forecast expenditure for 2002-03 to 2006-07. The RAV roll forwards for 2005-06 and 2006-07 was provisional based on forecast expenditure. We have now updated this analysis to reflect 2005-06 and 2006-07 actual expenditure. The updated results on the treatment of expenditure for the purposes of the RAV roll forward are set out in Table 4.6 below. This is unchanged from updated proposals.

4.95. Related party margins have been removed as part of our accounting adjustment work before the RAV analysis was undertaken.

Table 4.6 - Treatment of capex and non-mains repex for the RAV roll forwards

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
Total	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	1311.7	1311.7
Total Actual	2175.9	2177.5
Overspend	864.2	865.8
% overspend against allowances	66%	66%
Allocation of overspend		
Related party margins	21.6	16.2
DN sales costs	17.7	17.7
Under recovery of connections income	31.1	13.9
Inefficient above allowance (Pot 1)	36.1	25.9
Efficient overspend (Pot 2b)	671.4	707.1
Reopener (Pot 3b)	86.3	85.0
Total overspend	864.2	865.8
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	11.3	11.2
Efficient allowed spend (Pot 3a)	1300.4	1300.5
Total allowance	**1311.7**	**1311.7**

4.96. The overall impact on the GDN RAV of our decisions on the treatment of overspend in 2002-07 and on forward looking allowances for capex and repex is set out in table 4.7 below. Table 4.7a sets out the RAV roll forward from 1 April 2002 to 31 March 2008, while table 4.7b rolls this forward to 31 March 2013.

Table 4.7a – RAV roll forward table, 2002-03 to 2007-08, all GDNs (£m, 2005-06 prices)[3]

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
	£m	£m	£m	£m	£m	£m
Opening value bf from previous price control	10,634.7					
Additions to pre-2002	91.8					
Revised opening value bf	10,726.5	10,909.1	10,995.6	11,058.3	11,232.7	11,465.8
Depreciation	-376.4	-382.1	-385.8	-389.0	-394.7	-401.9
Net capex additions	570.4	467.4	447.7	567.8	631.3	652.4
Disposals	-11.4	1.2	0.8	-4.5	-3.5	0.0
Closing value	10,909.1	10,995.6	11,058.3	11,232.7	11,465.8	11,716.2

[3] Capex additions for 2007-08 are based on the forecast allowances as set out in our one year control final proposals. If GDNs' actual capex is different from this forecast, the 2007-08 closing RAV (and thus the 2008-09 opening RAV) will be affected.

Table 4.7b – RAV roll forward table, 2008-09 to 2012-13, all GDNs (£m, 2005-06 prices)

	2008-09	2009-10	2010-11	2011-12	2012-13
	£m	£m	£m	£m	£m
Opening value brought forward	11,716.2	12,053.2	12,382.6	12,616.9	12,877.1
Depreciation	-409.7	-419.6	-429.5	-437.6	-446.3
Net capex additions	746.7	749.0	663.8	697.7	673.6
Disposals	0.0	0.0	0.0	0.0	0.0
Closing value	12,053.2	12,382.6	12,616.9	12,877.1	13,104.4

RAV additions criteria

4.97. The allowances include a return on RAV and depreciation based on our assessment of the required capex and repex, as adjusted by the IQI. To the extent that GDNs spend more or less than this assessment, the value of the RAV is adjusted accordingly, but they are subject to a fixed incentive rate that varies between 33 and 36 per cent. These rates are broadly equivalent to at least five years' return and depreciation, and so any adjustment to allowed revenue arising from variations in GDNS' actual spend from the assessment will be taken into account in the 2013-18 price control review, unless we have specifically indicated that an adjustment will be made during the price control, as with the items listed below in paragraph 4.101. The exception to this is expenditure on mains and service repex where differences in unit costs are adjusted during the year of spend, but this does not impact the value of the RAV.

4.98. However, given the importance that a number of interested parties put on the value of the RAV, we consider that it will be useful to publish indicative RAV figures on an annual basis using data collected as part of the cost reporting process. The final decision on these figures will be taken as part of the next price control review (in practice the 2012-13 RAV will not be confirmed until the next but one price control review). The criteria for expenditure being eligible for the RAV is set out below.

4.99. We intend that the power of the incentives is sufficiently strong to encourage efficient decision making. Our default starting point therefore is that all capital expenditure will be included in the RAV, with the exception of expenditure which is judged to be demonstrably inefficient or unnecessary, is not related to the transportation business or has been specifically excluded from our assessment on policy grounds.

4.100. It will still be appropriate for us to review the companies' cost data to ensure that their capex has been correctly recorded, is consistent with the criteria applied in making the ex ante assessment of capex requirements (based on the information made available to us during the price control review process) including the policies adopted for capitalising costs and is not demonstrably inefficient or wasteful. The detailed criteria will be set out in the cost reporting regulatory instructions and guidance (RIGs) but the basic rules are as follows:

- Capex is investment in assets whose benefits can be expected to last for some years, such as high-pressure pipelines and lower pressure mains. This includes expenditure on extending or reinforcing the pipe network or adding new connections.

- Repex is expenditure on replacing component mains and services, where the replacement does not lead to an increase in the capacity or extend the life of the network. Only 50 per cent of repex enters the RAV.

- Expenditure is included net of customer contributions with the exception of connections capex relating to new housing or larger non-domestic customers where effective competition has developed. We expect GDNs to make charges at an up-to-date level wherever they are entitled to do so. Specifically in the case of connections we do not expect non-domestic consumers to be provided with a Final Connection Allowance (FCA), as has been the practice with some GDNs.

- For connections to new housing and larger the net connections capex that will be included in the RAV are the costs associated with the ten-metre rule and final connections allowances (for new housing only) excluding any related party margins associated with this work.

- Where capex is provided by a related party or affiliate, any margin charged by that related party or affiliate should be removed. For the avoidance of doubt xoserve is regarded as a related party for these purposes.

- Expenditure that is a result of diseconomies of scale arising from GDN sales is not eligible for inclusion in the RAV. We specifically consider this to include SOMSA exit costs.

4.101. The items for which we have specifically agreed to reopen the price control, subject to the relevant criteria are:

- The costs of compliance with TMA (see paragraph 2.11)
- The costs of LTS projects associated with the connection of Uskmouth and Eggborough power stations (see paragraph 4.31)
- the NGN reinforcement pipeline for Keighley to Calder Valley (see paragraph 4.32)
- Capex required as a result of the first round of interruptions auctions (see paragraph 6.52)

Treatment of property disposals

4.102. The GDNs have legal ownership of a large physical asset base, including property and land. Within updated proposals, we outlined the mechanism by which we intended to adjust the RAV, in respect of assets which were included in the RAV, either at the time of purchase, or at the time of privatisation.

4.103. From time to time, it may be appropriate to dispose of these assets. For example, if gas holders are no longer required, this may release a land site which is no longer required as part of the operational business. We proposed to adjust the RAV to reflect the net disposal proceeds of such assets. However, to incentivise GDNs to dispose of assets, we propose to apply a standard rolling incentive mechanism, where RAV disposals do not impact the allowed return on RAV for five years. After five years, the income-earning RAV will be then adjusted for gross disposal proceeds, net of direct costs of disposal, and net of directly associated remediation costs.

Responses to Updated Proposals

4.104. Two GDNs responded to our comments on property disposals. One GDN argued that assets belonged to GDNs, not to customers, and that no RAV adjustment would be appropriate, unless the asset continued to be operational. One GDN argued that our proposals did not properly reflect the risks and costs incurred by the GDN in disposing of assets, and that the RAV should only be adjusted for the pre-development value of the land.

Ofgem's decision

4.105. We recognise that adjusting the RAV for the post-development value gives customers the benefit of services provided prior to sale, including planning, design and development. If incurred by the GDN, costs of this nature could be included in the direct costs attributed to the disposal, before sharing of the benefit between the GDNs and customers. However, we do not agree that any valuation other than the actual disposal proceeds to a third party, either pre-development or post-development, can be taken as a reliable measure of value. We do not agree that the risks faced by the GDN need to be allowed by additional RAV return, as we consider those risks are limited, given that the GDN continue to earn income on the original RAV value for any portion of the initial investment not realised as disposal proceeds.

4.106. While it is accurate that the assets are legally owned by the GDNs, operational assets are purchased by the GDNs on the understanding that the costs of funding will be funded through the RAV mechanism. Equally, once those assets are disposed of and to the extent that the GDN has had its investment repaid, there should be an equivalent understanding that customers no longer meet the costs of funding those assets. Therefore the RAV needs to be adjusted for all disposals of assets, otherwise customers would be funding assets which have been disposed and where the GDN has received compensation in the form of disposal proceeds.

4.107. We consider that the proposal to adjust the RAV for the gross proceeds, net of all related costs including decontamination costs, with a rolling incentive, provides the correct balance between GDNs and consumers.

5. Quality of service arrangements

Chapter Summary

This chapter sets out our final proposals for the quality of service arrangements, which will take the form of:
- ➔ requirements that are set out in licence conditions;
- ➔ guaranteed standards of performance, as set out in the Gas (Standards of Performance) Regulations; and
- ➔ a published comparison of the GDNs' performance, in the form of a balanced score card.

Our final proposals are broadly unchanged from updated proposals, although we have refined some aspects of the detail of the proposals. This chapter also details our approach to the scope of gas networks.

Introduction

5.1. As price controls provide strong incentives for GDNs to reduce costs there is a risk that they might achieve this by providing a lower level of service to consumers. The outputs and quality of service arrangements provide an important counter balance to this.

5.2. During the GDPCR Ofgem has reviewed the quality of service arrangements. Our process has included consideration of responses to consultation documents, commissioning consumer research,[4] establishing a quality of service working group[5] and publishing draft and final impact assessments.

5.3. Our final proposals for the quality of service arrangements, as outlined below, incorporate a number of important changes to the existing regime. These reforms are intended to rationalise and update the outputs and standards of performance arrangements and improve the way in which GDNs' performance is measured. The existing quality of service regime, and our rationale for changing it, is discussed in earlier consultation documents including the initial proposals document[6] and the initial licence drafting consultation.[7] Significantly, we are replacing all of the overall standards of performance (OSOPs) with licence conditions or modifications to the guaranteed standards of performance (GSOPs). We consider that this will enable the Authority to take more appropriate enforcement action against the licensee in the event of a failure to meet the prescribed level of performance. This chapter sets out:

[4] This research satisfies the requirement under section 33BAA(1)(a) of the Gas Act to undertake consumer research prior to making any changes to the guaranteed and overall standards of performance. Details regarding the research, its key findings and conclusions have been published in a separate report. See Gas Distribution Price Control Consumer Research Final Report, May 2007 (ref 126/07).
[5] This included energywatch, the GDNs and Ofgem
[6] Ofgem, Gas Distribution Price Control Review Initial Proposals Document Ref 125/07 29 May 2007.
[7] Ofgem, GDPCR Initial Licence Drafting Consultation Ref 221/07, 10 September 2007.

- an overview of the quality of service arrangements to apply to GDNs;
- the key issues raised in responses to the updated proposals and licence drafting consultation, and Ofgem's position on those issues; and
- the GDNs' cost allowances in respect of the quality of service arrangements.

Overview of arrangements

5.4. The quality of service arrangements for gas distribution includes licence conditions, GSOPs, as set out in the Gas (Standards of Performance) Regulations, and a published comparison of the GDNs' performance, in the form of a balanced score card.

5.5. Below we provide a brief overview of each element. While we have prepared this summary to be helpful, we do not intend it to be a comprehensive and authoritative interpretation of the licence conditions or regulations.

Licence conditions

5.6. The licence conditions which contain provisions relevant to quality of service are Standard Special Conditions A19 to A22 as well as Standard Special Conditions D9 and D10.

Standard Special Conditions (SSCs) A19-22

5.7. These conditions set out requirements that GDNs must meet when dealing with domestic customers. The key features of these conditions are summarised in Table 5.1.

5.8. The changes to SSC A19-22 rationalise the administration requirements and ensure that the obligations are clear, focused and targeted. They are largely consistent with the supply licence review and the review of the electricity distribution licence where appropriate. Previous requirements for GDNs to produce Codes of Practice for regulatory approval have been replaced with requirements to:

- prepare statements of procedures;
- publish these statements on their website;
- take reasonable steps to inform domestic customers of these statements; and
- provide a copy on request free of charge.

5.9. The provisions for different categories of vulnerable customers have been merged and some requirements such as the obligation for GDNs to agree a password in order to enter a vulnerable customer's premises have been moved into the licence.

Table 5.1 - Summary of SSCs A19-22

Condition	Key features
SSC A19 Provision of services for specific domestic customer groups	▪ In certain circumstances, GDNs must comply with requests to reposition meters for customers who are of pensionable age or disabled or chronically sick ▪ GDNs must provide facilities so that blind, partially sighted, deaf and hearing impaired customers can complain or ask about their services ▪ if asked to do so, GDNs must agree a password to be used when visiting the premises of certain vulnerable customer groups on a job specific basis ▪ GDNs must take steps so that customers can find out about the GDNs' obligations.
SSC A20 Arrangements for access to premises	▪ GDNs must take all reasonable steps to ensure certain requirements are met when obtaining access to customers' premises; for instance they must be readily identifiable and they must avoid undue disturbance to owners and occupiers of premises ▪ GDNs must take steps so that customers can find out about the GDNs' obligations.
SSC A21 Procedure for dealing with complaints	▪ GDNs must produce and comply with a procedure for dealing with complaints made by domestic customers ▪ GDNs must take steps so that customers can find out about the GDNs' obligations.
SSC A22 Reporting on performance	▪ GDNs must provide certain information relating to their dealings with domestic customers and their performance under the Gas (Standards of Performance) Regulations.

5.10. We have considered the relationship between our proposed changes to SSC A21 and the new requirements being introduced pursuant to the Consumers, Estate Agents and Redress Act 2007 (CEAR Act). This is discussed further in paragraph 5.42 and 5.43 below.

SSC D9 - Distribution Network transportation activity incentive scheme and performance reporting

5.11. This licence condition requires GDNs to submit certain information in a specified form. Table 5.2 provides a high level summary of the information that must be submitted by GDNs. The purpose of this information is to enable Ofgem to monitor GDNs' performance in key areas of service.

Table 5.2 - Summary of information to be submitted under SSC D9

Activity	Information required
Interruptions	The number and duration of interruptions experienced by customers (other than interruptions that occur pursuant to contract). GDNs must also meet certain data quality requirements.
Customer satisfaction surveys	The results of surveys that canvass the views of customers who have experienced: a planned interruption; an unplanned interruption; a gas emergency and/or a gas repair; or services from the GDNs' connections businesses.
Environmental performance	Includes loss of containment from gas storage.
Accuracy of pipe-line records	Includes: ▪ the number of asset error correction reports submitted per year; ▪ the number of pipe-line records digitised per year; ▪ the number of pipe-line records awaiting digitisation; and ▪ the date of the oldest pipe-line record awaiting digitisation.
Supporting information	Other information regarding gas escapes, gas in buildings and cast iron mains fractures or as specified by the Authority.

5.12. The main changes are to introduce reporting on the accuracy of pipe-line records, to introduce a requirement for the GDNs to carry out customer satisfaction surveys where customers have experienced an emergency or service from the GDNs' connection businesses, and to rationalise the existing reporting where there has been duplication with costs or revenue reporting.

5.13. D9 requires the GDNs to submit the information in the form, manner and frequency specified in Regulatory Instructions and Guidance issued by the Authority. It also establishes a mechanism by which the Authority can audit the systems, processes and procedures that the GDNs use to collect and prepare the specified information.

5.14. GDNs should have appropriate and robust corporate governance procedures in place to ensure that data collected and reported to Ofgem is reliable and accurate. Ofgem will be undertaking an audit of GDNs' reporting systems and data early in this price control period to ensure that this is the case. Where information is not sufficiently robust or GDNs do not have appropriate systems in place, Ofgem will take appropriate action to ensure future compliance. This could potentially include the introduction of regular external audits.

SSC D10 - Quality of service standards

5.15. SSC D10 sets out quality of service standards that apply in relation to certain activities undertaken by the GDNs. Table 5.3 provides a high level summary of the standards that must be met by GDNs.

Table 5.3 - Standards required under SSC D10

Activity	Standard
Connections	▪ 90 per cent of standard quotations must be issued within six working days (higher limits apply to non-standard quotations) ▪ 90 per cent of connections must be completed within the timescales agreed with the customer ▪ 90 per cent of replies to land enquiries must be issued within five working days ▪ in 90 per cent of cases, GDNs must provide dates for the commencement and substantial completion of work within 20 working days.
Telephone services	▪ 90 per cent of calls to the national gas emergency line, the dedicated enquiry line and the meter point reference number helpline must be answered within 30 seconds ▪ in the case of the national gas emergency line, the calls must be answered by a person.
Emergency response	▪ 97 per cent of uncontrolled gas escapes must be attended within one hour of receipt of details of the emergency ▪ 97 per cent of controlled gas escapes must be attended within two hours of receipt of details of the emergency.

5.16. The main changes are to include the emergency service standard (OS5) for attending uncontrolled gas escapes within one hour (and controlled gas escapes within two hours) and the telephony standard as licence requirements.

5.17. D10 also provides for a scheme to review the accuracy of connections quotations prepared by GDNs, and requires GDNs to undertake a regular audit of their connections services and provide the results to the Authority.

Guaranteed Standards of Performance

5.18. The Gas Act 1986 (as amended) empowers the Authority to make regulations prescribing individual ("guaranteed") standards of performance (GSOPs), with the consent of the Secretary of State. GSOPs set performance levels that must be met in each individual case. If a GDN (or IGT) fails to provide the level of service required then it must make a payments or payments to the consumer affected, subject to certain exemptions.

5.19. Table 5.4 provides a high level summary our final proposals for the GSOPs. Many of the GSOPs are subject to exemptions which are not described in Table 5.4.

Table 5.4 - High level summary of guaranteed standards of performance[8]

GS	Regulation	Guaranteed standard	Compensation if not met
1	7 Supply restoration	GT must restore customer's gas supply within 24 hours following an unplanned interruption. Further compensation must be paid for each additional period of 24 hours until supply is restored, subject to a cap. If the interruption is caused by another GT, the other GT is either required to make the payment to the GT to whose network the customer is connected or to the customer directly.	£30 (domestic) £50 (small non-domestic).[9] Cap of £1000.
2	8 Reinstatement of consumers' premises	GT must reinstate customer's premises within 5 working days. Further compensation must be paid for each additional period of 5 working days.	£50 (domestic) £100 (non-domestic).
3	9 Priority domestic customers	GT must provide alternative cooking and heating facilities to priority domestic customers when supply to the customers' premises is discontinued. GT must provide these facilities within 4 hours for planned and unplanned interruptions affecting less than 250 consumers, or within 8 hours for an unplanned interruption affecting 250 or more customers.	£24 (domestic) if claimed by the customer within 3 months.
4-6	10 Connections - Provision of quotations	GTs must provide a quotation for providing a new or altering an existing connection within: ▪ 6 working days for standard connections ▪ 11 working days for non standard ≤275kWh connections ▪ 21 working days non standard >275kWh connections. Further compensation must be paid for each additional day that failure continues subject to a cap. If the quotation is inaccurate it is treated as if it was not provided on time.	£10, or £20 for non standard >275 kWh connections. Cap is lesser of £250 (or £500 for non standard >275 kWh connections) or contract sum.

[8] The standards are subject to certain exemptions which are set out in the existing regulations and our guidance document - Guidance for reporting on Standards of Performance and Standard Special Licence Condition D10, November 2005.

[9] The standard does not apply to consumers that consume more than 73,200 kWh per year or where the interruption affects more than 30,000 consumers. Larger consumers are protected by the Uniform Network Code.

7	10 Connections - Accuracy of quotations	Where a customer challenges a quotation under the GT's published accuracy scheme and the quotation is found to be inaccurate the GT shall refund the amount of any overcharge.	Amount of any overcharge.
8	10 Connections - Response to land enquiries	GT must respond to land enquiries in respect of a new connection or alteration of an existing connection within 5 working days. Further compensation must be paid for each additional day that failure continues subject to a cap.	£40. Cap is £250 (or £500 for >275 kWh customers).
9-10	10 Connections - Timing of work	GT must offer a date for commencement of the work and substantial completion within 20 working days of the customer accepting the quotation. Further compensation must be paid for each additional day that failure continues subject to a cap.	£20 (≤275 kWh) £40 (>275 kWh) Cap is lesser of £250 (or £500 for >275 kWh customers) or contract sum.
11	10 Connections - Completing the work	GT must substantially complete a connection on the date agreed with the customer. Further compensation must be paid for each additional day that failure continues subject to a cap.	Initial payment between £20-£150 (depending on quotation amount). Cap varies depending on quotation amount, up to £9000 for quotes between £50k-£100k.
12	12 Payments	GTs must make payment required under the guaranteed standards to the customer within 20 working days from when the payment became due. Payments to other GTs under Reg. 7 (Supply restoration) must be made within 10 working days of receiving notification of the interruption.	£20
13	10A Notification of planned interruption	GTs must notify consumers at least 5 working days in advance of a planned supply interruption.	£20 (domestic) £50 (non-domestic) if claimed by the customer within 3 months.
14	10B Responding to complaints	GTs must respond to a complaint within 10 or 20 working days depending on whether a site visit or making enquiries of third parties is required. Further compensation must be paid for each additional period of 5 working days until the substantive response is provided, subject to a cap.	£20 (domestic and non-domestic). Cap of £100.

5.20. The main changes to the guaranteed standards are:

- to include smaller non-domestic customers consuming less than 73,200 kwh in the supply restoration standard;
- to include third party damage and water ingress in the supply restoration standard;
- to include situations where an interruption on one network affects customers on another network;
- to tighten the reinstatement standard to five working days;
- to include a new guaranteed standard on planned interruptions; and
- to include a new guaranteed standard for complaints.

Balanced score card

5.21. Making information available for public scrutiny is an important regulatory tool that creates strong incentives for management teams to focus on quality of service. Ofgem already publishes an annual Gas Distribution Quality of Service Report that details certain aspects of the GDNs' performance.

5.22. In future we will collate and publish some of the quality of service information in the form of a "balanced score card". Over time this will assist us in making meaningful comparisons of performance between GDNs. It will focus on GDNs' performance across a number of key areas and those measures which are most valuable to consumers and to GDNs.

5.23. We intend to implement the balanced score card described below. At this time, the different areas will not be weighted to create an overall performance score for GDNs and there will be no financial incentive attached to this measure. In future, once confidence in this data improves this may provide a basis for an incentive.

Table 5.5 - Balanced score card

Activity	Performance measure
Gas supply	▪ Number of unplanned interruptions per 100 customers ▪ Average duration of interruptions ▪ Accuracy of data submitted
Gas safety	Per cent of gas emergencies attended within prescribed timescales
Accuracy of pipe-line records	Number of undigitised mains pipe-line records
Customer service	Customer satisfaction survey results for: • Repair • Replacement • Emergencies • Connections
Complaints	Per cent of complaints responded to within prescribed timescales
Reinstatement	Per cent of reinstatement jobs completed within prescribed timescales

5.24. As the price control comes into effect on 1 April 2008 the balanced score card will appear in Ofgem's annual Gas Distribution Quality of Service Report from the 2008-09 report onwards.

Responses to updated proposals and the initial licence drafting consultation

5.25. This section considers the main issues raised by respondents to updated proposals and the initial licence drafting consultation. With the exception of the issues associated with the emergency response standard, few respondents discussed quality of service in their responses to updated proposals. This suggests that respondents are relatively satisfied with our proposals for the quality of service regime. Responses to the initial licence drafting consultation and discussions in the Quality of Service Working Group have prompted us to refine certain aspects of the regime as discussed below.

Emergency response standard

5.26. GDNs expressed concerns regarding our proposal to move the overall standard for attending 97 per cent of controlled and uncontrolled gas escapes within 1 and 2 hours into the licence without any exemptions. GDNs consider that this could result in them breaching their licence as a result of unforeseen factors beyond their control. They suggest that the obligation should be relaxed, for instance through an exemption for exceptional circumstances or the use of wording that replicates the current requirement for OSOPs set out in the Gas Act, namely, that the GDN will have satisfied the licence requirement if they have conducted their business in such a way that they can reasonably be expected to meet the performance levels set.

5.27. We do not propose to introduce an exemption. The proposed approach will allow us to protect the interests of consumers more effectively because the current status of the obligation makes enforcement extremely problematic. Contrary to the concerns expressed by some GDNs, Ofgem is not obliged to pursue enforcement actions in circumstances where the licensee is taking appropriate steps to meet the standards or if the breach is trivial. The criteria that Ofgem applies when deciding whether or not to open an investigation are set out in our enforcement guidelines which derive from the statutory provisions[10]. In deciding whether it is appropriate to take any action for breach of these standards and the nature of any such action we would take account of any relevant circumstances including whether the HSE were taking any steps in relation to the failure, whether any exceptional circumstances had occurred during the year that had an adverse impact on the GDN's performance and the action taken during the course of the year by the GDN to prevent or minimise failure.

5.28. We note that prior to 2002 the gas transporters' licence included provisions for the emergency response standard.

[10] Ofgem, Enforcement guidelines on complaints and investigations, Doc. Ref. 232/07, 28 September 2007, Chapter 3.

Passwords for vulnerable domestic customers

5.29. Several GDNs suggested that the requirement to agree a password with vulnerable customers should be on a job specific basis. Given that dealings between GDNs and consumers are highly infrequent - on average, domestic gas consumers are interrupted only once every forty years - we accept that it is more practical for the password scheme to apply on a job specific basis.

Interruption reporting

5.30. Our updated proposals document set out our intention to introduce a requirement on GDNs to meet minimum performance levels of 95 per cent completeness for data on the number and duration of interruptions and 90 per cent accuracy for data on the number of interruptions. During the quality of supply working group, GDNs questioned how this would work in practice.

5.31. We have reviewed this aspect of the quality of service arrangements and accept that if the data on the number of interruptions is complete, it will also be accurate and therefore a separate performance level on accuracy is unnecessary. Accordingly, we will only retain the requirement for data to be 95 per cent complete. We will keep this aspect of the GDNs' performance under review. If consumer satisfaction survey results suggest that GDNs' performance has deteriorated, we may wish to tighten the interruptions data quality requirements in order to understand the position better.

Consumer satisfaction surveys

5.32. There was general support for the extension of these surveys but a number of practical issues were raised by members of the Quality of Service Working Group.

5.33. It was suggested that it would be worthwhile to merge the emergency and repair surveys into a single survey. As there is a significant degree of overlap between customers who experience an emergency and customers who experience a repair, we have decided to adopt the suggestion and propose to amend SSC D9 accordingly.

5.34. Given that the surveys will cover several activities carried out by GDNs there is a risk that survey results may be affected by small sample sizes for a given activity. We consider that this problem can be addressed by increasing the sample size so that sufficient responses are received for each activity. In particular, it will be necessary to have a larger sample size for the emergency / repair surveys so that sufficient responses are received in relation to each of emergencies and repairs[11] and

[11] The number of surveys sent out by each GDN should be sufficient so that at least 200 emergency and repair surveys are completed and returned in each quarter (at least 800 each year), and at least 150 connections surveys are completed and returned in each quarter (at least 600 each year). This requirement will be subject to further consultation when we consult on the revised regulatory instructions and guidance.

a larger sample size of connections so that sufficient customers are included to cover the full connections process from quotation to substantial completion of the work.

5.35. The working group also considered the sample group to be used to select customers who would be sent the connections survey. Some GDNs recommended that the sample group should be amended to avoid the potential for the results to be affected if some surveys are only partially completed, or if the customer receives a survey when they are only part way through the connections process. Our position on this issue is unchanged, namely, the sample group should be drawn from all consumers who have applied for a quotation. The issues raised in the working group can be job be addressed by adjusting the size and timing of the survey.

5.36. The survey templates will be set out in the revised Gas Distribution Quality of Service Regulatory Instructions and Guidance, which will be consulted on in early 2008.

Accuracy of pipe-line records

5.37. Two GDNs opposed the introduction of reporting requirements relating to the accuracy of pipe-line records. We have not changed our position on this issue. Maintaining accurate pipe-line records is part of a GDN's normal business as prudent and efficient asset managers. Collecting and publishing information about the accuracy of pipe-line records will strengthen incentives on GDNs to improve this area of their performance. The detail of the reporting requirements will be set out in the revised Gas Distribution Quality of Service Regulatory Instructions and Guidance.

Supply restoration

5.38. Several GDNs considered that there were outstanding issues to be resolved in relation to the process to be followed when an interruption is caused by a failure on an upstream network. Any ambiguity in the allocation of responsibility for making compensation payments could affect consumers' ability to receive the compensation that they are entitled to. We therefore propose to amend the Gas (Standards of Performance) Regulation so that it sets out the mechanics of what happens when an interruption originating on one network affects consumers connected to another GDN or IGT network. We also intend to amend standard condition 20 (Standards of Performance) of the gas transporter's licence.

5.39. In the event that an interruption on one network affects a consumer's premises connected to another GT's network, the GT to whose network the premises is connected will initially be responsible for making payments to that consumer for any failure to restore. However, this GT will be able to claim an exemption if the interruption originated on another GT's network. Where the GT to whose network the consumer's premises is connected wishes to claim an exemption on this basis it must notify the other GT and provide appropriate information within five working days. The other GT then becomes liable, and must pay the GT to whose network the consumer is connected or the relevant gas shipper within ten working days. Where relevant, the GT to whose network the consumer is connected must then pass on these payments to the consumer within five working days. These arrangements ensure that the consumer receives the payment within 20 working days, regardless of where the interruption occurred and which GT is liable for payment.

Notification of planned interruptions

5.40. GDNs expressed concern that the new requirements in the standard for planned interruptions would restrict operational efficiency and would be a backward step from the existing service provided by the GDNs' customer liaison teams. GDNs also raised practical concerns regarding the requirement to give at least one working day's warning if they are unable to keep to the specified window.

5.41. GDNs' consumer satisfaction surveys generally give positive feedback in relation to the GDNs' efforts to notify consumers of planned interruptions. We have therefore decided to limit the standard to a requirement for GTs to provide at least five working days prior notice of the interruption. We will keep this aspect of the GDNs' performance under review. If consumer satisfaction survey results suggest that GDNs' performance has deteriorated, we may wish to reconsider this standard.

Complaints handling

5.42. We have considered the relationship between the complaints handling standard and the new requirements that are likely to be introduced pursuant to the Consumers, Estate Agents and Redress Act 2007 ("CEAR Act").[12] We have also discussed the standard at the quality of supply working group.

5.43. While the scope of the CEAR Act 2007 on complaints handling is distinct from the scope of Gas Act provisions that empowered us to make the Gas (Standards of Performance) Regulations, we will adopt a consistent approach where appropriate.

Visibility of performance

5.44. One respondent expressed concern that the revocation of the overall standards of performance (OSOPs) would reduce the visibility of the GDNs' quality of service. We will ensure that there is no reduction in visibility of performance as a result of the revocation of the OSOPs. Where the OSOPs have been migrated to licence conditions or GSOPs, we will continue to report on them in the annual quality of service report. In addition, we propose to amend SSC D10 to require GDNs to include the emergency response standard and the telephone service standard in the notice of rights that they provide to suppliers each year. GDNs are already required to include the GSOPs in the notice of rights.

[12] Ofgem, Complaint Handling Standards Consultation Doc. Ref. 272/07, 9 November 2007.

Cost allowances for the quality of supply arrangements

5.45. As part of the previous price control, GDNs were given an allowance for an efficient level of payments under the supply restoration guaranteed standard. They were also given an allowance to procure insurance against large third party water ingress (TPWI) incidents and an allowance for payments that fell into the insurance excess.

5.46. We consider it appropriate to provide GDNs with an allowance for an efficient level of compensation payments for the supply restoration guaranteed standard, both for unplanned and TPWI interruptions for this price control period. GDNs will be able to use this allowance to manage the impact of the events through faster restoration of supplies and/or to insure against potential payments. We have calculated an allowance which is shown in Table 5.6. The allowance, and the methodology used to calculate it, has not changed since the updated proposals document.

Table 5.6 - Average annual opex for quality of service arrangements 2008-13 (£m, 2005-06 prices)

		Payments under supply restoration standard		Additional customer satisfaction surveys	Planned interruption standard	Consumer redress	TOTAL
		Unplanned	TPWI				
NGG	East of England	0.07	0.20	0.04	0.05	0.04	0.38
	London	0.39	0.16	0.04	0.03	0.02	0.64
	North West	0.02	0.12	0.04	0.04	0.03	0.24
	West Midlands	0.01	0.06	0.04	0.03	0.02	0.15
NGN	Northern	0.13	0.10	0.04	0.03	0.02	0.31
SGN	Scotland	0.06	0.07	0.04	0.01	0.02	0.19
	Southern	0.05	0.22	0.04	0.03	0.04	0.37
WWU	Wales & West	0.01	0.09	0.04	0.02	0.02	0.18
	TOTAL	**0.74**	**1.01**	**0.28**	**0.22**	**0.21**	**2.46**

5.47. These amounts have been included in our opex forecasts.

Scope of networks

Sub-deducts networks survey

5.48. Under section 6A of the Gas Act 1986, the Secretary of State has powers to grant class or individual exemptions from the prohibitions under section 5(1) of the Gas Act 1986 on unlicensed conveyance, shipping or supply of gas. Since 1996, the Secretary of State has made several class and individual exemption orders including a statutory instrument[13] that is relevant to the “sub-deduct” networks (as referred to in the licence and the Uniform Network Code. Schedule 2A[14] (Exception to prohibition on unlicensed activities) to the Gas Act is also relevant. The statutory instrument sets out an exemption for conveyance of gas in cases of secondary metering. The statutory instrument is due to expire in March 2011.

5.49. There are circa 1,700 sub-deduct networks[15] with approximately 3,300 end users of which approximately 50 per cent are domestics. No new sub-deduct arrangements have been developed since 1996. Ownership and maintenance responsibilities including gas safety are not clearly defined for these networks. This uncertainty raises potential concerns with regard to gas safety on these networks and the risks faced by end users and the general public. Following extensive discussion with the HSE and the GDNs there appears to be general agreement in principle that the preferred solution is for the GDNs to adopt sub-deduct networks. This would ultimately result in the GDNs having ownership and maintenance responsibility for the sub-deduct networks. However it is apparent from extensive cross industry discussion that there is very limited information available about the physical characteristics of these networks.

5.50. Further to this we outlined in our updated proposals document that we were willing to make provision in the GDNs' allowed revenue for a survey of sub-deduct networks. The purpose of this survey would be to gather the technical data relevant to potential adoption, such as the extent and nature of the assets. We also invited views from the GDNs on the costs, timing and other practicalities involved in conducting such a survey.

5.51. Having considered the representations made by the GDNs we have set an allowance for each GDN to conduct a technical survey of sub-deducts networks attached to their systems. The survey will seek to establish the following technical information:

- ownership and access issues;
- location and layout of sub-deduct networks (length of pipes, proximity of pipes to buildings and distance from DN network etc);
- the pressure of gas on each network;
- existence of other equipment (Governors, Boosters etc); and
- potential difficulties associated with future re-engineering.

5.52. Ofgem does not envisage that the survey would seek to establish the structural integrity of any pipe work beyond a visual inspection at this stage. Underground or concealed pipe work will not be subject to excavation. It is envisaged that the survey work should be completed within two years. The allowance to cover the costs of the survey has been set at £1000 per network.

[13] Statutory Instrument (SI) 1996/449, the Gas Act 1986 (Exemptions) (No.1) Order 1996.
[14] Schedule 2A is repealed by the Utilities Act 2000 though the repealing provisions are not yet in force.
[15] Xoserve data, November 2007.

Table 5.7 - Sub-deduct survey allowance, (2005-06 prices)

DN	No of sub-deduct Networks[16]	Total Allowance (£ 000)	Year 1 (2008-9) (£ 000)	Year 2 (2009-10) (£ 000)
Eastern	171	171	86	85
London	215	215	108	107
North West	149	149	75	74
West Midlands	473	473	237	236
Northern	162	162	81	81
Scotland	51	51	26	25
Southern	328	328	164	164
Wales & West	210	210	105	105
Total	1,759	1 759	882	877

5.53. The survey findings will be submitted to Ofgem in a report from each of the licensees, detailing the relevant technical information. This report will then provide Ofgem with the necessary data to progress towards determining the cost associated with re-engineering of sub-deduct networks. The report will also inform the expected DBERR policy consultation on the replacement statutory instrument.

[16] Xoserve data, November 2007

6. Incentives

Chapter Summary

This chapter sets out our final proposals for:
- a capex rolling incentive;
- a mains replacement incentive;
- a capacity outputs incentive; and
- a loss of meter work revenue driver

The chapter also explains why we decided not to implement an opex rolling incentive.

Introduction

6.1. As part of the price control we have historically included additional incentives to counteract any perverse incentives that may arise from RPI-X regulation. As part of the GDPCR we have reviewed the existing incentives, considered enhancements to the incentives, such as the rolling incentives and the loss of meter work revenue driver, and have removed or amended incentives where we considered that they did not have the desired effect; for example, we removed the volume driver as set out in paragraphs 2.1 to 2.4.

6.2. This chapter sets out the issues associated with the incentives we have considered as part of the GDPCR and our final proposals for each of the incentives. Additional incentives and other mechanisms connected to the theme of sustainable development are set out in chapter 7.

Rolling incentives

6.3. Under RPI-X GDNs have an incentive to outperform against their allowances as they retain the savings for the remainder of the price control period. Consequently GDNs have stronger incentives to make savings at the start of the price control when savings are retained for a longer period than mid way through the control. Our concern is that the incentives could influence the extent and timing of efficiency savings for capex and opex spend. Rolling incentives address this issue by ensuring that the GDNs retain the savings for a fixed duration regardless of when the savings are made. Any variances in the retention of savings over a price control are adjusted for at the end of the 5 years.

Capex rolling incentives and the IQI

6.4. Under a capex rolling incentive the incentive rate is fixed over the price control period. Our concern with this approach was that, as the rolling incentives effectively strengthened capex incentives, particularly mid way through the control, GDNs would have increased incentives to inflate their capex forecasts.

6.5. Traditionally, the capex allowance is set based on our views of the GDNs' capex forecasts. GDNs also have an incentive to inflate their capex forecasts in order to maximise their scope for outperformance. There is also a significant information asymmetry between the regulator and the company. It can be difficult for the regulator to differentiate between additional investment necessary to maintain network integrity and artificially inflated capex forecasts.

6.6. We addressed this concern by implementing the IQI which was developed as part of DPCR4. The IQI manages this risk by allowing the GDN to choose higher allowances than we forecast but incentivises them not to inflate their bids. The incentive does this in two ways – by giving additional income to companies who forecast capex spend close to our assessment and by providing these companies with a higher capex rolling incentive rate than those companies with higher capex forecasts, thereby increasing the reward those companies receive for outperformance.

6.7. We therefore proposed to implement the IQI alongside capex rolling incentives. Table 6.1 below sets out our proposal for the IQI matrix. A detailed explanation of the matrix is included in paragraphs 6.6 to 6.11 of the initial proposals document.

Table 6.1 - The IQI matrix

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

6.8. In table 6.2 below, we have set out each GDN's ratio for the IQI. It shows each GDN's initial forecast of their allowances, our assessment, the ratio between our assessment and the GDNs' forecast and the allowance, incentive rate and additional return (which takes the form of a cash bonus) arising from the ratio. We have applied the same ratio to all GDNs in the same group ownership to avoid any perverse incentives to focus investment in one network over another.

Table 6.2 - IQI results

	Total 5Yr capex + repex forecast	Total 5Yr capex + repex allowance (pre IQI)	IQI Ratio	Incentive strength	Additional income
	£m	£m			£m
East of England	754.8	703.0	107.6	36%	10.9
London	758.1	679.4	107.6	36%	8.9
North West	715.0	607.2	107.6	36%	9.5
West Midlands	462.0	440.2	107.6	36%	7.1
Northern	694.6	625.4	108.8	36%	8.4
Scotland	512.5	438.3	114.4	33%	3.0
Southern	1,266.8	1,090.3	114.4	33%	7.3
Wales and West	754.7	633.6	114.0	33%	4.5
Total	**5,918.6**	**5,217.4**			**59.7**

6.9. The IQI ratio is based on each GDN's total repex and capex forecast compared to our assessment with some adjustments, in particular it excludes LTS capex and riser costs.

6.10. For mains and services repex we have used the same workloads for both the GDNs' and our assessment, with some normalised adjustments, but have used the GDNs' and our unit costs to determine the ratio.

Opex rolling incentives

6.11. Opex savings tend to be recurring and can result in short term additional costs; e.g. investing in IS could lead to a short term increase in costs but lower costs over time. The way that GDNs make opex savings can therefore conflict with the opex incentives. Superficially, it would appear that GDNs have a reduced incentive to achieve opex efficiency as the price control progresses and may be unwilling to incur additional costs in the middle of the price control if they will not be able to retain the benefit that accrues for more than one or two years.

6.12. Opex rolling incentives can address these problems by enabling the GDNs to retain any incremental opex savings they make for a fixed period of time regardless of when the savings were made. However, we have examined the impact of using the benchmarking method to set allowances on the problems of periodicity. Under benchmarking, most GDNs' allowances are not set by reference to their own costs in the previous price control, but by reference to the benchmark. The exception to this is the GDN(s) whose costs are used for the benchmark. Therefore most GDNs can reasonably expect that any savings they make will be maintained into future price controls. This effectively deals with the periodicity issue. A rolling incentive applied on top of this would effectively double-count the savings.

6.13. As noted above, the exception is for the benchmark GDN(s). So a potential approach is to restrict the incentive to those GDNs that set the benchmark. However, under bottom-up benchmarking this becomes very complex to apply, as different GDNs set the benchmark for different areas of activity. It would entail very careful policing of the boundaries between different areas of costs. We intend to do this in any case through cost reporting, but it still represents a gaming opportunity for GDNs.

6.14. On balance we have decided not to implement an opex rolling incentive for this price control. We have addressed some of the concerns surrounding areas of spending that often only pay off in the long-term by introducing an innovation funding incentive for sustainable development (IFI/SD) for gas distribution, and giving explicit consideration to the costs of apprentices and training in our opex forecasts.

Mains replacement incentive

6.15. As part of the 2002 price control review we set a mains replacement allowance with a supplementary incentive which adjusted GDN revenue depending on the volume and diameter mix of mains replacement. This was in response to the HSE requirement to accelerate the replacement of iron mains within 30 metres of premises over 30 years in response to safety concerns. The supplementary incentive provided the GDNs with flexibility to vary their annual spend in line with their need to replace a different diameter mix of pipes from that originally forecast. It also protected consumers by capping the mains replacement allowance to the total of the five year forecast of spend.

6.16. As part of the initial proposals we undertook an impact assessment of the mains replacement incentive. The analysis shows that it has worked well to provide GDNs with flexibility over the diameter mix of mains replaced while keeping the unit costs of mains replacement down. However we considered that there should be some refinements to the mains replacement incentive. We proposed to include three classes of service work associated with mains replacement (re-laid services associated with mains replacement, service test and transfer to new or other mains and non domestic service replacement). We also proposed to include unit costs for three additional larger pipe diameter sizes, as set out in initial proposals.

6.17. We consider that the incentive rate to apply to this mechanism should be equal to the capex rolling incentive as determined by the IQI (see table 6.2 above). This will apply symmetrically.

6.18. We have decided to set the cap on the mains and services incentive at the aggregate of the five year forecast of expenditure but with any overspend that has not already been accounted for through the mains and services incentive being subject to the capex rolling incentive. This ensures that the treatment of costs in excess of the cap is consistent with the capex rolling incentives. If a GDN manages to spend within the overall five year allowances, then there will be no adjustment. If it spends more than the overall five year allowance, then the penalty under the rolling incentive will be adjusted for any penalties already incurred on an annual basis under the mains and services incentive, so that it is not penalised twice for the same overspend. We do not intend to aggregate the totals for GDNs with the same owner.

Capacity outputs incentive

6.19. GDNs have a licence obligation to develop and maintain their pipe-line system to enable them to meet gas demand on their networks in the event of a 1 in 20 peak demand day(s). GDNs meet this standard through a combination of investment in their own pipe-line network, procuring interruption services on their own network, and booking flat and flexibility exit capacity from the NTS. The capacity outputs incentive is intended to incentivise GDNs to make efficient use of the capacity management outputs available to them, including making efficiency trade-offs between the options where possible. The incentive for the transitional offtake period expires on 30 September 2011. As part of final proposals it is necessary for Ofgem to implement a capacity outputs incentive covering the period 1 October 2011 to 31 March 2013.

6.20. In updated proposals we consulted on the scope, form and structure of a capacity outputs incentive to apply from 1 October 2011. The consultation proposed a sliding scale mechanism for flat capacity, a sliding scale mechanism for interruption payments, sought views on the merits of not incentivising flex, and sought views on whether it would be appropriate to develop a capex reopener criterion as part of the incentive scheme. We also consulted on the methodology we would use for setting the flat capacity volume targets, and the methodology we would use for setting the interruption target, but the updated proposals consultation did not include values for the incentive parameters.

6.21. On 23 October 2007 we published a follow up consultation[17] to the updated proposals consultation. We used the October consultation to publish proposed values for the flat capacity incentive, to publish proposed values for the interruption incentive, to restate our intention to consider not implementing a flex incentive, and to provide more detail on the capex reopener criteria. We also consulted on changes to the sharing factors proposed for the flat capacity and interruption incentive, and to consult on changes to the way in which we proposed to calculate the value of the interruption incentive. These changes reflected a further development in our thinking regarding the capacity outputs incentive relative to the proposals consulted on in updated proposals.

6.22. Under the transitional exit capacity incentive the Income Adjusting Event (IAE) threshold was reduced to £1 million per formula year for each GDN, but from formula year 2012-13 it is scheduled under the licence to return to a value of £2 million. In our October consultation we recognised that in applying the same absolute value to each GDN, the existing IAE threshold did not reflect the differing size of each GDN business and sought views on whether it would be more appropriate for this

[17] Capacity outputs incentive for GDPCR – October Update Consultation, Ofgem, 23 October 2007.

threshold to take an annual value equivalent to 0.5per cent of allowed revenue for each GDN.

Respondents' views

6.23. In their responses to updated proposals the GDNs considered that the proposal to set the interruption incentive at the level of the annuitised value of the cost of reinforcing location network constraints would be an appropriate way of incentivising efficient investment outcomes for Network Sensitive Load (NSL) supply points, but none of the GDNs agreed with Ofgem that the savings they could achieve through outperformance of the flat capacity incentive would be sufficient to promote efficient investment outcomes on other parts of their networks. A majority of all respondents considered that in the absence of evidence of a scarcity of flex it would be reasonable to consider not implementing a flex incentive. A majority of respondents also agreed that to accommodate the uncertainty associated with the first interruption auctions it would be appropriate for a capex reopener provision to apply. The GDNs considered that it was important that investment triggered as a consequence of storage constraints should be eligible for consideration under the capex reopener. A non-GDN considered that in the event that a GDN required to apply for a capex reopener, a full industry consultation should precede Ofgem's final decision.

6.24. Respondents to the October consultation welcomed Ofgem's revised proposal to determine the interruption incentive targets based on the annuitised cost of the investment required to support all interruptible customers as firm, and a majority of respondents agreed that the proposed change to the sharing factors associated with this incentive were compatible with the changed methodology. A majority of respondents continued to consider that not implementing a flex incentive would be the right policy decision, but National Grid Gas Transmission did not share this view and considered that a decision not to incentivise flex may have a detrimental effect on the efficient management of the transmission system. A detailed summary of responses to the updated proposals consultation on the capacity outputs incentive and the October update consultation is contained in appendix 4.

6.25. A majority of respondents who commented on Ofgem's proposal to set the IAE threshold at an annual value equivalent to 0.5 per cent of allowed revenue for each GDN supported this proposal. One GDN considered that basing the IAE threshold on a percentage of allowed revenue could unfairly penalise some GDNs in the event that an offtake reform proposal is implemented which requires GDNs to pay the NTS directly for exit capacity. One GDN opposed the 0.5 per cent of allowed revenue threshold on the basis that it could result in some larger GDNs having an IAE of more than £2 million.

Interruptions

6.26. Setting a capacity outputs incentive for the period from 1 October 2011 is complicated by a number of factors, including uncertainty surrounding the form and timescale for introduction of the enduring offtake arrangements and uncertainty about the outcome of the first interruption auctions. The first interruptible rights associated with the 2008 interruption tender come into effect on 1 October 2011, and it is important that the incentive is compatible with the new interruption regime[18].

6.27. By allowing customers to reveal the value they place on interruption the reformed arrangements should enable the GDNs to make better trade-offs between contracting for interruption versus reinforcing their own pipe-line network and booking incremental NTS flat capacity. However, moving from an administered set of interruption arrangements to a market allocation of interruption carries some uncertainty. At the moment GDNs know what the availability of interruption is at the level of the current transportation charges capacity discount. However, in advance of the first round of interruption auctions, absent any information about the interruptible customers' elasticity of demand, it is difficult for the GDNs to have certainty over the numbers of customers who will bid at a price which makes it economic for them to be accepted as interruptible. This uncertainty makes forecasting how much the GDNs will pay for interruption difficult.

6.28. We consider that it is appropriate that the interruption incentive target should be set at a level which incentivises the GDNs to contract for interruption up to the point at which it becomes more efficient to reinforce their networks to make customers firm. In updated proposals we took the view that this would equate to the annuitised cost of the reinforcement projects necessary to remove locational constraints on the GDNs but, following further analysis, in our October consultation we indicated that our view of the efficient level to set the interruptions incentive had changed.

6.29. Our analysis of the capacity output options at the time of updated proposals was based on the view that the GDNs tend to require interruption for two specific reasons: to manage the capacity needs of specific locational constraints or, at the margin, to manage the overall level of peak day demand. We took the view that the generic interruption that the GDNs may need to manage peak day demand can be traded to some extent with NTS flat capacity, while trade-offs at location specific constraints are more directly between pipe-line reinforcement and interruption. At a high level we continue to consider that our understanding of this relationship is well founded but, as indicated in our October consultation, we are now also aware that the discrete trade-offs between NTS flat capacity and interruption are not infinite and, for some GDNs, only exist assuming a certain minimum level of interruption is available. We also now consider that a shortfall of interruption and NTS storage combined could result in GDNs having to invest in distribution network flexibility. This more detailed analysis of the relationship between the GDNs' capacity management options was supported by the GDNs in their responses to our October consultation.

[18] In March 2007 Ofgem directed the implementation of Network Code Modification Proposal 90 'Revised DN interruption arrangements' from 1 April 2008. The reformed DN interruption arrangements change the way that interruption rights will be allocated. Instead of large customers determining their own interruptible status, via annual tenders with three year lead times, the reformed arrangements will allow GDNs to offer interruption capacity solely in the locations and volumes they require.

6.30. On the basis that NTS flat capacity on its own would be an insufficient substitute if the GDNs were unable to contract for any generic interruption, we intend to set the interruption incentive based on the discounted cost of the network reinforcement investment required to support all interruptible customers as firm, not just the discounted cost of the projects necessary to remove locational constraints. The incentive under consideration will apply for an eighteen month period at the end of the forthcoming price control period. We consider that unnecessary capex triggered as a consequence of the way the interruption incentive is set would be among the least desirable outcomes of the first interruption auctions. We consider that the relatively cautious approach of setting the interruption target at a level equivalent to the maximum amount it would be efficient for the GDNs to pay for interruption is the one most likely to promote efficient outcomes.

6.31. Dependent on the level of bids which the GDNs receive for interruption we recognise that there is a strong probability of the GDNs outperforming this incentive. Consistent with our October consultation, to protect customers from any windfall gains by the GDNs, we consider that the interruption incentive should be subject to 50 per cent sharing factors. We also consider that the power of the sharing factors should not be constrained by caps or collars.

6.32. In appendix 1 of our October consultation we published a table listing, for the purposes of calculating an incentive, estimates of the investment costs necessary to support all customers as firm by GDN. This data was based on information provided to Ofgem by PB Power in their October Capex/Repex update report. Discounted over a forty five year period using the cost of capital modelling assumption published in updated proposals (4.84 per cent vanilla WACC), we calculated what the annuitised value of each of these estimated costs would be and proposed that these values should form the basis of each GDN's interruption incentive target. We continue to consider that this approach represents an appropriate way of establishing interruption incentive targets for the GDNs.

6.33. Table 6.3 contains our revised estimates of the investment costs necessary to support all customers as firm by GDN. The updated estimated investment costs have been adjusted in some cases to take account of final proposals on capex allowances for the GDPCR, and have been uplifted in each case from 2005-06 prices to take account of four years real price effect (RPE) at 2.4 per cent. We consider that 2009-10 represents a reasonable mid-point estimate of when investment costs triggered as a consequence of interruption reform would most likely be incurred. In establishing the RPE assumption to apply to this capex we have taken a weighted average of the RPE for direct labour, contract labour and material prices based on the relative performance of each within capex. A full discussion on RPE can be found in chapter 3. We have calculated the annuitised value of the investment costs by discounting over a forty five year period using the cost of capital on which final proposals are based (4.94 per cent vanilla WACC).

Table 6.3 - Revised investment costs to support all customers as firm

GDN	Estimated cost in £m of all interruptibles as firm	Annuitised value £m over 45 years at 4.94%
East of England	99.0	5.4
London	2.7	0.2
North West	66.0	3.6
West Midlands	1.0	0.1
Northern	61.0	3.3
Scotland	52.0	2.8
Southern	70.0	3.8
Wales & West	149.0	8.1
Total	500.0	27.2

6.34. Under the transitional exit capacity incentive the interruption incentive target covering the period 1 October 2008 – 30 September 2011 is set to zero. We intend to consult on the appropriate interruption incentive value for this period in advance of 1 October 2008.

6.35. In the October consultation we estimated that, using the methodology consulted on, the total value of the GDNs' interruption incentive target would be approximately £25.3 million per annum. Using our updated estimates of investment costs and applying our RPE assumptions to 2009-10, we consider that this value will now be approximately £27.2 million per annum. This figure compares to an equivalent value for the capacity charges discount received by interruptible customers under the existing interruption arrangements of approximately £39 million[19]. This value is dependent on the level of transportation charges levied, but at a conservative estimate we would expect that, all other things being equal, the effect of setting the interruption incentive target using this methodology would be to reduce the overall level of transportation charges paid by distribution network customers who were not previously interruptible.

Flat capacity

6.36. In updated proposals and in our October consultation we outlined our intention to set an NTS flat capacity volume target based on forecasts of the flat capacity needs of each distribution network assuming all supply points on their networks, other than customers currently nominated as Network Sensitive Loads (NSLs), are firm. We continue to consider that this represents an appropriate basis for setting the flat capacity incentive. If the GDNs consider that they will gain under the flat capacity incentive by paying for interruption, which will allow them to decrease their NTS flat capacity bookings, then we would expect them to trade these gains off

[19] Based on 1 October 2007 distribution network charges and assuming interruptible customers pay LDZ capacity charges based on bottom stop SOQ

against the interruption incentive. We consider that the effect of changing the methodology used for determining the size of the interruption incentive will improve the efficiency of this trade off.

6.37. In updated proposals we noted that it was important where possible for the interruption incentive and NTS flat capacity incentive to have equally powered sharing factors. In our October consultation, in view of the proposal to apply 50 per cent sharing factors on performance against target for the interruption incentive, we considered that it would also be appropriate for 50 per cent sharing factors to apply to the GDNs' flat capacity incentive, and we continue to consider that this would be the case. Consistent with the transitional exit capacity incentive, we consider that it is appropriate that the GDNs should not face unlimited exposure under the flat capacity incentive. Under the transitional exit capacity incentive the GDNs have an incentive cap which is the minimum of 7.5 per cent of the cost target or £5 million, as well as an incentive collar also set as a minimum of 7.5 per cent of the cost target or £5 million. We consider that this represents a reasonable level of risk for the GDNs to be exposed to and have decided to apply the same caps and collars to the flat capacity component of the capacity outputs incentive. With 50 per cent sharing factors the 7.5 per cent caps and collars on this incentive will not be reached until GDN performance is 15 per cent above or below the incentive target, but we note that this change will not affect the overall level of exposure which the GDNs face.

6.38. The incentive targets are shown by exit zone in table 6.4 below. They are broadly equivalent to those published in the October consultation, which were aggregated at an LDZ level.

Table 6.4 - Flat capacity incentive targets

		Flat Capacity (GWh)	
GDN	LDZ Exit Zone	2011-12	2012-13
East of England	EA1	39.55	44.05
	EA2	52.93	53.38
	EA3	62.10	63.29
	EA4	249.92	253.48
	EM1	133.76	135.33
	EM2	96.04	96.12
	EM3	309.49	314.72
	EM4	25.70	25.83
London	NT1	15.64	21.61
	NT2	177.02	184.73
	NT3	324.55	315.81
North West	NW1	305.11	307.11
	NW2	296.51	301.85
West Midlands	WM1	114.85	116.63
	WM2	224.33	226.96
	WM3	125.85	126.15
Northern	NO1	267.66	271.07
	NO2	32.03	33.12
	NE1	268.74	272.75
	NE2	74.11	74.96
Scotland	SC1	69.87	70.34
	SC2	89.70	90.87
	SC4	268.84	271.81
Southern	SE1	492.57	500.73
	SE2	111.52	113.36
	SO1	124.08	126.34
	SO2	347.80	354.12
Wales & West	SW1	38.88	40.77
	SW2	177.03	178.21
	SW3	105.12	106.55
	WA1	60.47	61.13
	WA2	269.65	272.18
Total		5351.41	5425.35

6.39. The first six months of the 2011-12 formula year are covered by the transitional offtake exit capacity incentive and the GDNs already have flat capacity targets for this period. The new targets to apply to the second six months of the 2011-12 formula year are detailed above. The targets listed for 2012-13 will apply to the full formula year.

6.40. In their responses to our October consultation a number of GDNs commented on which exit capacity charge the flat capacity incentive should reference for the purposes of calculating performance against target. Under the transitional incentive, performance against target is calculated with reference to outturn exit capacity charges. A number of GDNs consider that where outturn exit charges vary relative to charges prevailing at the time capacity is booked, this has the potential to undermine the efficiency of booking flat capacity relative to other capacity management options. Promoting efficiency is the primary objective of the capacity outputs incentive. In view of the fact that under any capex reopener application, the efficiency of the GDNs' investment decisions will be, among other things, evaluated with reference to flat capacity charges prevailing at the time of investment, we consider that it would be consistent and appropriate that performance against target on the flat capacity incentive should reference the exit capacity charge at the time of booking as well. We intend to reflect this change relative to the transitional exit incentive in the licence drafting associated with this incentive.

6.41. In updated proposals we also sought views on whether the targets for the flat capacity incentive should vary with changes in the calorific value (CV) of gas. This consultation question was based on a perception that changes in CV which altered the volumes of gas that the GDNs needed to book from the NTS, could adversely affect the GDNs' performance against the flat capacity incentive in a manner beyond their control. Following further consideration we no longer consider this potential shortcoming to be a credible property of the incentive and we do not propose to adjust the GDNs' flat capacity targets for changes in CV in the forthcoming price control period. Ofgem notes that the capacity targets which form the basis of the GDNs' flat capacity incentive are in fact energy targets and are expressed in GWh. If the GDNs were incentivised using volumes of gas in mcm, changes in CV would affect performance against the incentive but, since the incentive is based on energy booked this should not be the case. If the CV at a particular exit point falls, more capacity may require to be booked, but the effect that this has on the total energy transported should in theory be neutralised by the fall in the CV. Providing the GDNs performance against target is evaluated using an accurate volume to energy conversion there is no reason to suppose that the GDNs will be adversely affected by changes in CV.

Flex capacity

6.42. In the context of the industry dialogue on NTS flex capacity associated with the enduring offtake reform proposals[20], in updated proposals we sought views on whether industry parties considered that there was a need to incentivise GDNs' bookings of flex within the forthcoming price control period. We did not offer significant new analysis of this issue in our October consultation, but we did note that, in the absence of a flex incentive, it might be appropriate to protect against the potential that NTS flex might be booked inefficiently, by subjecting the GDNs' flex bookings to explicit scrutiny in the event that they changed by more than ten per cent per annum.

6.43. In their responses to updated proposals and the October consultation, a majority of shippers and GDNs considered that if flex is not constrained it would be appropriate not to constrain GDNs' decisions in respect of flex by incentivising its

[20] On 5 April 2007 Ofgem directed the implementation of Network Code Modification Proposal 116V 'Enduring offtake reform', but following an appeal by E-ON on 10 July 2007, the Competition Commission (CC) quashed Ofgem's decision to implement this variant of the offtake reform proposals.

use. NGG Transmission did not agree with this view. In their response they considered that 'unless GDN flex bookings are controlled via an incentives mechanism, there is a risk that GDNs preferentially book NTS exit flex capacity rather than invest in their own networks', they further noted that this 'could lead to constraints on the NTS which could disadvantage other NTS users or other GDNs'. NGG Transmission disagreed with Ofgem's view that protection against this tendency could be provided by subjecting GDNs booking of flex to explicit scrutiny in the event that they increased by more than 10 per cent. They argued that this number was arbitrary and considered that it wrongly implied that any increase below the threshold would be acceptable and available from the NTS.

6.44. Ofgem understands that because NTS does not invest for flex capacity alone, and thus NTS flex capacity is produced as a by-product of investing for flat capacity, there is difficulty in establishing a marginal cost for incremental flex. By contrast, the cost to the GDNs of investing on their own networks for storage is more readily defined. Figures previously provided by the NTS in the context of enduring offtake suggest that, nationally, the current use of flex is significantly below their agreed baselines under their price control, albeit there may be specific zonal constraints. On this basis we consider that where incremental flex can provide a positive benefit to GDNs in meeting their 1 in 20 peak day obligations, allocating a maximum amount of flex capacity is likely to contribute towards a more efficient development of the GDN pipe-line system.

6.45. NGG NTS cautions that without a flex inventive the GDNs may have a tendency to book NTS flex capacity rather than invest in their own networks. On balance we consider that the risk that GDNs overbook flex to such an extent that they generate constraints on the NTS in the short period for which we have proposed no incentive on flex (18 months) is outweighed by the risk that GDNs undertake incremental investment on their own system that leads to greater overall costs to consumers, simply because they are reacting to an incentive that implies a marginal cost of flex that we cannot be confident is cost-reflective. To mitigate the risk of the former event we propose to monitor GDNs' flex bookings as discussed in paragraph 6.48 below.

6.46. The increased capacity management flexibility that the reformed interruption arrangements will offer the GDNs will, among other things, result in the GDNs having to consider the optimal mix of capacity outputs they require. One possible outcome of having the flexibility to contract for interruptible capacity only in the volumes and locations they require it, may be that the GDNs choose to reduce the overall level of interruption they contract for, and instead seek to book incremental flex from the NTS to compensate for any loss of linepack on their own network. We do not necessarily suggest that this will be the case, but we would consider that if the ability to allocate flex capacity fully on the NTS was inhibited, the overall efficiency of the gas transportation system would be compromised.

6.47. Ofgem is currently reviewing the best way to progress reform of the enduring offtake arrangements following the Competition Commission's decision to uphold in part the appeal of Mod 116V. Whether or not a market allocation of flex capacity is introduced as part of the enduring arrangements, our view that it may be appropriate to consider not incentivising flex, as explained in updated proposals, is based on the clear view expressed by industry during the consultation on the offtake proposals (and in the subsequent appeal) that there is no shortage of flex capacity and that demand for the product is not anticipated to increase significantly. Building on this view, we also now consider that, on the basis that neither customers, shippers nor GDNs are charged specifically for flex capacity, and that the NTS receives no investment signals for flex that would increase the cost to customers in providing it, it is not clear what type of efficiency benefits a flex incentive would deliver.

6.48. In the event that the sunset clause on the transitional offtake arrangements is extended, we note that overall responsibility for the allocation of flex capacity rights would remain with the NTS. Given that the NTS will reserve the right to refuse flex capacity requests which it cannot meet via the OCS booking process, and given that the flex capacity which the NTS can provide will be deliverable at no extra cost, we are not convinced that incentivising the GDNs bookings of flex in the period 1 October 2011 to 31 March 2013 is necessary or efficient. We do recognise that although there is not currently considered to be a shortage of flex, the supply of flex is not infinite and if demand for the product did change significantly constraints could occur. Where flex is a useful service to GDNs we would welcome its fullest allocation, but we would share the concern of the NTS if GDNs sought to book it unnecessarily. To this end we consider that it would be appropriate for the GDNs to be required through their licence to write to Ofgem in advance of submitting an increase in their flex bookings by more than 10 per cent per annum. We would expect that step changes in the level of flex booked by the GDNs would be mirrored by observable changes in the use of alternative capacity management options available to the GDNs on their own networks.

6.49. We acknowledge that until a decision is reached on enduring offtake reform uncertainty over the offtake arrangements which will apply from 1 October 2011 will remain. Following a request for further information from NGG Transmission on the availability of NTS exit flexibility capacity Ofgem expects to undertake further analysis of the flex capacity product. It is likely that a conclusion on enduring offtake will be reached some time in early 2008. As discussed in this section, presently we do not consider that there is sufficient information to justify implementing a flex incentive, but in the event that an enduring offtake reform proposal is implemented which provides for a market allocation of flex capacity, and/or in the event that evidence can be found for considering that a flex constraint can reasonably be expected to arise in the price control period 1 October 2011 to 31 March 2013, we accept that it would be appropriate to review this decision, and we would be prepared to open a licence modification consultation to this end if necessary.

Capex reopener

6.50. The decision we have reached on the capacity outputs incentive reflects a preference to ensure that where interruption is available on terms which make it economic for the GDNs to contract for it, the properties of the incentive make it financially efficient for them to do so. In updated proposals we listed the reasons why we consider customers will find it attractive to participate in the interruption auctions as follows: the potential for an increase in interruptible payment; more flexible contracting options; and the risk of losing out on any interruptible payments in the future if they are made firm. All other things being equal, we consider that these reasons, combined with the strong incentive on the GDNs to book interruption where it is economic for them to do so, should result in optimal levels of interruption being booked. Nevertheless, ahead of the first interruption auctions it is not possible to be certain that the GDNs will be able to contract for all of the interruption they require in all of the locations they require it. As a result in some cases network investment may be necessary.

6.51. In proposing to set the interruption incentive at the discounted cost of the level of investment required to support all existing interruptible customers as firm, we consider that, in the event that investment is required as a substitute for interruption, there will be significant scope for the GDNs to fund additional capex in the years before the next price control period through savings made against the capacity outputs incentive. However, given that differing sharing factors in the interruption incentive and the capex roller incentive could be viewed as obscuring efficient trade-offs, we consider that it would be appropriate to set out the criteria that would apply should a capex reopener be required.

6.52. Additional capex triggered as a consequence of interruption reform is likely to be driven by one of two sources: the need to remove particular locational constraints, or the need to build increased transportation or storage capacity on the GDNs to meet increased peak demand. Taking steps to remove a particular locational constraint is likely to require a one-off investment which, if NSL customers had contracted for interruption, would not have been required. The need to provide increased transportation or storage capacity is likely to require bringing forward, or in some cases upsizing, capex projects already identified through the GDPCR process. As a result of the bilateral meetings Ofgem has held with the GDNs, the GDNs' BPQ responses, and PB Power's analysis of capex, we have a clear idea of the materiality of these projects. In the event that investment is required we would expect the size and nature of the project to be known to us already.

6.53. We consider that any capex which the GDNs would like to submit for consideration under a capex reopener should meet the following criteria:

- Efficiency – The GDNs must be able to demonstrate that, taking the discounted cost of an investment over a forty five year period together with the reasonably foreseeable costs of any incremental NTS flat capacity necessary to support an increased load, interruptible offers which would have removed the need for the investment were not available in sufficient numbers or at sufficiently competitive prices to avoid the need for reinforcement. In evaluating the total interruption costs the GDNs would be likely to incur we would expect to consider both the option fee and exercise fee elements of interruption bids. We consider that it would be appropriate to look at historical patterns of interruption at an LDZ level in conjunction with future LDZ demand forecasts in evaluating the likely out turn costs associated with the exercise fee element of an interruption bid.

- Eligibility – We consider that any capex project that can be directly attributed to the outcome of the first interruptible capacity auctions scheduled for June 2008 should be eligible for consideration under the capex reopener. We do not consider that such projects will relate solely to locational network constraints and accept that in some cases the GDNs may require to invest for LTS storage capability. In the event that a storage project is considered necessary we would anticipate that GDNs will await the outcome of the NTS exit capacity booking process before approaching Ofgem with details of a capex reopener application. For the avoidance of doubt we do not consider that it would be appropriate for the capex reopener to apply on a rolling annual basis. We accept that slight movements in the contracted annual volumes of interruptible capacity are likely to be witnessed, but we consider that significant decisions over long term interruption intentions are likely to be made in the first year of interruption reform and note that the GDNs will have the opportunity to contract for up to five years of interruption at this stage.

- Marketing - In reviewing the outcome of an interruptible auction we would be likely to consider the extent to which a GDN had sought to make the interruption auction a success including the extent to which it had effectively marketed the interruptible product in determining whether investment had been necessary. In circumstances where a discrete number of customers can be considered to have triggered a particular investment we would expect that the GDNs would take steps to confirm that customers of particular interruptible value were aware of the interruption opportunities available to them in advance of the auctions taking place.

- Materiality – Any application for a capex reopener utilises time and resources from the GDNs and from Ofgem. For this reason we consider that any application should be for recovery of costs greater than £1 million per GDN. We would also expect the GDNs to take account of the effect the decision to invest would have on their performance against target in the capacity outputs incentive when reaching a decision over whether to apply for a capex reopener. In the event that an application for a capex reopener was permitted we would expect to make a proportionate adjustment to the size of the interruption and flat capacity incentive targets.

6.54. Given that the reopener has the potential to affect several terms in the allowed revenue formula, we consider that it is not appropriate to insert an income adjusting event in the licence for capex associated with interruption reform, which typically takes the form of a single adjustment to allowed revenue in a given year.

Income Adjusting Event

6.55. Ofgem considers that the IAE threshold associated with the capacity outputs incentive in the period 1 October 2011 to 31 March 2013 should take an annual value equivalent to 0.5 per cent of allowed revenue. We consider that this represents a level of protection for each GDN which is proportionate to the size of each GDN business. We intend that the IAE threshold value will be set with reference to baseline allowed revenue and so any future adjustment to overall allowed revenue arising from implementation of enduring offtake reform will not affect the basis of the calculation.

Loss of meter work revenue driver

6.56. In updated proposals, we consulted on a proposal to include in the price control settlement a revenue driver, which would provide increased revenue to GDNs to fund the increased costs of providing the emergency service, should they lose some or all of the meterwork currently performed as a supplementary work activity by emergency staff. The formula for the revenue driver is:

Allowed unit cost per job * MAX (tipping point - actual metering jobs, 0).

6.57. In the formula, the tipping point is defined as the number of jobs, below which we have forecast that the GDNs will incur additional costs. Above this level, the GDNs have identified that the work is done by staff, primarily contractors, whose time is spent entirely on meterwork.

6.58. The updated proposals calculated the tipping point primarily based on individual GDN forecasts of the point at which they would start to incur incremental costs, but then averaged (as a proportion of 2005-06 jobs) with the GDN average, to reduce the wide range of forecasts.

6.59. As the GDNs lose meterwork, the emergency service staff will start to have unproductive time which would currently be used to attend metering jobs. This will result in a higher proportion of the time of those staff being chargeable to the transportation business. The updated proposals provided an allowance for this, based on the additional number of FTEs that would be required to cover the average GDN forecast additional waiting time. Where this was different to the GDN forecast for additional FTEs, the cost within updated proposals was based on the average of the two.

6.60. The unit cost was then calculated as the average incremental cost per job beyond the tipping point, i.e. :

(Additional FTEs to provide emergency service)*(benchmark cost per FTE) divided by the tipping point.

Respondents' views

6.61. All GDNs supported the principle of a revenue driver. All GDNs also pointed out that the revenue driver was providing lower cost allowances than they had forecast would arise as a result of the loss of meterwork. All other responses supported the principle of a revenue driver, as long as sufficient justification was given for the additional costs.

6.62. NGG and WWU argued that the allowance was lower than their forecast as a result of an inconsistent methodology being applied. Specifically, the proposal within updated proposals for unit costs was based on the use of increased waiting time to establish the impact on the number of FTEs required to perform the emergency service. These GDNs argued that while this is a proxy for the increase in costs, it is not the best driver. Instead they argued that there is a minimum number of staff who are required for each LDZ to provide an emergency service, regardless of the level of meterwork. These GDNs argued that the allowance should reflect the cost of providing the emergency service using this number of FCOs, and assuming no meterwork.

6.63. All GDNs' responses focussed on the high-level difference between Ofgem's allowance and their forecasts for the increased costs, and suggested an increase in unit costs was required.

6.64. NGG and SGN also argued that allowance should be made for reallocation of overhead costs to the transportation business.

6.65. Non-GDNs were also generally supportive but concerns were raised that the mechanism should be subject to monitoring, and justification should be provided before any increases in revenue are permitted.

Ofgem's decision

6.66. We have considered the argument that the approach of assuming a consistent increase in waiting time for each GDN, while providing a method of estimating a consistent increase in costs across GDNs, may not reflect the different impacts on GDNs of the loss of meterwork. Some GDNs require a higher level of emergency staff per emergency job due to sparsity or congestion. These factors will not be reflected if a benchmark or average increase in waiting time is used to derive the revenue driver.

6.67. We have reviewed the additional detail provided by NGG and WWU. We conclude that the level of detail supporting their analysis is sufficient to demonstrate that the number of incremental staff they have identified to be required for the emergency service, if the meterwork is lost according to their forecast, is broadly consistent with the shape and size of their networks. As part of a balanced approach to compensating the GDNs for the direct impact of the loss of meterwork, we have decided to amend the approach to calculating the additional FTEs to reflect each GDN’s forecasts of the incremental emergency staff, allocated over the total metering jobs to be lost.

6.68. As a result, we have decided to set a cost allowance based on the number of incremental FTEs whose costs are to be charged to the emergency service, by comparison with 2006-07 actual FTEs. As a result, even if all meterwork is lost, the GDNs will receive sufficient allowances to cover the cost of providing the emergency service, subject to meeting the targets for new supplementary work activity.

6.69. Using this approach, the tipping point is equal to the level of jobs above which the workload is covered by specialist metering personnel. This is calculated as:

Current metering jobs - ((2006-07 FTEs - minimum FTEs) * Metering jobs per FTE)

6.70. We have also reviewed whether we should include an assumption of other supplementary work activity, and whether we should include an allowance for indirect costs.

6.71. We have concluded that a small assumption of supplementary work activity is appropriate, but that this can be phased over the five years to give sufficient time for the GDNs to develop a response. We have assumed zero per cent supplementary work activity in 2008-09, 5 per cent in 2009-10, rising to 20 per cent in 2012-13.

6.72. We have also considered whether we should provide an allowance for indirect costs. We do not consider that this would be consistent with our approach to setting allowances for the regulated business. If there is a genuine reduction in the extent of the business undertaken by the regulated entity, some reduction in indirect costs will follow. Alternatively, some GDNs may pursue comparable work outside of the regulated business. We have provided a small adjustment for work management to most GDNs based on a comparison of GDN forecasts.

6.73. Table 6.5 demonstrates the impact of this approach on the unit cost and tipping point for each GDN. The unit costs for 2008-09 assume zero additional supplementary work, which will result in a reduction in unit cost of 5 per cent per annum with effect from 2009-10. An increase in tipping point implies that the unit costs will apply to a greater number of metering jobs, and therefore reflects a potential increase in allowed revenue.

Table 6.5 - Comparison of unit costs and tipping points

	Tipping point (UP)	Tipping Point (FP)	Unit cost £ (UP)	Unit cost £ (FP) 2008-09	Unit cost £ (FP) 2012-13
East of England	204,762	225,512	26.5	30.8	24.6
London	100,511	124,540	30.5	33.0	26.4
North West	106,252	91,040	31.4	29.8	23.9
West Midlands	106,306	161,388	29.5	27.1	21.7
Northern	166,615	118,753	21.6	38.6	30.9
Scotland	214,795	183,696	11.6	17.6	14.1
Southern	305,614	369,657	19.1	25.0	20.0
Wales and West	147,471	246,060	21.7	23.4	18.7

6.74. The potential cost to customers, if the GDNs lose meterwork as forecast is an average of £24.1 million per annum over the price control (compared to £18.5 million at updated proposals), or 0.3 per cent increase in average X.

6.75. This reflects a reduction of around 35 per cent on GDNs' forecasts of the impact on direct costs by 2012-13. This differential reflects the impact of our target of finding 20 per cent supplementary work for the emergency staff by 2012-13, lower allocation of overheads, and the benchmarking of costs per FTE.

6.76. In summary, to balance Ofgem's duties to customers with the duties to ensure GDNs can finance their activities, the revenue driver needs, both to provide sufficient funding to deliver the emergency service, and also to encourage GDNs to innovate and find new streams of work that their emergency teams can undertake when not required for emergency work. We recognise that there are risks that changes in the metering market may make it more difficult for GDNs to continue to provide metering services but want to provide them with strong incentives to explore with suppliers whether they can still provide some metering services or whether they can use the skilled staff to deliver and support other new initiatives. We believe that the package described above is consistent with those aims.

Monitoring of the revenue driver

6.77. The revenue driver is intended to compensate GDNs for losses in metering jobs in the metering business in its current form and to provide incentives to innovate and find new types of work for emergency service staff when they are not required for emergency work. However, a "metering job" can cover up to 30-40 different chargeable activities, with different resource requirements. The unit cost reflects an average incremental cost if those jobs are lost evenly.

6.78. As part of the cost reporting framework, the GDNs will be required to provide confirmation both of how they have calculated the number of metering jobs used when assessing the value of their allowance under the revenue driver, and also that they have not had a substantial change in the nature of the metering business.

6.79. If, for example, the metering business performed by the emergency staff had changed substantially to reflect a different average size of meterwork job, then the unit costs in the table above would no longer be commensurate with the impact on the costs of providing the emergency service for that GDN. If this resulted in a windfall gain for a GDN, Ofgem would then seek to adjust the impact of the revenue driver on that GDN to reflect the revised form of the metering business. In particular, this would be intended to cover any deliberate actions on the part of the GDNs to restructure the metering contracts to maximise the benefits of the revenue driver.

7. Sustainable development

Chapter Summary

This chapter discusses our final proposals in a number of areas related to sustainable development, including gas shrinkage and environmental emissions incentives, discretionary reward scheme, network extensions and innovation funding incentive.

Shrinkage

7.1. Gas shrinkage is gas lost from the network through leakage, theft and own use gas. In the one year control we provided a revenue allowance for shrinkage based on ex ante target shrinkage factors (percentages of throughput) and a gas reference price related to three month ahead gas futures prices. This was a change from the previous price control where GDNs' allowances were set including a fixed assumption about the wholesale price of gas. In the early years of the previous price control, gas prices were marginally lower than the assumed price, allowing for outperformance, but in the latter years, gas prices exceeded the assumed price by a large margin, so that the GDNs under-recovered by material amounts. By indexing the allowance to an appropriate gas reference price, we substantially lowered the GDNs' risk profile.

7.2. Due to the difficulties the GDNs would have in exactly matching the price index, because the variations in their purchase requirements arising from fluctuations in throughput mean that they have to buy or sell gas at less favourable prices, we included a 3.5 per cent uplift. For the main price control we have proposed to continue with a reference price mechanism that protects the GDNs from price fluctuations over which they have no control, but have sought ways to reduce or remove the need for an uplift. In updated proposals we proposed setting a fixed volume allowance for gas leakage and shrinkage factors (percentage of demand) for own use gas and theft. We proposed setting the gas reference price as the day ahead price with no uplift.

7.3. On 24 October we issued an open letter revising our proposed shrinkage volumes following receipt of updated information from the GDNs. In the open letter we proposed setting a fixed volume allowance for all elements of shrinkage.

7.4. In updated proposals and in the open letter we sought views on whether to roll forward the reference price mechanism, whether the allowances should continue to be related to demand and how the gas reference price should be set.

Respondents' views

7.5. Most respondents supported a fixed volume allowance, not related to throughput, with a gas reference price linked to day ahead or on the day prices. One respondent did not support a fixed volume allowance stating that insufficient supporting evidence had been provided and suggested that non daily metered customers would bear an increased level of risk.

7.6. One respondent considered that only the leakage element of the shrinkage allowance should be a fixed volume and that the own use gas and theft allowances should be linked to demand. Another respondent considered that GDNs should meter their own use gas and one suggested that GDNs should report and account for gas escapes caused by third party damage.

7.7. NGG considered that its allowance should exactly reflect its submission based on data provided prior to correcting for an error in the leakage model related to leakage from pit cast mains. NGG supported the proposal to allow a fixed volume for own use gas and theft, independent of demand.

7.8. NGN supported the removal of the link between shrinkage and demand. NGN has proposed an uplift over the gas price of between 1.2 and 1.8 per cent to take into account gas purchase transaction costs.

7.9. SGN considered that the rate of reduction proposed for its networks was too aggressive and that it should be changed to the average rate proposed for other networks. SGN considered that recent shrinkage levels were unusually low due to low seasonal normal temperatures.

7.10. WWU proposed increasing the volume allowances set out in the open letter to take into account changes to reported leakage caused by data cleansing and removal of pressure control systems from some of its networks. WWU supported the use of a fixed volume allowance for own use gas and theft.

Ofgem's decision

7.11. We have considered respondents' views and held discussions with stakeholders regarding the shrinkage allowances.

7.12. The evidence available shows that there is little correlation between shrinkage and throughput for the existing networks. Theory suggests that where pressure control is not applied there will be an inverse correlation between leakage and throughput, i.e. leakage will reduce as throughput increases and where highly effective pressure control is applied the correlation becomes positive but - not proportional. The GDNs have provided information suggesting that in networks with a high degree of pressure control a positive correlation can be expected such that where demand increases by 1 per cent, leakage would increase by circa 0.3 percent. With the introduction of the environmental incentive discussed below, we anticipate that the GDNs will install additional pressure control equipment and improve management focus on the operation of existing equipment. This suggests that, as pressure control is more effectively applied, some correlation may be expected in future years and that this will be related to an overall reduction in leakage volumes.

We do not accept that there is currently a measurable correlation between leakage and throughput.

7.13. SGN suggested that historical leakage from its networks was low in 2006-07 due to atypically warm weather and was expected to increase during "normal" weather. We consider that the level of leakage achieved for 2006-07 is a robust starting point for our projections of future leakage. SGN also suggested that the rate of reduction of leakage was too aggressive and that it should be allowed the average rate of decline. We are proposing a higher level of capital expenditure for SGN specifically related to maintaining system pressures than for other networks and expect a more rapid reduction in leakage from SGN's networks. We propose to use the rate of reduction in leakage derived from data from the leakage model as provided by SGN in determining the allowed leakage volume.

7.14. WWU indicated that data cleansing had affected historical reported leakage with significant asset transfers between Wales North and Wales South. WWU considered that leakage in its networks had increased because pressure control equipment had been removed. It is questionable whether removal of the old equipment was efficient and we do not consider it is appropriate to increase baselines to take account of increased leakage caused by this action. We do not accept that overall leakage in WWU's networks will be affected by the transfer of assets between its LDZs.

7.15. Own use gas and theft represent a relatively small proportion of total shrinkage and variations in quantities are not sufficiently material to justify the additional complexity of retaining a volume driver for these elements.

7.16. We do not consider the increase in risk for non daily metered customers caused by changing the shrinkage allowance from a percentage of demand to a fixed volume to be significant. Given that the fixed volume more accurately represents actual leakage, the change to a fixed volume allowance will be more cost reflective.

7.17. We have no evidence to suggest that metering own use gas would result in overall cost savings to consumers. It would only be useful if all own use gas was metered and the cost of metering seems likely to outweigh the benefits of the forecast reduction in gas consumption.

7.18. GDN reporting of leakage caused by third party damage would appear to have some merit. Leakage reporting is covered by existing UNC arrangements. The industry could propose changes if, following discussion with stakeholders, additional reporting was considered appropriate.

7.19. We propose setting a fixed volumetric allowance for shrinkage for each LDZ as set out in table 7.1. In order to allow time for these modification proposals to be considered, and avoid potentially significant windfall gains or losses, we propose to roll over the existing shrinkage allowances (both volume and price) for the first six months of the next price control period. We have updated the allowed shrinkage factors (expressed as a percentage of throughput) to reflect each GDN’s final proposals to the shrinkage forum for the gas year 1 October 2007 to 30 September 2008.

Table 7.1 - Shrinkage allowances

		Shrinkage factor	Shrinkage volume (GWh)				
		2008-09*	2008-09*	2009-10	2010-11	2011-12	2012-13
Owner	LDZ	Total	Total	Total	Total	Total	Total
NGG	East Anglia	0.616%	145	286	286	286	285
	East Midlands	0.510%	208	409	409	408	406
	North Thames	0.546%	201	396	393	390	386
	North West	0.627%	261	501	488	484	480
	West Midlands	0.727%	210	403	393	391	388
NGN	Yorkshire	0.638%	151	296	292	288	283
	Northern	0.584%	120	234	230	227	224
SGN	Scotland	0.458%	148	284	278	272	266
	South East	0.648%	232	445	433	421	409
	Southern	0.698%	156	303	298	292	286
WWU	Wales North	0.796%	34	64	61	60	59
	Wales South	0.563%	88	170	163	157	153
	South West	0.886%	155	299	292	285	278
Total			**2,108**	**4,090**	**4,016**	**3,960**	**3,904**

* For 2008-09, the factors will apply for the first six months. Since these are a percentage of throughput, they do not need pro-rating. For the second six months, we have taken the annualised expected leakage volume and multiplied it by 182/365, reflecting our assessment that there is no clear relationship with throughput. For the other components of leakage, which have been derived from a throughput-based factor we have taken 65 per cent of the annual total to reflect the weighting of throughput in the winter period.

7.20. We propose setting the gas reference price as the day ahead price from 1 October 2008, as published by a reputable market index information provider. This effectively allows GDNs to avoid all material price risk if they choose by simply buying at the index. This eliminates the need for an uplift factor and reducing prices paid by customers. We accept that there may be some small additional cost incurred in procuring gas at the index price but given the level of materiality we do not consider it is appropriate to provide an explicit allowance for this.

7.21. The volume of shrinkage gas purchased by the GDNs is determined by the UNC. The GDNs have indicated that they intend to propose modifications to UNC to align their responsibility for procuring gas to the actual gas used by the GDNs. They consider that the current rules for calculating shrinkage under the UNC do not accurately reflect actual shrinkage and the volumes calculated under the UNC will differ significantly from their proposed price control volume allowances.

Environmental emissions incentive

7.22. Gas leaking from the distribution networks is a significant source of greenhouse gas emissions representing circa 0.75 per cent of GB emissions. The GDNs are already reducing leakage for safety reasons through investment in the mains replacement programme. However, we consider that there may be additional initiatives that the GDNs could undertake to reduce leakage if they faced the social cost of carbon contained in leaked natural gas.

7.23. In updated proposals we proposed an environmental emissions incentive that would expose GDNs to a price that more accurately reflects the potential damage and costs associated with carbon emissions. We considered that at this time the most appropriate value to use was DEFRA's shadow price of carbon[21]. The incentive was based on setting target leakage baselines in line with the GDNs' forecast rate of mains replacement and system pressures. If a GDN achieves lower leakage than its baseline they will be rewarded for the marginal social benefits, and if their leakage is higher they will be penalised at the same rate. We proposed setting leakage baselines for each LDZ with an average incentive strength (in 2005-06 prices) of £29.70 per MWh over the price control period (based on Defra's figure of £25.40 in 2007 prices increasing in real terms by 2 percent per annum). Since this is the first time we have set such an incentive, we consider there is a risk of windfall gains or losses, and so it is appropriate to have caps and collars on the incentive. We proposed aggregate incentive caps and collars of £7 million to £10 million for all LDZs.

7.24. Following publication of updated proposals, we issued an open letter on 24 October revising our proposed emissions incentive baselines following receipt of updated information from the GDNs. In updated proposals and in the open letter we sought views on whether to introduce a new environmental incentive to reduce emissions from the gas distribution networks, the form of the incentive, incentive baselines, incentive strength, caps and collars, and whether to introduce a rolling mechanism to address investment periodicity.

Respondents' views

7.25. Responses on levels of leakage and baselines were identical to those for shrinkage as discussed above. All the GDNs proposed higher baselines.

7.26. NGG and SGN supported using a fixed CV for reporting shrinkage.

7.27. SGN supported the introduction of a rolling incentive mechanism. SGN suggested that changes to the leakage model should produce a commensurate change to baselines.

Ofgem's decision

7.28. We propose to set baselines as set out in table 7.2 below. These are identical to the leakage element of the shrinkage volumes discussed above.

[21] http://www.defra.gov.uk/environment/climatechange/research/carboncost/index.htm

Table 7.2 - Environmental emissions baselines

Environmental emissions baseline (GWh)						
		2008-09	2009-10	2010-11	2011-12	2012-13
Owner	LDZ	Total	Total	Total	Total	Total
	East Anglia	271	270	269	268	267
	East Midlands	384	383	382	380	378
	North Thames	375	374	371	368	364
	North West	488	473	460	455	450
NGG	West Midlands	396	385	374	371	367
	Yorkshire	284	280	276	271	265
NGN	Northern	224	220	217	213	210
	Scotland	270	264	258	252	245
	South East	433	421	409	396	383
SGN	Southern	294	288	282	276	270
	Wales North	64	61	58	57	56
	Wales South	164	160	153	147	142
WWU	South West	296	286	279	272	265
Total		**3,943**	**3,867**	**3,788**	**3,726**	**3,664**

7.29. We propose to introduce governance arrangements specifying how leakage is reported and to ensure that material changes to reporting arrangements are approved by the Authority. We propose to introduce governance arrangements such that when the leakage model is changed commensurate changes to the baselines are considered concurrently. We propose to allow the GDNs to report environmental emissions for the purpose of this incentive assuming a constant CV.

7.30. We propose setting the incentive strength in year one at £28.50 per MWh (2005-06 prices) increasing by 2 per cent per annum plus inflation. This results in an average incentive strength of £29.70 per MWh over the price control period. The annual incentive values are shown in table 7.3 below.

Table 7.3 Environmental emissions incentive values (£/MWh)

Shadow price of carbon (£ per MWh)				
2008-09	2009-10	2010-11	2011-12	2012-13
28.50	29.07	29.65	30.24	30.85

7.31. We propose to introduce symmetrical caps and collars at 10 per cent of the baselines. These will have a maximum monetary value of a little over £11m for each year of the incentive. This is marginally higher than the top end of the range of £7-£10m on which we consulted in updated proposals, but as the difference represents less than 0.05 per cent of allowed revenue we consider that the limits remain appropriate.

7.32. One GDN considered that a rolling incentive would maximise the benefits from the environmental incentive. We agree that there are potentially merits in introducing a rolling incentive to address periodicity of investment but this is a new incentive with the attendant greater uncertainty as to the GDNs' abilities to outperform the targets. We do not wish at this stage to magnify the benefits of outperformance or the penalties for underperformance further. We do not intend to introduce a rolling incentive in this price control.

Discretionary reward scheme

7.33. In initial proposals, we considered it appropriate to introduce a Discretionary Reward Scheme (DRS) similar to the electricity distribution customer reward scheme introduced as part of DPCR4. The scheme in electricity distribution has been positively received as companies have responded appropriately and we have been able to implement it at little cost.

7.34. The scheme will have a total annual reward of £4 million available across all the GDNs (£20 million across the price control period), and the categories are:

- initiatives which reduce the environmental impact of gas distribution including those that reduce shrinkage but which may not be rewarded through the shrinkage incentive and those that improve the measurement of shrinkage;
- initiatives which facilitate network extensions, particularly those that increase the affordability of network extensions for fuel poor consumers; and
- schemes to promote gas safety including awareness of carbon monoxide (CO).

7.35. The reward may be awarded annually to one or more GDNs or not at all. Where a reward is made under the scheme, the amount of that reward will be recovered from the GDNs' consumers; i.e. a GDN who provides better service will be able to charge marginally higher transportation charges to its consumers. Should no GDN receive a reward under the scheme, there will be no financial impact on consumers. The reward amount available under this scheme is not intended to fund GDNs' initiatives but to provide an additional incentive to GDNs to better serve their consumers in these areas.

7.36. Consistent with the DNO scheme, GDNs will be required to complete and submit an application detailing why they should receive a reward under the scheme. Applications will be reviewed by a multi-disciplinary panel who will make recommendations to the Authority as to who should receive a reward and why.

7.37. The focus of the scheme and the weighting of the reward across the categories will be decided by Ofgem, in conjunction with the panel, at the start of each year. The rewards will then be decided in the following May and will feed into revenue allowances on 2-year lagged basis (i.e. 2008-09 reward will feed into revenue in 2010-11.

Respondents' views

7.38. Overall, the GDNs supported our proposals to introduce a DRS.

7.39. The majority of non-GDN respondents supported a DRS but expressed some concerns. Energywatch considers that the recovery of the reward from consumers must be weighed against any long-term consumer benefits. Two non-GDNs consider that priority should be given to promoting network extensions within the DRS. One respondent is not fully convinced of the need for GDNs to have a DRS as areas being covered for reward are covered by specific initiatives and incentives. Another non-GDN considers a DRS sensible and consistent with other price controls, however as it stands, it does not provide sufficient incentives to drive appropriate behaviours. Finally, one respondent said £4 million is not adequate, and considers that gas safety should be given the majority of the reward.

Ofgem's decision

7.40. We continue to hold the view that it is appropriate to introduce a DRS for GDNs. The scheme has been positively received in electricity distribution, companies have responded appropriately and we have been able to implement it at little cost. Implementing a similar scheme for GDNs will encourage and drive performance in areas that cannot be incentivised through more mechanistic regimes. It will also result in further benefits for consumers through enhanced comparative competition, as GDNs' initiatives and their relative success will be assessed under the scheme.

7.41. We also consider that the scheme categories, format and value as set out in initial proposals and repeated above remain appropriate. We note that although we intend to set out the weightings of each category at the beginning of each year, this is flexible and depends on submissions.

7.42. As part of the price control package there will be incentives on GDNs to reduce shrinkage and environmental emissions. We will be careful to ensure that GDNs are not rewarded twice for initiatives related to shrinkage.

Network extensions

7.43. As part of the initial proposals document, we published an impact assessment on facilitating network extensions in which we proposed to implement a change to the GDNs' charging arrangements complemented by the discretionary reward scheme. The change to the charging arrangements consists of amending the Economic Test when it is applied to non-gas fuel poor communities, so that GDNs offer a discount to the connection charge equivalent to the present value of the transportation revenue that it will receive from the new customer.

7.44. In updated proposals, we confirmed our initial proposals for network extensions.

Respondents' views

7.45. Responses to our initial proposals were generally positive, although some issues were raised over the detail[22].

Ofgem's decision

7.46. We continue to consider our proposals on network extensions to be appropriate as confirmed in updated proposals.

7.47. To give effect to our proposals, we expect GDNs to come forward with proposals to amend their existing connection charging methodology statements under standard licence condition 4B. These proposals should cover how the economic test will be amended and which communities this amendment will apply to, as well as address any competition issues.

7.48. To identify which non-gas communities will be eligible to receive special treatment, the Government's Index of Multiple Deprivation (IMD) will be used based on a target percentage of the 20 per cent most deprived areas.

7.49. The net capex derived from the economic test allowance, that will offset the connection charge to a community, will be capitalised and added to the GDN's RAV at the subsequent price control. The capital charges incurred over the price control will be recovered on an NPV-neutral basis as part of the subsequent price control allowance. We expect this net capex figure to be based around the actual uptake rate within the community but further detail will be outlined in the GDNs' charging methodologies.

7.50. In the event that GDNs do not bring forward charging methodology changes as discussed, Ofgem will consider carefully what action it can take.

Innovation funding incentive for sustainable development

7.51. In the updated proposals, we set out our intention to introduce an Innovation Funding Incentive for Sustainable Development (IFI/SD), and we included an impact assessment.

7.52. We proposed that the scheme will be modelled on the scheme already in place for electricity distribution to provide special focus for Research, Development & Demonstration (R,D&D) activities. These activities should be targeted to deliver

[22] See Appendix 5 of the GDPCR Initial Proposals Main Supplementary Appendices, May 2007 (Ref. 125a/07) for the summary of responses and Ofgem's views.

environmental and sustainability benefits, through alignment with Ofgem's five published sustainable development themes[23].

7.53. The IFI/SD framework will make available ring-fenced funding for innovation projects of a technical nature that conform with industry guidelines for good practice as set out an approved Good Practice Guide (GPG).

7.54. The IFI/SD framework will ring-fence funding equal to 0.5 per cent of allowed revenue annually. GDNs may pass 80 per cent of the cost of each innovation project to customers up to this limit. They are required to fund the remaining 20 per cent of each project themselves with a pass through of 80 per cent throughout the price control period. Thus the maximum adjustment to allowed revenue is 0.4 per cent of allowed revenue per annum. With regards to the amount of eligible IFI expenditure that can be used to fund internal contributions, we are proposing to adopt a maximum level of 15 per cent for the time being. This will be kept under review as operational experience is gained.

7.55. Following the practice established for the DNO IFI scheme, we proposed a partial carry over of up to 50 per cent of unspent eligible IFI expenditure from one year to the next. We did not propose a cumulative carry over.

7.56. The GDNs will be required to report on IFI/SD projects in accordance with regulatory instructions and guidance (RIGs) and a GPG. We proposed that the GPG should be developed by the GDNs, following the principles established in Energy Networks Association Engineering Recommendation G85 for the existing IFI schemes, and approved by Ofgem. The ENA has indicated that it is willing to be custodian of this IFI/SD document.

Respondents' views

7.57. Our proposals for the IFI/SD scheme have been well received. One respondent encouraged Ofgem to allow the scheme to have as wide a remit as possible and considered there should be active promotion, monitoring and audit of the scheme. Another respondent supported efforts to reward investment in R&D in the sector and would like to see financial support for contractor led R&D.

[23] Ofgem's SD themes and explanatory background can be found in our SD Report 2006 at www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Sustainability
The headline themes are:
1. Managing the transition to a low carbon economy
2. Eradicating fuel poverty and protecting vulnerable customers
3. Promoting energy saving
4. Ensuring a secure and reliable gas and electricity supply
5. Supporting improvement in all aspects of the environment.

Ofgem's decision

7.58. We have decided to introduce an IFI/SD scheme to this price control, in line with the updated proposals, including the reporting requirements and the development of a GPG.

7.59. We consider that even though the scheme is focussed on sustainable development this gives it a suitably wide remit for the types of projects that will qualify, including projects that combat climate change, promote other environmental benefits, enhance the strategic asset management of critical national infrastructure and improve safety in the industry and in homes (for example, through research into CO safety issues).

8. Other issues

Chapter Summary

This chapter includes other issues that make up the price control arrangements. It includes our final proposals on the funding of xoserve and arrangements for independent systems following the recent decision by the Department for Business, Enterprise and Regulatory Reform.

Funding of xoserve

8.1. The concept of a transporter agency was an important aspect of the industry restructuring that occurred as part of GDN sales. The purpose of the agency was to provide a common system and service interface between the multiple network transporters and the industry, mainly the shippers and suppliers, to mitigate cost and competition impacts following the sale. xoserve currently fulfils the agency role and it is responsible for a variety of functions such as invoicing shippers for use of the transportation system, and managing the change of supplier process.

8.2. xoserve currently provides services on behalf of the GDNs and NGG NTS in accordance with the terms of the Agency Services Agreement (ASA).[24] The ASA details the services to be provided by xoserve and the service standards to be achieved. It also sets out the arrangements by which xoserve charges GTs for its services. GTs pay these charges using price controlled revenue.[25]

8.3. As part of the GDPCR we recognised that the current funding model may provide poor incentives both on the GTs to provide anything more than a minimum level of service and on users (primarily shippers and suppliers) to manage xoserve's costs. We noted that there were a wide range of funding options possible but, through early consultation, identified that there was little industry appetite for any significant change such a short time after GDN sales.

Core services plus user pays

8.4. We propose to change the funding arrangements for xoserve to improve the incentives for GTs to be proactive with users in the services they offer via xoserve and to encourage users to consider more carefully the costs they impose.

8.5. It is proposed to introduce a core services plus user pays approach. Under this approach, regulated services provided by xoserve would be classified as one of:

[24] The Agency Services Agreement is available on the Joint Office website. See http://www.gasgovernance.com/Publications/Misc/.
[25] The current price control includes an allowance for Transco plc's "shipper services" which reflects the industry structure in place at the time the control was set.

- *Core services.* Regulated services that it is appropriate to fund using price control allowed revenues. The costs associated with these services are spread across all customers through gas transportation charges.
- *User pays services.* Regulated services that it is appropriate to fund using charges levied directly upon the user(s) requesting the service. For the purposes of the price control, such services would be excluded services[26].

8.6. We consider that this funding arrangement will have the following benefits:

- GDNs and NGG NTS (xoserve) would have an incentive to enter into dialogue with users to provide additional services and respond to their needs due to the opportunity to earn additional revenue above their costs;
- it gives users an incentive to manage the costs they impose on xoserve because they would pay for the additional services they request / use; and
- xoserve's cost forecasts include a significant amount of expenditure on an upgrade of UK-Link. User pays would help to make sure that the incremental capacity of these new systems is given to those who value it most.

8.7. An industry working group in conjunction with the gas transporters and xoserve have considered the existing services provided by xoserve and identified a number of services which are candidate user pays services. These are:

- provision of information;
- reporting;
- user admission;
- must reads;
- AQ amendments & appeals; and
- shipper agreed reads.

8.8. For the purposes of the price control, the costs associated with these service lines are netted off the revenue allowances proposed for the GDNs and NGG NTS in proportion to their individual share of xoserve's costs. Income from these user pays services will be treated as excluded services for the price control period.

8.9. User pays services are expected to increase during the price control period in two main areas. Firstly, user(s) requesting new services from xoserve either in the form of additional services or as enhancements to existing services, such as a quicker response on an existing service. In the main these are unlikely to impact on other users and would be expected to be contracted on a bilateral basis. Secondly, there will be changes that users wish to make to existing services which do impact on other users as they change the way the service is provided for a number of users or market segment. These changes are likely to be through amendments to the Uniform Network Code (UNC). This is discussed further below. In both cases these areas will be considered to be excluded service income. GDNs will be required to

[26] While we would expect xoserve to invoice shippers for these services, they would do so on behalf of GTs.

report on all user pays services through the cost and revenue reporting packs. These arrangements are detailed diagrammatically below:

Core Services	▪ Existing services provided by xoserve funded through GT charges. ▪ Detailed in UNC. ▪ Includes UK Link replacement as scoped by xoserve.	Total forecast cost of xoserve
User pays for 6 high level services lines identified	▪ Existing services provided by xoserve now funded through user pays charges. ▪ Contracted bilaterally and through UNC.	
User pays bilateral arrangements between xoserve and shipper	▪ New services requested from user(s), e.g. additional or higher service level. ▪ Don't impact on other users directly.	Future services
User pays for UNC modifications	▪ Includes minor and major industry change, e.g. smart metering. ▪ Any incremental cost funded by charges to users. ▪ Any significant change on an exceptional basis funded through GT charges.	

Governance

8.10. For this revised funding arrangement to be effective in promoting the introduction of services between price control reviews, the parties need to be able to agree how much the service should cost, and who should bear the cost associated with the service. In particular, there need to be contractual arrangements to support these services.

8.11. GDPCR is concerned with the price control arrangements for the funding of xoserve. The governance arrangements that support user-pays are relevant. It is important that the price control and commercial arrangements line up, but they are not part of the price control. Following initial proposals, an industry group was established through the joint office of gas transporters to develop the required governance arrangements and established a work programme to take this forward.

8.12. This work is on-going but is focussed on developing the necessary changes or new arrangements. It is expected that this will include changes to the UNC, developing a joint transporter charging statement, and invoicing and contractual arrangements. We will work with this group to deliver the governance framework. In general, we expect that core services would remain within the UNC and user pays services would be through separate contract negotiated on a bilateral basis or included within the UNC.

8.13. We are proposing licence amendments (modifying standard special licence condition SSC A15, Agency) to ensure that the scope of core services and user pays determined as part of the price control are equivalent to those that the GDNs and NGG NTS through xoserve actually charge to ensure there is no gap or double counting. This will include the need for a common transporter charging methodology covering the user pays services and detailing the basis of user pays services. Some user pays services may be agreed between xoserve and the user. Given that xoserve is a monopoly service provider whose primary role is to support and facilitate the market we would expect them to offer the same services to all parties at the same price. We expect xoserve to publish the principles of how they determine the costs of providing a service and the nature of the services they offer (and the prices paid) whether offered bilaterally or multilaterally in their charging methodology and charging principles.

Industry change

8.14. As noted above, user pays services are expected to develop over the price control period from the limited number of existing service lines already identified. These are expected to be new services or upgrades or variations to existing service lines requested by individual users or group of users. In this situation it is expected that these arrangements would be contracted on a bilateral basis. However, there will be minor and potentially major changes proposed by users that set out to alter existing core services. These services are detailed within the UNC and a UNC modification would be necessary to change the service. In this case the change is likely to impact on a number of parties and the funding of the change will need to be decided. In general, we would expect those parties who are beneficiaries of the modification, particularly those who make greatest use of the service and place greatest value on it, to bear the costs. If they were a transporter we would expect them to bear the costs indirectly as the shareholders of xoserve and if they were a shipper we would expect them to bear the costs through user pays charges levied directly by xoserve. We expect the industry group to develop the necessary governance in this area.

8.15. xoserve has been funded for their existing services including the replacement of UK Link on a like-for-like basis and therefore any change that rewrites their obligations will affect the level of costs they incur, both up and down. We would not expect xoserve to charge more to users than the incremental cost of the change in this circumstance.

8.16. It is recognised that the replacement of UK Link towards the end of the price control period provides a cost effective opportunity for the industry to rationalise and put in place revised systems that are fit for purpose. It is expected that xoserve will be consulting with industry during 2008 on the potential scope and design for the new systems. This will provide opportunities to consider future user driven developments, such as changes required due to smart metering. There may also be opportunities for IGTs to consider their existing systems and where appropriate utilise a common industry platform. Given this replacement any additional capital costs generated by potential UNC changes are likely to be mitigated to an extent.

Independent systems

8.17. Independent systems are small gas networks serving communities that are not connected to the main gas transportation system. They are supplied by lorries or boats carrying natural gas in liquefied form, or with propane. Independent systems are more costly to operate than the main gas distribution network. A series of determinations issued by the Secretary of State provided the GDNs and NGG NTS with approval for a set of suitable alternative arrangements to protect the interests of consumers connected to independent systems operated by them[27]. The large majority of these networks are in Scotland[28].

8.18. The alternative arrangements are currently given effect through a set of legal undertakings which are due to expire on the 31 March 2008. The Department for Business, Enterprise and Regulatory Reform (BERR) considered that the current arrangements should continue and published a consultation document at the beginning of August 2007 on this question, and the form that any future arrangements might take.

8.19. At the end of November BERR published its decision document which concluded that the arrangements should continue in a similar form and asked Ofgem to consider how these arrangements should be given effect. Further information can be found in BERR's decision document[29]. In their decision, BERR recommended a number of changes to the form of the current arrangements.

8.20. Firstly, it proposed to cap the transportation charge cross-subsidy to the local GDN equivalent transportation charge rather than the average GB transportation

[27] Set out in 'National Grid Transco - Potential sale of Gas Distribution Networks: Statement of Reasons Following the Secretary of State's Decision', February 2005. See www.dti.gov.uk/energy/index.html
[28] In addition, small independent systems are located in Wales and North England.
[29] BERR response document: "Proposal to continue cross-subsidy arrangements for independent systems"
http://www.berr.gov.uk/consultations/closedwithresponse/index.html

charge. BERR argued that this would remove a potential perversity whereby the GB average transportation charge could be less than the host distribution network with the effect that the consumers on the independent system would pay a charge held down by subsidies to a lower level than that paid by their regional neighbours supplied from the same network operator. BERR's proposal to change the transportation cross subsidy ensures that consumers on an independent system pay an equivalent charge to consumers on the main gas networks served by the same GDN. On this basis we propose to modify the relevant GDN licences to ensure they comply with this requirement.

8.21. Secondly, BERR noted arguments from responses that there were additional costs to serve independent systems that were not currently being subsidised on a GB basis but rather were being subsidised from customers within the GDN. BERR considered that to the extent these costs were associated with the additional costs of serving independent systems they should be subsidised on a GB basis. We note that there are additional costs incurred by SGN for the Scotland GDN, NGN and WWU in serving the independent systems within their region. In line with BERR's decision these costs will now be recovered from all GB consumers in the same way as the bulk price differential, i.e. through the NGG NTS charges. It is proposed to modify the NTS licence to enable them to recover the agreed efficient level of costs from consumers and pass this income through to the relevant GDN.

8.22. We propose to implement the arrangements through licence modifications. The detail will be provided through our proposed second licence drafting consultation that we intend to publish in December 2007. This will provide an opportunity for stakeholders to comment on the proposed detail of the arrangements in advance of the statutory consultation in February 2008.

8.23. Lastly we note, in responses to our recent consultation on LNG storage price control initial thoughts[30], SGN argued that, given the use it makes of the Glenmavis LNG storage facility in supplying customers on its independent systems and the lack of control over the costs, it should have a pass through in its own price control for these costs. The prices that SGN currently pay are regulated by a price cap although this approach is being consulted on by Ofgem as we assess the potential for future competition in the LNG storage market. SGN acknowledges that there is potential for alternative sources of LNG to meet its requirements for the independent systems in the future but it does not consider that this would materialise in the short or possibly medium term.

8.24. We recognise that the LNG storage costs at Glenmavis make up a large element of SGN's costs to serve the independent systems and given the current consultation on the future regulatory approach to these facilities there is a potential risk that the costs to SGN could vary materially. However, in principle, we consider that a pass through arrangement for these costs would not provide an incentive on SGN to consider and develop alternative sources of LNG for the supply to the independent systems. On this basis we do not support a pass through of this element of their costs.

[30] LNG Storage price control - Initial thoughts, 202/07. www.ofgem.gov.uk

8.25. However we recognise, in setting the gas distribution price control, that we have made an assessment of the potential costs of serving the independent systems. If, through a future decision on the regulatory framework for the LNG storage facilities, we were to require a change that had a material affect on the costs to SGN we would ensure that SGN were not financially affected by such a decision. In this circumstance we would consider whether it would be appropriate to adjust SGN's revenue allowance. Provided SGN had acted appropriately to ensure efficient transportation of gas to the independent systems we would envisage allowances being adjusted to take into account the efficient level of costs.

9. Financial issues

Chapter Summary

This chapter sets out Ofgem's decision on the cost of capital, tax and modelling assumptions for the price control. It also sets out the conclusions of our review of the GDNs' financeability under our proposals.

Cost of Capital

9.1. In order to set the price control allowances for the GDNs, we include an allowed return on the Regulatory Asset Value (RAV). This allowed return is the regulatory cost of capital, and should be at least equal to the licensee's cost of capital - i.e. the level of return required by the financial markets, both debt and equity, in order to provide capital.

9.2. Our initial and updated proposals included a modelling assumption for the weighted average cost of capital (WACC), on a vanilla basis[31], of 4.84 per cent, equivalent to a pre-tax real cost of debt of 3.55 per cent, a post-tax cost of equity of 7 per cent, and gearing of 62.5 per cent. These assumptions were consistent with the approaches used in the previous reviews of transmission (TPCR) and electricity distribution (DPCR4) of taking a medium- to long-term view of appropriate returns. The transmission review, completed last year, concluded that a cost of debt of 3.75 per cent and a cost of equity of 7 per cent were appropriate, and used a gearing assumption of 60 per cent.

9.3. Within updated proposals, we published details of a relative risk analysis that we had performed to compare the operational risks faced by the gas distribution networks with those faced by GB transmission operators. We concluded that gas distribution was at least as risky as transmission.

9.4. In addition, prior to updated proposals, we reviewed a study by Oxera on behalf of the GDNs which identified market evidence that the asset betas of gas distribution companies were higher than transmission companies. Since there are no pure gas distribution or transmission network owners traded within the UK, this study was based on international data.

Respondents' views and the Competition Commission

9.5. One non-GDN response included a report by CEPA, which contends that our relative risk analysis should not impact the cost of capital, since it is primarily concerned with assessing non-systematic risk. In addition, the report argues that

[31] The vanilla WACC represents the allowed cash return on the RAV. It is calculated as a pre-tax cost of debt and a post-tax cost of equity since we have provided a separate specific allowance for tax costs.

Oxera's relative risk analysis is flawed as it is comparing companies regulated by different regulators. Finally the report argues that the market prices for regulated networks demonstrate that the average cost of capital for infrastructure investors is well below Ofgem's assumption.

9.6. The GDNs submitted an updated report from Oxera. This report argued that not only did the risk analysis support a higher cost of equity for the gas distribution networks, but that even if we concluded that there was no risk differential, then the higher gearing levels used in setting the cost of capital for the gas distribution networks necessitated a higher cost of equity, using fundamental corporate finance theory (Modigliani-Miller). In addition, it argued strongly that a cost of debt of no lower than transmission was appropriate.

9.7. The GDNs broadly supported Oxera's conclusions. However, one GDN concluded that the cost of equity should be higher, at 9.69 per cent. This figure was based on a list of risk factors that this GDN believes it faces, and presented as a relative risk analysis in order to derive a differential cost of equity from that used in the transmission price control. However, this analysis included no corresponding list of risk factors that transmission owners might face. Additionally, it relied on an apparently arbitrary selection of probabilities of certain risks transpiring.

9.8. All of the above responses accepted our broad approach of setting the cost of debt and cost of equity separately, and based on wider market conditions. In addition, while there was some comment that the gearing should be no higher than transmission, these responses only argued between 60 per cent and 62.5 per cent.

9.9. The only exception was a non-GDN response that suggested that our allowed return on capital was too high for companies facing such low risks. This respondent referenced its response to initial proposals, which contained an academic article which argues that the current regulatory framework is too generous to companies, while simultaneously providing insufficient regulatory certainty in respect of the return on new investment. Any material change to the well-understood regulatory framework would require lengthy and substantive consultation and analysis, and if applied at short notice would raise great concerns for investors over future regulatory certainty. We do not consider that the latter stages of a review, such as the GDPCR is an appropriate stage to consider such a proposal. Nevertheless, we note that this analysis is consistent with that of CEPA in indicating that the current average cost of capital for infrastructure investors is likely to be below Ofgem's assumption.

9.10. Subsequent to updated proposals, the Competition Commission (CC) published its report on the economic regulation of the London airports companies. In this the CC considered the cost of capital for BAA Ltd. In its assessment of cost of capital, given that BAA had traded equity until relatively recently, the CC focussed on the observed equity beta for BAA, and, using Miller's transformation, concluded that the adjusted equity beta for BAA, with 60 per cent gearing, would be in the range of 0.9 to 1.15. The CC also used a cost of debt of 3.55 per cent, although the primary factors in its conclusions were current market rates, and embedded debt costs for BAA.

Ofgem's decision

Cost of Debt

9.11. Within initial and updated proposals, we concluded that the cost of debt of 3.55 per cent appropriately balanced the spot rates for the cost of debt, the ten year trailing average, and the long-term averages.

9.12. We have continued to monitor the debt markets, which have clearly been more difficult this year. However the real cost of funding has remained below Ofgem's assumption, and the discount to the trailing average has widened since updated proposals. In addition, Ofgem's proposed allowance is still higher than the trailing average, and this gap is likely to grow over the forthcoming period, unless rates rise sharply.

9.13. GDNs have argued that the recent difficulties in the credit markets and the conclusion that gas distribution is at least as risky as transmission both require us to set a cost of debt equal to that for the transmission companies, and to place less weight on the trailing average. GDNs have also argued that the current rates are higher than those at the time of the transmission review, and therefore that it is inappropriate to reduce our assumption for the cost of debt. We do not accept this argument, since, if we were to give weight to the spot rate indicated by this proposal, our cost of debt for both transmission and gas distribution would be well below the proposed levels.

9.14. We recognise that it may be more difficult to raise substantial levels of finance in current markets than has been the case in the period of exceptionally benign market conditions prevailing over recent years. However the risk of such difficulties is recognised in our approach of setting revenue allowances which are consistent with a credit rating which is comfortably within investment grade. We note that where utilities are continuing to raise debt, it is at rates often considerably below our assumption.

9.15. We consider that our proposed allowance properly balances the cost of debt over different periods. We propose to retain our assumption of 3.55 per cent.

Gearing

9.16. The one year control, initial proposals and updated proposals all included a gearing assumption of 62.5 per cent, consistent with the previous price control. We consider this is consistent with a credit rating which is comfortably within investment grade. A small differential to transmission is consistent with the lower financing requirements and therefore lower financial risk, and also is supported by the evidence of actual gearing levels.

9.17. We have decided to keep the gearing level at 62.5 per cent. We consider the impact on the cost of equity below.

Cost of Equity

9.18. We continue to take the view that the allowed return on equity should reflect the balance of all risks that will be faced by companies under the price control proposals, including both systematic and non-systematic risk, to provide appropriate incentives to manage these risks effectively and to invest efficiently in maintaining and developing their networks. We therefore propose to continue our approach of basing the allowed rate of return on equity on the estimated equilibrium level of total market returns, as in TPCR and DPCR4.

9.19. Our review of relative risk indicates that, under these price control conditions, GDNs are overall no less risky, and may be somewhat more risky, than the transmission companies under their current price controls. This supports the view that the allowed rate of return on equity for GDNs should be no lower, and could be somewhat higher, than the 7.0 per cent rate assumed in TPCR. In updated proposals, we indicated we would consider a range of 7.0 per cent to 7.5 per cent for final proposals.

9.20. We accept that, all other things being equal, the use of a higher gearing assumption than was used at TPCR should lead to a commensurately higher expected rate of return on equity, reflecting the greater financial risk borne by shareholders. However, the empirical data relating to UK utilities does not appear to support the view that the relationship between gearing and expected rate of return on equity is a continuous linear function, as theory predicts. We also note that the data set used by Oxera (relating mainly to US businesses) shows similar results to the UK data.

9.21. We acknowledge that there may be other factors affecting the market data which distort the apparent relationship and that it is therefore not safe to assume that the apparent absence of the predicted positive correlation between gearing and equity betas will persist in the longer term. Nevertheless, it does not seem appropriate to disregard the market evidence entirely when setting allowed rates of return for the five years from April 2008.

9.22. Taking these considerations together, and having regard to the additional cost allowances we have decided to make which will, to a degree, reduce the non-systematic risk faced by companies, we consider it is appropriate to base our final proposals on an assumed rate of return on equity of 7.25 per cent (real post-tax).

Conclusion

9.23. Taking the above considerations together, we conclude that an appropriate allowed vanilla return on capital for the gas distribution networks is 4.94 per cent real. Table 9.1 below sets out the underlying assumptions, compared to updated proposals and other recent determinations.

Table 9.1 - WACC for GDPCR with comparators

	GDPCR: Final Proposals	GDPCR: Updated Proposals	TPCR: Final Proposals	CC: BAA (Heathrow)
Cost of debt	3.55%	3.55%	3.75%	3.55%
Cost of equity	7.25%	7%	7%	7.33%
Gearing	62.50%	62.50%	60%	60%
Vanilla WACC	4.94%	4.84%	5.05%	5.06%

9.24. As an overview, we note that this results in a vanilla WACC which is approximately 0.1 per cent lower than TPCR or BAA. With respect to BAA, this is justified by the lower business risk. With respect to TPCR, this is justified by the greater weighting given to the lower costs of debt over the last five years, given the low level of RAV growth over the forthcoming quinquennium. Therefore, we conclude that our decision is consistent with other regulatory determinations as well as the specific evidence provided to this review.

Modelling

9.25. We set out below the background to some of the assumptions used in our financial model.

Tax

9.26. We have calculated the tax allowance for each GDN on a similar basis to the one year control. Allowed capex is split into the capital allowance pools in the proportions forecast by GDNs in their business plans. These proportions have been sense-checked for consistency. We have used a corporation tax rate of 28 per cent and have assumed capital allowances are fully claimed at rates in line with current legislation. We have not reflected the potential changes to capital allowances outlined in this year's budget as the Treasury has not yet confirmed that these changes will take effect.

9.27. While the GDNs may in practice incur some expenditure that is not deductible, such as disallowable entertainment or expensive leased cars, these areas of expenditure are not expected to be material. Conversely, there are some areas of expenditure for which we have made specific provision that may qualify for more than 100 per cent deduction, specifically R&D and environmental remediation. However, it is by no means certain that the GDNs will spend these allowances in such a way as to qualify for the higher rate of relief, and the amounts are not large. On balance, therefore, on the grounds of materiality and simplicity we have made no specific adjustments either for expenditure not qualifying for tax relief, or for expenditure qualifying for more than 100 per cent tax relief. This is consistent with our approach to other price controls.

9.28. We have assumed notional gearing and a real cost of debt in line with our modelling assumption for the cost of capital. Consistent with our approach in DPCR4 and TPCR we intend to make ex post adjustments to reduce the tax allowance if GDNs' actual gearing and actual interest expense both exceed the level assumed in the financial model.

9.29. Our modelling of tax allowances suggests that some GDNs are forecast to make tax losses. We do not propose to give these GDNs 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.

Timing of repex and capex allowances

9.30. The timing of allowances for capex and repex has a material effect on allowed revenue and financial ratios. We have opted to maintain our existing assumptions, as set out below:

- repex - funded 50 per cent in the year incurred and 50 per cent over 45 years; and
- capex, including non-operational capex - funded over 45 years.

We set out the reasons for these decisions in our updated proposals document.

Dividends

9.31. The dividend yield assumed in our model has a small indirect impact on the tax allowance, and affects certain financial ratios. We have assumed that GDNs' dividend yield is 3.5 per cent, which is comparable to the current average for publicly listed UK utilities.

Profiling

9.32. We have not applied any “smoothing” to revenue allowances in our financial model. That is, revenues in a given year are based on our assessment of the relevant costs and a return on investment for that year. We set out the basis for this approach in our initial proposals document. We intend that this is the profile which will be included in the licence.

Assessing financeability

9.33. This section sets out our assessment of the financeability of the GDNs, assuming a notional capital structure, based on the assumptions underlying the cost of capital used for the financial model.

Issues considered

9.34. We have tested our financial model for each of the GDNs against four key ratios: Funds From Operations ("FFO")/Interest, Retained Cash Flow ("RCF")/Debt, Debt/RAV and Post Maintenance Interest Cover Ratio ("PMICR"). The first three of these ratios are consistent with those used in previous price control reviews, as are the target values. We have introduced PMICR as representative of adjusted interest cover ratios, which are used by all the major credit ratings agencies in rating the independent GDNs.

9.35. 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 have met with each of the three ratings agencies to discuss our approach to financeability, which provides us with a useful sense-check on our conclusions. However, we do not seek the rating agencies' approval for our financeability assessment.

9.36. In the fourth consultation document, we noted our reservations about the usefulness of PMICR for testing the financeability of an Ofgem financial model, where it reduces to a function of the cost of capital. We also noted that in the sectors where PMICR was a key metric, most companies had adopted a certain proportion of index-linked debt, which reduced their annual cash interest payments and thus improved this ratio.

9.37. In line with previous price controls, our financial model makes no assumptions about the structure of the debt. However, we have assessed financeability based on whether a GDN funded with nominal debt is likely to be able to achieve financial ratios that are, as a package, consistent with a comfortably investment grade credit rating. Where the PMICR, in particular, is at a level consistent with a weaker investment grade credit rating we give consideration to whether a modest level of index-linked debt would improve the ratio to levels more consistent with a comfortable investment grade rating. In doing so we have regard to the likelihood that the market for index linked debt may not always be available to GDNs.

Outcomes

9.38. The increase in our assumed cost of equity from 7.0 per cent at updated proposals to 7.25 per cent at final proposals has had a positive impact on financial ratios. Additionally, the increase in our capex and repex assumptions relative to the GDNs' view has increased their additional income under the information quality incentive, which improves ratios. Our review of financeability indicates that the package of ratios arising from our notional assumptions for each GDN appears consistent with a comfortable investment grade credit rating.

9.39. As at updated proposals, Scotland performs poorly relative to other GDNs, though we consider that taken in the round, the ratios for this GDN are consistent with comfortably investment grade credit quality. Two further GDNs, Southern and Wales & West, also have relatively weak levels of PMICR.

9.40. The main reason for these relatively weak results, particularly in earlier years of the price control, appears to be the impact of a relatively high level of 'pot 2'[32] expenditure in 2002-07, which is excluded from the RAV until five years after it is incurred. For Scotland, there may also be an impact from the RAV sculpting carried out in order to allow the previous Transco price control to be split between the GDNs in advance of GDN sales. The "sculpting" of the RAV was designed to minimise the variation in charges between the regions. This reduced Scotland's RAV, and hence its future returns.

9.41. When assessing GDNs' financial position, we consider that it is reasonable to adjust for factors within the companies' control, including the impact of their actual performance against incentives. Adjusting for the impact of the pot 2 penalty further improves the financial ratios of all GDNs, reinforcing our conclusion that a financeability adjustment is not required under these proposals.

[32] The allocation of expenditure from 2002-07 into pot 2 is detailed in the one year control final proposals document, ref. 206/06

10. Overall impact of proposals

Chapter Summary

This chapter draws together our analysis set out in earlier chapters in order to outline the overall impact of Ofgem's final proposals.

10.1. Allowed revenue represents the sum of the costs that we consider would be incurred by an efficient GDN in each year of the price control, including a return on capital sufficient to enable it to finance its activities. Within the GDPCR it is calculated as the sum of allowances for the following items:

- operating expenditure, including pensions and our assumed shrinkage allowance;
- the expensed portion of replacement expenditure (50 per cent);
- the return on RAV plus the depreciation. (We assume that companies incur expenditure and receive allowances throughout the year, and therefore calculate this amount indirectly using a 'change in RAV' methodology. This is explained in appendix 14);
- corporation tax on 2008-13 forecast profits, plus an additional allowance for under recovery of tax in 2007-08. (This under recovery arose because in the one year review we used the cost of debt figure from the previous price control. we committed at that time to adjust the tax allowance for the one year control to the level that would be derived using the cost of debt determined in this review);
- the effect of disallowance of a portion of 2002-07 capital expenditure under the rolling incentive. Companies do not receive an allowance on this expenditure for five years;
- any additional income or penalty under the Information Quality Incentive; and
- pension deficit recoveries and under recoveries from the 2002-08 controls.

Overall impact of proposals

10.2. The tables below show the impact of changes to our repex, capex and controllable opex assumptions since updated proposals. They also reflect the impact of changes to the form of the shrinkage incentive and the volumes of shrinkage gas that we forecast GDNs will need to purchase. There are a number of additional factors that affect our best estimate of the amount of revenue that companies will be allowed to recover in each year of the price control, but which are not included within our core allowed revenue figures. These include:

- changes in the assumed cost of purchasing shrinkage gas. Our approach to shrinkage is set out in chapter 7. Our core allowed revenue figures assume that the price of shrinkage gas was the same as the allowance underlying our one year control final proposals. We have updated this assumption to take account of changes to gas prices;
- the impact of the loss of meter work revenue driver. We explain this driver in chapter 6; and

- the effect of the Innovation Funding Incentive. This is considered in chapter 7. We have assumed that companies use the maximum allowance of 0.5 per cent of turnover, of which 80 per cent or 0.4 per cent of turnover is passed through to customers.

10.3. Tables 10.1 and 10.2 set out GDNs' allowed revenue under our base case assumptions, while table 10.3 shows the impact of the additional factors listed above.

Base case

10.4. The overall result of our proposals is an average annual revenue allowance for all GDNs of £2,470 million for the period 2008-09 to 2012-13, representing an average annual increase over this five year period of £47 million or 2.0 per cent[33]. Table 10.1 breaks these figures down by year, while appendix 14 gives more detail on allowed revenues for each GDN.

Table 10.1 - Changes in allowances (average all GDNs, £m, 2005-06 prices)

	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	Average 2008-09 to 2012-13
Allowed revenue	2,327.7	2,409.5	2,462.8	2,463.9	2,496.4	2,519.4	2,470.4
X		-3.5%	-2.2%	0.0%	-1.3%	-0.9%	-2.0%

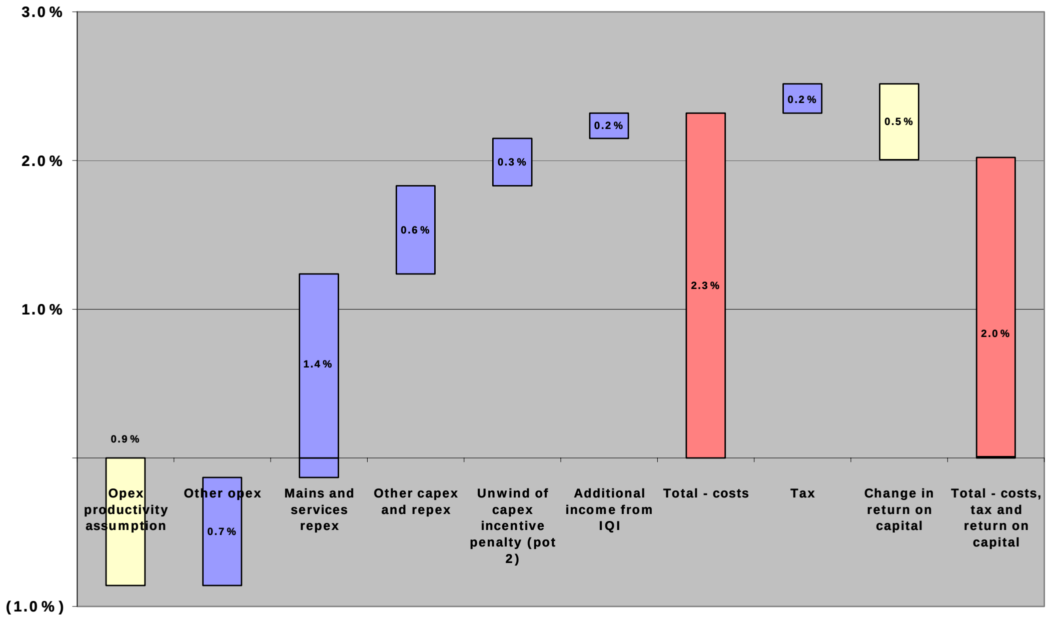
10.5. Since we refer to the price control model as RPI-X incentive regulation, a negative value for X represents an increase in allowances and vice versa.

10.6. The net increase in allowances can be explained by a number of factors. The principal ones are listed below and represented graphically in figure 10.1:

- impact of our opex productivity assumption (-0.9 per cent)[34]
- impact of other changes in opex, principally the impact of real price effects and new cost categories not included in 2007-08 opex allowances (+0.7 per cent)
- increase in impact of mains and services repex (+1.4 per cent)
- increase in other capex and repex (+0.6 per cent)
- impact of 2002-07 'pot 2' expenditure entering the RAV (+0.3 per cent)
- reduction in cost of capital from 2007-08 extension year (-0.5 per cent)

[33] The 2.0 per cent figure represents the average annual increase in allowed revenues (in real terms) over the five years of the price control. This measure is the best way of reflecting the price control settlement, but it is not exactly the same as the impact of our proposals on actual charges levied by GDNs on shippers. Appendix 15 provides more detail on the impact of our proposals on charges.
[34] This figure is based on the difference between actual allowed revenue, including a productivity assumption of 2.5 per cent in each year between 2006-07 and 2012-13, and what allowed revenue would have been had we assumed zero savings.

Figure 10.1- Principal drivers of change in allowances



10.7. Table 10.2 shows the allowances for each GDN.

Table 10.2 - Allowances by GDN (£m, 2005-06 prices)

		Allowed revenue 2007-08	Average annual allowed revenue 2008-13	Average X
NGG	East of England	427.2	430.5	-0.3%
	London	245.1	282.1	-4.9%
	North West	285.5	299.0	-1.6%
	West Midlands	217.8	231.7	-2.1%
NGN	Northern	273.5	290.3	-2.0%
SGN	Scotland	194.3	201.5	-1.2%
	Southern	432.4	468.1	-2.7%
WWU	Wales and West	252.0	267.3	-2.0%
	Total	**2,327.7**	**2,470.4**	**-2.0%**

Impact of additional factors

10.8. Table 10.3 below shows the impact of the additional factors listed above. Columns showing shrinkage, meter work, capacity outputs and IFI adjustments are individual rather than cumulative. The final two columns show the impact of all three adjustments together.

Table 10.3 - Allowances by GDN including additional factors (£m, 2005-06 prices)

		Final proposals - core allowed revenue		Shrinkage price adjusted	Meter work adjusted	IFI adjusted	Final proposals - with all additional adjustments	
		Average annual allowed revenue 2008-13	Average X	Average annual allowed revenue 2008-13	Average annual allowed revenue 2008-13	Average annual allowed revenue 2008-13	Average annual allowed revenue 2008-13	Average X
NGG	East of England	430.5	-0.3%	-5.4	2.4	1.7	429.2	-0.2%
	London	282.1	-4.9%	-3.1	1.3	1.1	281.4	-4.8%
	North West	299.0	-1.6%	-3.9	0.6	1.2	296.9	-1.3%
	West Midlands	231.7	-2.1%	-3.2	2.3	0.9	231.8	-2.1%
NGN	Northern	290.3	-2.0%	-4.1	2.6	1.2	289.9	-2.0%
SGN	Scotland	201.5	-1.2%	-2.2	2.7	0.8	202.8	-1.4%
	Southern	468.1	-2.7%	-5.8	7.5	1.9	471.7	-3.0%
WWU	Wales and West	267.3	-2.0%	-4.1	4.7	1.1	269.0	-2.2%
	Total	**2,470.4**	**-2.0%**	**-31.7**	**24.1**	**9.9**	**2,472.6**	**-2.0%**

Inflation

10.9. The allowed revenue figures in this document are presented in 2005-06 prices, with all changes in allowances shown in real terms. In practice, the impact of inflation means that in each year of the price control, allowed revenues are likely to increase by more than our annual 'X' figure in nominal terms.

10.10. The amount of revenue that GDNs can recover changes each year by inflation (RPI), less Ofgem's permitted change in allowances (X). Table 10.4 shows the impact of inflation on the expected change in allowed revenues between 2007-08 and 2008-09. In subsequent years of the price control, allowed revenue will continue to change by RPI – X each year.

Table 10.4: Estimated impact of inflation on allowed revenue[35]

	Allowed revenue, £m		Change	
	2007-08	2008-09	%	£m
Allowed revenue (2005-06 prices)	**2,327.7**	**2,409.5**	**3.5%**	**81.8**
Plus 2005-06 to 2006-07 inflation (2.6%)	60.0	62.1		
Plus 2006-07 to 2007-08 inflation (3.7%)	88.8	91.9		
Plus 2007-08 to 2008-09 inflation (3.9% forecast)	N/A	100.9		
Allowed revenue (nominal prices)	**2,476.5**	**2,664.3**	**7.6%**	**187.9**
Impact of inflation	148.8	254.9	4.1%	106.1

[35] Inflation on core allowed revenue, the biggest element of our allowances, is based on average RPI between July and December in year t-1, divided by average RPI between July and December in year t-2. Therefore, the estimate for 2008-09 inflation used in this table is a forecast based on data to October 2007, but is likely to be reasonably accurate.

10.11. Appendix 15 gives more detail on the impact of inflation on allowed revenues.

Implications for gas distribution charges

10.12. The price control allowances represent the maximum revenue that the GDNs can collect via gas transportation charges in relation to each year between 2008-09 and 2012-13. In practice, the year-on-year changes in charges are also influenced by other factors, such as the annual correction for under or over recovery of revenues. Appendix 15 sets out the reasons for this difference in more detail and presents an indicative impact on charges.

11. Next steps

Chapter Summary

This chapter briefly discusses the next steps including the cost reporting and licence drafting consultations.

11.1. This document is the final document of seven published during the GDPCR. There are no consultation questions in the document and the GDNs are asked to indicate to Ofgem whether they are minded to accept our final proposals by 7 January 2008. If they decide to accept the proposals, we will undertake a statutory licence consultation early next year leading to the implementation of the price control on 1 April 2008. Further information on this process is detailed below. If any company decides not to accept the proposals, we expect to refer the matter to the Competition Commission.

11.2. In the meantime, if there are any questions on this document or the GDPCR more generally they should be directed to:

Mark Cox
Price Control Policy & Management
Ofgem, 9 Millbank, London, SW1P 3GE
Tel: 020 7901 7458
Email: mark.cox@ofgem.gov.uk

Cost reporting, revenue reporting and the development of the RIGs

11.3. We are working with the GDNs to develop the cost and revenue reporting packs together with the Regulatory Instructions and Guidance (RIGs). We are also amending the RIGs for quality of service to reflect changes to performance standards. We intend to finalise the reporting packs and RIGs by the end of March 2008.

Licence drafting and Statutory Instrument

11.4. In September, we published our initial licence drafting consultation. We have now received responses to this consultation and will be publishing our second licence drafting consultation on 7 December 2007. This work has been informed by a number of working groups with the GDNs. We expect to undertake the statutory consultations on the modifications to the gas transporters' licence in the middle of February.

11.5. In addition, we are currently consulting on changes to the Gas (Standards of Performance) Regulations 2005 to implement revised standards of performance. This is to introduce new or amend existing guaranteed standards and to clarify the mechanism by which customers receive compensation when they are interrupted. In November, we published our second consultation on the Statutory Instrument. The deadline for responses is 19 December 2007. We intend to publish the statutory consultation on the Statutory Instrument in January 2008.

Appendices

Index

Index - Supplementary Appendices

Appendix 1 – 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. The Authority also has other statutory duties in respect of the environment, as set out in various other Acts[36]. References to the Gas Act and the Electricity Act in this appendix are to Part 1 of each of those Acts.[37]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This appendix must be read accordingly[38].

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

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

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[39]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[40]

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:

[36] For example, the Environment Act 1995 and the Countryside and Rights of Way Act 2000
[37] Entitled "Gas Supply" and "Electricity Supply" respectively.
[38] 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.
[39] 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.
[40] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[41] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

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

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

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation42 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.

1.9. The Authority has regard to all of its duties when carrying out its functions.

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

Appendix 2 - Glossary

A

Agency Services Agreement (ASA)

Agreement for the provision of information, data processing, invoicing and supply point administration services in relation to the transmission and distribution of gas in Great Britain.

Area Control Centres (ACC)

The Area Control Centres currently carry out system control activities on behalf of all the GDNs and are located at National Grid Gas' facilities in Hinckley. Activities carried out include monitoring system pressures, flows and alarm management at LTS (Local Transmission System) sites and other key sites on the distribution networks.

B

Business Plan Questionnaire (BPQ)

Expenditure information requested by Ofgem from the GDNs to inform decisions about setting the price control.

C

Capacity (Gas)

The amount of natural gas that can be produced, transported, stored, distributed or utilized in a given period of time under design conditions.

Composite Scale Variable (CSV)

A method of combining a number of different cost drivers into a single driver for regression analysis using fixed pre-determined weights

D

Direct activities (operating expenditure)

Direct activities are the core activities carried out by GDNs e.g. repair and maintenance of pipe-lines, provision of emergency service response to reported gas leaks, etc.

Distribution Network Operator (DNO)

DNOs are holders of electricity distribution licences. Licences are granted for specified geographical areas. Currently in Great Britain there are seven companies who own the fourteen licensed distribution areas.

Distribution Price Control Review 4 (DPCR4)

The price control review for the electricity distribution network operators which covers the five years from 1 April 2005 to 31 March 2010.

F

Flat capacity

Flat capacity gives the holder the right to offtake a volume of gas during the day at a constant hourly rate

Flexibility (flex) capacity

Flex capacity gives the holder the right to offtake a volume of gas according to a profile that varies over the day.

G

Gas Distribution Network (GDN)

GDNs transport gas from the NTS to final consumers and to connected system exit points. There are currently eight GDNs in Great Britain which comprise twelve LDZs.

Gas Distribution Price Control Review (GDPCR)

The review of the price control applying to gas distribution networks. The review will extend the existing price control for the year 2007-8 and reset the control for the period commencing 1 April 2008.

Gas Transporter (GT)

The holder of a Gas Transporter's licence in accordance with the provisions the Gas Act 1986.

Gas Transportation Management System (GTMS)

GTMS is the interface between the GDN outstations and the control centre.

Gemini system

The Gemini information system replaced the AT Link (energy balancing) information system and the RGTA (entry capacity trading) information system.

Guaranteed Standards of Performance (GSOP)

Guaranteed standards of performance set service levels that must be met in each individual case. If a gas transporter fails to provide the level of service required, it must make a payment to the consumer affected, subject to certain exemptions.

H

Health and Safety Executive (HSE)

The Health and Safety Commission is responsible for health and safety regulation in Great Britain. The Health and Safety Executive and local government are the enforcing authorities who work in support of the Commission.

I

Independent Distribution Network (IDN)

The four of its eight GDNs that NGG sold to three new owners on 1 June 2005. These include Northern, Scotland, Southern and Wales & West.

Independent Gas Transporter (IGT)

IGTs are GT licence holders that own and operate small local gas networks and levy distribution charges on shippers.

Indirect activities (operating expenditure)

Indirect activities are activities that are not part of the core services of a GDN but which are undertaken to support those activities e.g. human resources.

L

Local Distribution Zones (LDZs)

LDZs are low pressure pipe-line systems which deliver gas to final users and Independent Gas Transporters. There are twelve LDZs which take gas from the high pressure transmission system for onward distribution at lower pressures.

Local Transmission System (LTS)

The pipe-line system operating at >7barg that transports gas from NTS offtakes to distribution systems. Some large users may take their gas direct from the LTS.

N

National Grid Gas (NGG)

The GT licence holder for the North West, West Midlands, East England and London GDNs. NGG also hold the GT licence for the gas national transmission system (NTS). Prior to 10 October 2005, NGG was known as Transco.

National Transmission System (NTS)

National Grid's high pressure gas transmission system. It consists of more than 6,400 km of pipe carrying gas at pressures of up to 85 bar (85 times normal atmospheric pressure).

NTS offtake capacity

Built to ensure sufficient pipe-line capacity is available to convey gas from the NTS to the GDNs and NTS direct connects at the required rate and quantities.

Northern Gas Networks (NGN)

The GT licence holder for Northern GDN.

O

One in twenty planning standard (1 in 20)

A licence obligation imposed on GDNs under Standard Special Condition A9 (Pipe-Line System Security Standards). A GDN is required to plan and develop its pipe-line systems so as to enable it to meet peak aggregate daily demand for gas which is likely to exceeded (whether on one or more days) only in one year out of twenty years.

Overall Standard of Performance (OSOP)

Overall standards of performance set minimum average levels of performance in areas where it is not necessarily appropriate to put in place guarantees for individual consumers. These are determined separately for each gas transporter by the Authority.

P

Priority Services Register (PSR)

PSR includes domestic consumers who are of pensionable age, have a disability, have long term ill health, and/ or are blind or visually impaired. Individuals on this register qualify for a selection of free services by gas and electricity suppliers.

R

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee’s regulated distribution 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 allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

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

Scotia Gas Networks (SGN)

The GT licence holder for Southern GDN and Scotland GDN.

Shrinkage

Shrinkage gas is gas lost from the network through leakage, theft or own use gas.

System Operation Managed Service Agreements (SOMSAs)

SOMSAs are contracts between NGG and each GDN purchaser under which NGG carries out system operation on behalf of the new GDNs. They provide for the scheduling, monitoring and control (under the direction of the independent distribution network, i.e. IDN) of flows of has in the parts of the GDN system operable remotely from the control centre using the control system, in order to achieve a physical balance. Other services provided under the SOMSAs include:

- services for the notification of call-outs, alarms and faults;
- coordination services in the event of contingencies and emergencies;
- services to support the preparation of a plan covering scheduling of engineering; works and maintenance affecting the remotely operable parts of the GDN system; and,
- recording details of engineering works and maintenance carried out.

T

Therm

A unit of heating value equivalent to 100,000 British thermal units (Btu) (0.1 MMBtu).

Third party damage or water ingress (TPWI)

Third party damage occurs when a gas supply interruption is caused by a third party. Water ingress is an incident whereby water has escaped from pipes vested in water companies and entered pipes operated by public gas transporters. From there, water has then sometimes penetrated into domestic premises, causing damage to the customers' gas appliances[43].

Traffic Management Act (TMA)

The Traffic Management Act is intended to provide better conditions for all road users through proactive management of the national and local road network[44].

Transco plc (see National Grid Gas)

Transco plc changes its name to National Grid Gas on 10 October 2005.

Total factor productivity (TFP)

TFP is a measure of the level of outputs produced from a given quantity of input factors. Changes in TFP reflect changes in the efficiency with which those factors are used.

Transmission Price Control Review (TPCR)

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

U

UK-Link

UK-Link is the central information system that shippers and suppliers use to interface with the GTs and each other.

Uniform Network Code (UNC)

As of 1 May 2005, the UNC replaced National Grid Gas' Network Code as the contractual framework for the NTS, GDNs and system users.

W

Wales & West Utilities (WWU)

The GT licence holder for Wales & West GDN.

Water ingress

An incident where water enters gas pipes resulting in a loss of gas supply.

---

[43] http://www.ofwat.gov.uk/aptrix/ofwat/publish.nsf/Content/rd032001
[44] Department for Transport:
http://www.dft.gov.uk/stellent/groups/dft_roads/documents/divisionhomepage/032064.hcsp

Water Services Regulation Authority (Ofwat)

Ofwat is the economic regulator of the water and sewerage industry in England and Wales.

X

xoserve

A transporter agency which provides a single, uniform interface between the IT systems of relevant GTs and shippers.

Appendix 3 - 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:

- Does the report adequately reflect your views? If not, why not?
- Does the report offer a clear explanation as to why not all the views offered had been taken forward?
- Did the report offer a clear explanation and justification for the decision? If not, how could this information have been better presented?
- Do you have any comments about the overall tone and content of the report?
- Was the report easy to read and understand, could it have been better written?
- Please add any further comments?

1.2. Please send your comments to:

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