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# Gas Distribution Price Control Review Updated Proposals Document

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

**Overview:**

This document sets out our updated 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 updated proposals build on our initial proposals, published in May, and have been informed by actual 2006-07 cost data, revised GDN forecast cost assessments and analysis that has been carried out since initial proposals.

We are proposing an on going efficiency improvement of 2.5 per cent per annum in the GDNs' operating expenditure. We recognise that fulfilling the Health and Safety Executive's requirements on mains replacement will result in higher replacement expenditure than in the previous price control period (2002-2007). Nonetheless, our proposals are lower than companies' forecasts because we consider this investment can be delivered more efficiently. The net effect of Ofgem's updated proposals is a small increase in the revenue which GDNs can recover from their customers of an average of 1.3 per cent a year in real terms.

We have updated some of our policy proposals in light of responses and are proposing a number of further incentives on the companies. We are also consulting on our cost of capital relative risk analysis.

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## Context

In May 2007 we set out 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.

This document updates these proposals. In particular, initial proposals have been updated for 2006-07 actual GDN cost data, a number of changes have been made to our analysis to address detailed concerns raised in responses to initial proposals, and the analysis has been updated for areas that were not complete at the time of initial proposals. The document also sets out our further thinking on a number of incentives and consults on the comparative risk analysis we have carried out and the potential impact this will have on cost of capital.

Our next document on the GDPCR will be our final proposals in early December 2007. The main decision for final proposals will be the cost of capital which the Authority will consider in the context of the overall package of proposals. There may be some smaller or company specific points that will also be addressed at this time and any changes as a result of responses to updated proposals.

## Associated Documents

- 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).

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# Summary

Our principal objective is to protect the interests of gas and electricity consumers. In the context of gas distribution networks (GDNs) one way we do this is 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, to deliver an agreed quality of service and contribution to sustainability and to meet their statutory obligations and licence conditions.

In May we published our initial proposals for the review which will apply for the period from 1 April 2008 to 31 March 2013. Since then we have carried out further analysis, new information has become available and we have had the opportunity to consider detailed feedback both in the form of written responses to initial proposals and at meetings with the price control team and a committee of the Authority.

Our updated proposals take account of all this additional analysis and information. Some important decisions will only be taken as part of our final proposals in December, in particular on the appropriate cost of capital for these businesses in the specific context of the overall settlement. Nonetheless we consider that these updated proposals form a robust basis on which to set allowances for the next five year period and provide a clear indication to customers and GDNs of our view on the appropriate level of revenue and associated outputs and incentives that should apply.

In assessing operating expenditure (opex), we have repeated the analysis we carried out for initial proposals using actual data for 2006-07 rather than the companies' forecasts. Actual opex is lower than forecast and on its own this would have had the effect of reducing our forecast opex at initial proposals by 4.8 per cent. We have continued to use the overall method adopted in producing our initial proposals. In particular we have made use of benchmarking at an activity level as well as the more traditional approach of benchmarking at a total operating cost level. We are now setting revenue allowances based on the performance at the upper quartile level, i.e. between second and third best GDN. We have also made changes to the way the detailed benchmarking is carried out and are taking account of the costs of environmental remediation, waste management, training and apprentices and additional costs from operating in densely or sparsely populated areas. We have not changed our assumptions on real input price growth or future improvements in productivity which we have continued to estimate at 2.5 per cent per annum.

The net effect of all these changes has been to increase our forecast opex from initial proposals by £30 million per annum or 5 per cent. We have also proposed a revenue driver to take account of the loss in revenue which the GDNs expect to incur as contracts for meter work (which GDNs have historically used to increase the productive time of their emergency workforce) come up for renewal.

In assessing capital (capex) and replacement expenditure (repex), we have adopted a broadly similar approach in preparing updated proposals – updating for 2006-07 actuals, modifying the detailed method to take account of responses and carrying out a detailed review of capex on the Local Transmission System (LTS). The timing of LTS capex is in some cases very sensitive to forecasts of demand. New information on demand forecasts will become available in October. This may make it appropriate to revise our assessment of the timing of some of this capex in final proposals.

In addition GDNs were asked to resubmit their capex and repex forecasts in response to the information quality incentive (IQI). The effect of the IQI is to increase capex and repex allowances by 3 per cent. GDNs who overspend our assessment of capex and repex will bear between 30 and 35 per cent of the additional cost. Conversely where they underspend they will be allowed to retain the same percentage. The table below summarises our assessment of opex, capex and repex (before the IQI and the meter work revenue driver).

| | | | Average annual amounts 2008 -13 | | | |
|---|---|---|---|---|---|---|
| (in 2005-06 prices) | Average annual actual 2002-07 | 2007-08 Allowances | Initial proposals | GDN forecast | Updated proposals | Difference forecast to updated |
| | £m pa | £m pa | £m pa | £m pa | £m pa | % |
| Opex | 660.1 | 652.5 | 598.0 | 722.1 | 628.0 | -13% |
| Capex | 260.7 | 358.4 | 328.2 | 396.8 | 319.2 | -20% |
| Repex | 491.9 | 588.0 | 654.0 | 784.5 | 678.6 | -13% |

In order to inform our decision the appropriate cost of capital for GDNs in the context of this price control, we said we would consider the comparative risk of gas distribution with transmission. We have now completed a bottom-up review of the operational risks and have also reviewed a paper prepared for the GDNs using market data. Our initial view is that the risks faced by the GDNs under the price control proposed are at least as great as those faced by the transmission owners (whose price controls set last year incorporated a real cost of equity of 7 per cent). It may therefore be appropriate when we determine the cost of capital as part of our final proposals to set the cost of equity above the mid-point of our previously stated range of 6.5 to 7.5 per cent. For the purposes of the initial proposals we calculated the GDNs allowed revenue using a vanilla cost of capital of 4.84 percent (equivalent to a post tax cost of capital of 4.2 per cent). We have used the same number in updated proposals. Taken together our updated proposals allow GDNs to recover £2.420 billion (in 2005-06 prices) per annum. This is an additional £51 million when compared to initial proposals and represents a real increase of 1.3 percent per annum over our current revenue allowances. Our estimate is that having taken account of the impact of incentive schemes and changes in the price of gas, the effect on the average domestic consumer will be a real increase of approximately £1 per annum.

In addition to the initiatives set out in initial proposals targeted at sustainability, quality of supply and the environment, we are now proposing to include an innovation funding incentive which will allow GDNs to pass through research, development and demonstration costs up to 0.5 per cent of allowed revenue annually for projects targeted at delivering environmental and sustainability benefits. We have carried out further work on the environmental implications of gas lost through leakage from the distribution network and are proposing an additional emissions incentive based on the shadow cost of carbon.

We expect to publish our final proposals in December, having considered carefully any feedback received in response to these updated proposals.

# 1. Introduction

**Chapter Summary**

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

**Question box**

There are no specific questions in this chapter.

## 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. In May we published our initial proposals for these revenue allowances. This document updates our initial view on these allowances, taking 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 have made in light of responses to our May consultation. We are seeking wider views on these findings ahead of our final proposals which we expect to publish in December.

1.3. In our initial proposals we set out a range of further incentives that together with the proposed allowances we consider will best protect consumers' interests. This document sets out where these incentives have been updated following responses to initial proposals and our updated thinking along with further proposed incentives.

1.4. This document is not intended as a comprehensive update of all elements of our initial proposals but rather an update where we have new proposals or wish to modify our approach in advance of final proposals.

## Structure of this document

1.5. This consultation document is organised as follows:

- Chapter 2 details our updated view on the form, structure and scope of the price control.
- Chapters 3 and 4 set out our updated 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 latest thinking on quality of service.

- Chapter 6 discusses and sets out our proposals for rolling incentives, a capacity outputs incentive and a loss of meter work revenue driver.

- Chapter 7 details our thinking in the area of sustainable development. In particular it provides an update to the proposed shrinkage incentive, proposes a new leakage incentive which focuses on the environmental impact from gas leakage, sets out our proposal for an innovation funding incentive for sustainable development and provides an update on our network extensions proposals.

- Chapter 8 provides an update on the funding of xoserve and the arrangements for independent systems.

- Chapter 9 provides Ofgem's analysis and thinking on the cost of capital and tax, and provides a view on the financeability of the GDNs under the updated proposals.

- Chapter 10 draws together our analysis set out in earlier chapters in order to outline the overall impact of Ofgem's proposals.

- Chapter 11 details the next steps for the project before final proposals are published in December.

1.6. There are a number of supplementary appendices which provide more detail on our updated proposals. In addition, Appendix 5 sets out how we have responded to the individual points made by respondents to our initial proposals. Appendix 3 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 updated thinking on three of the areas detailed in our initial proposals on the form, structure and scope of the price control.

**Question box**

There are no specific questions in this chapter.

## Scope of the price control

2.1. Initial proposals set out some changes to the scope of the price control and the treatment of a number of excluded services and pass through items. In addition, consideration was 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. Initial proposals noted that a decision on the approach to each service would be taken as and when the consent expires.

2.2. We have considered this matter further, particularly as a large number of these consents will expire by 1 April 2008. We note that 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.

2.3. 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 including the need for a single public telephone number it appears more practical to maintain the current arrangements. It is proposed that the emergency call handling arrangements are included with 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.

2.4. There are other services smaller in scale that are not described above which we propose to treat on a case by case basis.

2.5. In responses GDNs have also raised Post Emergency Metering Services (PEMS) as a potential excluded service. Independently of GDPCR, we have been considering the arrangements around PEMS. We will shortly be issuing an open letter setting out our proposed approach for consideration. Subject to the conclusion of this exercise any changes to the licence will be addressed through the GDPCR licence drafting consultations.

## Dealing with uncertainty, new obligations and costs

2.6. Initial proposals set out that we would include 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. We 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. It is proposed to follow the approach and parameters utilised in DPCR4 to manage the uncertainty associated with TMA.

2.7. 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 is set out in our licence drafting consultation, reference number 221/07. We propose to use a materiality threshold of 1 per cent of revenue in both cases before a reopener is triggered.

## Correction mechanism

2.8. Initial proposals set out our intention to implement a two tier recovery mechanism similar to that introduced for DPCR4. There was general support for this approach but responses to initial proposals made the point 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.

2.9. 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 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 to address the volatility concern.

2.10. 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 more accurately recover their allowed revenue is greatly improved we will seek to adjust the correction mechanism to reduce the deadband materially.

[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 updated views on a range of policy issues associated with our analysis of the GDNs' forecast operating expenditure along with our updated proposals for operating expenditure allowances.

**Question box**

**Question 1:** Do you agree with our revised approach to setting opex allowances and the proposed allowances we have derived using that approach?
**Question 2:** Do you agree with our approach to the additional operating cost items included in these proposals covering the areas where our work was incomplete at initial proposals?

## Introduction

3.1. In initial proposals we determined opex allowances for each GDN based on PB Power and LECG's work, together with our own assumptions for regional factors, real input price growth and productivity and certain other specific adjustments.

3.2. These updated proposals have taken the analysis from initial proposals as our starting point. We have then updated the analysis for 2006-07 actual costs, made a number of changes to take account of responses to initial proposals, and more detailed analysis that we have undertaken and carried out further work on areas that were not complete at the time of initial proposals. As before we have used benchmarking extensively in assessing operating costs.

## Total operating costs

3.3. Table 3.1 below sets out a high level summary by GDN of our revised assessment of efficient costs which is discussed further below.

**Table 3.1 - Summary of operating expenditure assessment including upper-quartile uplift (excluding shrinkage) (£'m in 2005-06 prices)**

| Ofgem Updated Proposals | | 2007-08 Allowance | Average annual GDN forecast 2008-09 to 2012-13 | Average annual allowance over 2008-09 to 2012-13 | | Difference to Initial proposals | % |
|---|---|---|---|---|---|---|---|
| | | | | Initial Proposals | Updated Proposals | | |
| NGG | East of England | 109.8 | 123.0 | 95.7 | 93.9 | -1.8 | -2% |
| | London | 71.7 | 86.4 | 67.0 | 71.2 | 4.2 | 6% |
| | North West | 80.4 | 93.8 | 74.0 | 76.7 | 2.7 | 4% |
| | West Midlands | 59.9 | 67.3 | 54.0 | 58.1 | 4.1 | 8% |
| NGN | Northern | 77.3 | 81.8 | 73.0 | 75.1 | 2.1 | 3% |
| SGN | Scotland | 65.2 | 68.1 | 57.0 | 63.6 | 6.6 | 12% |
| | Southern | 105.5 | 117.7 | 105.4 | 113.6 | 8.2 | 8% |
| WWU | Wales & West | 82.7 | 84.0 | 71.9 | 75.9 | 4.0 | 6% |
| | **Total All GDNs** | **652.5** | **722.1** | **598.0** | **628.0** | **30.0** | **5%** |

3.4. The remainder of this chapter considers the updated opex analysis in detail, focussing first on the update of the bottom-up analysis (excluding the uplift) and then considering the comparisons with the top-down work and the overall opex allowances including the uplift.

3.5. Although our analysis is largely based on the disaggregated activities, the costs derived from that analysis should not be regarded as an allowance or separate target for individual activities, they are only components in our determination of an overall revenue allowance.

## Updated bottom-up analysis (excluding uplift)

3.6. The following table summarises the impact of our updated bottom-up analysis on the GDNs' opex allowances. It shows the changes between our initial proposals and updated proposals excluding uplifts which are discussed later in this chapter. The revised bottom-up analysis is presented in three stages:

- updating the initial proposals analysis to reflect the 2006-07 actuals;
- our changes to the methodology to take into account responses to initial proposals and further detailed analysis we have undertaken; and
- building in additional allowances in those areas where our analysis was not complete for initial proposals.

## Table 3.2 Opex excluding uplift (£'m 2005-06 prices)

| | Ofgem initial proposals opex - annual average allowances | East of England | London | North West | West Midlands | Northern | Scotland | Southern | Wales & West | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| IP | Direct Opex | 64.5 | 45.4 | 50.2 | 36.0 | 52.8 | 40.8 | 79.9 | 51.6 | 421.1 |
| | Indirect opex | 25.8 | 17.6 | 19.6 | 15.1 | 16.1 | 13.1 | 19.6 | 16.4 | 143.3 |
| | Other | 0.3 | 0.5 | 0.2 | 0.1 | 0.2 | 0.1 | 0.3 | 0.1 | 1.8 |
| | Total | 90.6 | 63.5 | 70.1 | 51.1 | 69.1 | 54.0 | 99.9 | 68.1 | 566.3 |

| | Update for 2006-07 actuals | East of England | London | North West | West Midlands | Northern | Scotland | Southern | Wales & West | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Update for actuals | Direct Opex | 61.9 | 45.2 | 49.4 | 38.1 | 52.1 | 41.3 | 74.4 | 50.7 | 413.0 |
| | Indirect opex | 20.9 | 11.6 | 16.2 | 12.3 | 15.2 | 12.9 | 19.4 | 15.5 | 124.0 |
| | Other | 0.3 | 0.5 | 0.2 | 0.1 | 0.2 | 0.1 | 0.3 | 0.1 | 1.8 |
| | Total | 83.1 | 57.3 | 65.8 | 50.5 | 67.5 | 54.4 | 94.0 | 66.3 | 538.9 |
| Change from IP | | -8.3% | -9.7% | -6.1% | -1.3% | -2.3% | 0.7% | -5.8% | -2.6% | -4.8% |

| | Update based on methodology changes/corrections | East of England | London | North West | West Midlands | Northern | Scotland | Southern | Wales & West | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Methodology changes | Direct Opex | 61.0 | 48.9 | 50.6 | 38.2 | 50.9 | 42.0 | 81.5 | 48.2 | 421.4 |
| | Indirect opex | 23.7 | 13.4 | 18.6 | 14.2 | 16.8 | 13.7 | 20.6 | 17.2 | 138.3 |
| | Other | 0.4 | 0.6 | 0.2 | 0.2 | 0.3 | 0.9 | 0.5 | 0.2 | 3.3 |
| | Total | 85.2 | 62.9 | 69.5 | 52.6 | 68.1 | 56.6 | 102.6 | 65.5 | 563.0 |
| Change from IP | | -6.0% | -0.9% | -0.8% | 2.8% | -1.4% | 4.9% | 2.7% | -3.7% | -0.6% |

| | Update including additions | East of England | London | North West | West Midlands | Northern | Scotland | Southern | Wales & West | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Additions | Direct Opex | 61.0 | 48.9 | 50.6 | 38.2 | 50.9 | 42.0 | 81.5 | 48.2 | 421.4 |
| | Indirect opex | 23.7 | 13.4 | 18.6 | 14.2 | 16.8 | 13.7 | 20.6 | 17.2 | 138.3 |
| | Other | 0.4 | 0.6 | 0.2 | 0.2 | 0.3 | 0.9 | 0.5 | 0.2 | 3.3 |
| | - Aprentice and training costs | 2.1 | 1.2 | 1.6 | 1.1 | 1.6 | 1.7 | 2.5 | 1.7 | 13.6 |
| | - Waste management | 0.4 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 | 0.5 | 0.2 | 2.4 |
| | - Environmental remediation | 0.9 | 0.9 | 0.9 | 0.9 | 1.0 | 0.5 | 0.5 | 2.3 | 8.1 |
| | - Other regional costs | 0.0 | 1.9 | 0.0 | 0.0 | 0.0 | 1.0 | 1.2 | 2.0 | 6.1 |
| | Total opex including additions | 88.6 | 67.3 | 72.4 | 54.8 | 70.9 | 60.1 | 107.3 | 71.8 | 593.2 |
| Change from IP | | -2.2% | 6.0% | 3.3% | 7.1% | 2.7% | 11.3% | 7.5% | 5.5% | 4.7% |

## Updating for 2006-07 actual costs

3.7. The first stage in updating our analysis for 2006-07 was to ensure that the costs data was submitted on a consistent ongoing cash cost basis with any disallowable costs removed. We have focussed on a number of key areas including:

- non-cash costs such as provisions and accruals;
- non-recurring or atypical costs such as restructuring costs or one-off items;
- costs that should be disallowed for regulatory purposes such as related party margins; and
- accounting policies of the various GDNs such as their capitalisation policies.

3.8. A summary of our proposed adjustments is set out in table 3.3 below.

**Table 3.3 - Accounting adjustments to 2006-07 cost data**

| £'m 2005-06 prices | NGGD | | | | NGN | SGN | | WWU |
|---|---|---|---|---|---|---|---|---|
| | East of England | London | North West | West Midlands | Northern | Scotland | Southern | Wales & West |
| **Controllable operating costs** | **119.9** | **83.3** | **98.1** | **66.9** | **79.3** | **69.4** | **127.6** | **86.7** |
| Reconciliation to regulatory accounts | 0.0 | 0.0 | 0.0 | 0.0 | 1.4 | 0.4 | 0.8 | 0.5 |
| Non-cash costs - provisions | -1.3 | -0.8 | -1.0 | -0.7 | -0.1 | 0.0 | 0.0 | -1.5 |
| Atypical costs | -0.5 | 0.0 | -0.2 | -0.1 | -0.3 | -0.5 | -0.9 | -1.5 |
| Disallowed costs - related party margins | -0.1 | -1.2 | 0.0 | 0.0 | 0.0 | -1.2 | -2.6 | 0.0 |
| Accounting policies - capitalisation | 0.0 | 0.0 | 0.0 | 0.0 | 0.5 | 0.2 | 0.3 | 0.1 |
| Total adjustments | -1.8 | -2.1 | -1.3 | -0.9 | 1.5 | -1.1 | -2.4 | -2.3 |
| **Adjusted controllable operating costs** | **118.1** | **81.2** | **96.8** | **66.0** | **80.8** | **68.3** | **125.2** | **84.4** |

3.9. In practice, as all GDNs are using 2004-05 accounting policies and issues on the application of these policies were identified and corrected through the accounting work on the 2005-06 data, the differences are small and we have only made relatively small adjustments.

3.10. 2006-07 actual costs were lower than had been forecast by the GDNs, resulting in opex falling by 4.8 per cent overall. The impact for each GDN is shown in table 3.2 above.

## Responses to initial proposals

3.11. The GDNs have raised a range of issues with our detailed activity-based benchmarking. They are concerned about both the overall level of allowances and relative assessment of individual GDNs. For instance, the IDNs highlight that NGG received 55 per cent of the initial proposals indirect opex allowances even though it should be achieving economies of scale for such activities as a result of owning four GDNs.

### Direct cost benchmarking

3.12. The GDNs have a range of concerns with the direct cost benchmarking. They have suggested that some of the cost drivers which PB Power has used are inappropriate. For example, one GDN has suggested that greater emphasis should be placed on customer numbers in benchmarking work management.

3.13. The GDNs consider that our assumption of declining volumes of external publicly reported gas escapes (PREs) and condition-based repairs is significantly overstating the impact of mains replacement. One of the GDNs has highlighted that the volumes of external gas escapes and repairs have been rising in their area.

3.14. The GDNs are concerned with the robustness of the maintenance analysis. They have highlighted issues with the allocation of overall maintenance costs across the various maintenance activities and consider that PB Power's bottom-up analysis makes a range of assumptions on maintenance costs that are not substantiated.

**Indirect cost benchmarking**

3.15. The GDNs argue that there are a number of weaknesses with the benchmarks that we used in initial proposals for indirect opex. They consider that the external benchmarks for HR, audit, finance and regulation are inappropriate and lead to unachievable levels of efficiency savings. They highlight that some of the IDNs have started these functions from scratch and that it is unlikely for them to already be experiencing significant inefficiencies. They note that there are differences in scope for some of these functions with the external comparator companies which require further normalisation.

3.16. Several of the GDNs have suggested that the use of revenue as a scale variable in the indirect opex analysis is inappropriate. They have suggested that compared to external companies revenue figures are artificially depressed as they take into account the RAV which includes a privatisation discount. They consider that total spend would be a better scale variable for indirect opex. One of the GDNs has commissioned work by consultants putting forward alternative benchmarks.

3.17. The GDNs suggest that we need to make further adjustments for differences in business structure before carrying out the comparative analysis. For example, they note Scotia has a more decentralised business structure than NGG. They believe that this may lead to more indirect activities being carried out in the field rather than centrally and may cause SGN's indirect opex to appear artificially efficient.

3.18. One of the GDNs has noted the business model adopted by NGN in outsourcing management and operation of its distribution network to United Utilities Operations Limited (UUOL) may lead to greater capitalisation of indirect costs. This may make NGN appear more efficient on opex. A number of the GDNs are concerned with the provision of some support services by SSE to SGN at marginal cost. They consider that this may lead to an unsustainably low level of benchmarks.

**Regional labour costs**

3.19. Some GDNs put forward additional evidence to support higher regional adjustments for labour costs associated with working in London. One GDN has suggested that the existing adjustments are overstated.

## Changes to the bottom-up analysis

3.20. We have made a number of changes to our bottom-up analysis to take into account responses to initial proposals, further detailed analysis we have undertaken and to correct an error in PB Power's pension normalisation which was included in our initial proposals for direct opex and affected all GDNs. Further detail of our updated direct and indirect opex analysis is set out in Appendix 7.

**Direct opex**

*Revised workload assumptions for direct opex*

3.21. Our analysis for initial proposals assumed that external PREs would reduce by 1.8 per cent per annum and internal PREs would remain flat. We assumed that condition based repairs to mains and services would reduce by 3 per cent per annum due to the mains replacement programme. The historical data from the GDNs does not support such levels of reductions in workload and all GDNs argued that these reductions would not be seen in the next price control period. We have changed the assumptions to a 0.8 per cent per annum reduction in external PREs, a 0.5 per cent per annum increase in internal PREs due to growing awareness of the safety issues relating to carbon monoxide and a 1.5 per cent per annum reduction in condition based repairs. This increases our forecast emergency, repair and work management workloads and the associated allowances for each GDN.

*Maintenance opex*

3.22. As part of the update work PB Power focused on how the maintenance analysis could be improved. They have now adopted an approach that looks at overall maintenance costs rather than looking separately at LTS, storage and other maintenance costs. They first identified routine maintenance costs that occur on an annual basis and carried out a regression of these costs on a composite scale variable to determine the efficient level of expenditure. They then added in additional non-routine costs based on a bottom-up assessment. These non-routine maintenance costs include activities such as LTS on-line inspections, holder painting and governor overhauls.

3.23. We have made a number of further adjustments to PB Power's maintenance regression analysis to simplify the scale variable. This is now based on the numbers of pressure reduction stations, NTS offtakes, governors and holders which we consider to be the main drivers of maintenance costs. We consider that this revised approach to maintenance is more robust and gives results that are reasonable in the context of historical expenditure for each GDN.

3.24. The revised maintenance analysis gives higher allowances in aggregate across the GDNs but there are some significant variations between companies. Southern receives the largest increases in maintenance costs and Northern and WWU experience the largest reductions. Our forecast maintenance opex for Southern has increased as it performs well in the overall maintenance regression. Northern and WWU's maintenance allowances have reduced as they had a high level of other maintenance costs which were not benchmarked in the initial proposals analysis. These costs have now been benchmarked and as a result some of these additional other maintenance activity costs have been disallowed.

*Other direct opex*

3.25. We consider that the regression analysis for other direct opex based on 2006-07 data is not sufficiently robust to be used to determine our expenditure forecasts for each GDN. Our forecasts for other direct activities have therefore been based on GDN projections of their own expenditure for 2008-09 to 2012-13 but adjusted for our own view of real price effects and ongoing efficiencies.

*Regional labour factors*

3.26. We have considered the additional evidence presented on labour costs and consider it appropriate to revise the regional factors for direct labour costs for Southern from 1.07 to 1.08 and London from 1.16 to 1.18. This leads to a very small reduction in the regional factors for the other GDNs. This takes into account better information on the proportion of direct opex activities that need to be located locally within the M25 as opposed to the GDNs having the flexibility to locate them in the lowest cost areas.

3.27. SGN has suggested that Southern’s direct labour regional factor needs to be increased to reflect higher labour costs in the South-East relative to the rest of the country. It notes that the labour market in that area is closely tied to the London market . We have made no further adjustment for this as this impact is not adequately quantified, being based on largely theoretical arguments and in any event labour costs in some other areas of the country will also be linked to London.

3.28. We do not consider any further adjustments to the London or Southern contract labour regional factors are required. These regional factors already adequately reflect the proportion of work carried out in London.

3.29. We do not consider that a regional adjustment is appropriate for East of England GDN even though a small proportion of its work is carried out within the M25. A number of other GDNs have a proportion of their area within major metropolitan centres.

*xoserve*

3.30. xoserve actual 2006-07 costs were also submitted and reviewed as part of this update work. LECG have carried out their analysis on the same basis as for initial proposals, taking into account comments received on initial proposals. The result of this update work is a slight reduction in the efficiency savings proposed for xoserve.

3.31. Certain xoserve services will be moving to a user pays basis, we have therefore removed the costs associated with these services (£2.83m per annum) from xoserve's opex and apportioned this figure across the gas transporters in the same ratio as their share of xoserve's opex.

## Indirect opex

3.32. We have made a number of changes to the approach to indirect opex to reflect concerns raised in response to initial proposals. Further details of our updated analysis are set out in appendix 7.

*Benchmarks for indirect opex*

3.33. We are now applying GDN rather than external benchmarks for HR and audit, finance and regulation costs. For HR we have used the ratio of HR full time equivalent employees (FTEs) to total FTEs which we believe better captures the cost drivers than the cost based metric previously used by LECG. We recognise that the previous benchmarking for these activities was leading to an unrealistic level of cost savings due to differences in the nature of the external comparators.

*Difference in business structures*

3.34. There was some concern that our analysis of indirect costs may have been distorted by the different organisational strategies taken by the GDNs. For example NGG has centralised and insourced indirect functions whereas NGN has chosen to outsource most of its activities except strategic and core management activities to UUOL. We have learnt from the experience of normalising the 2005-06 cost data by building additional detailed guidance into a Business Plan Questionnaires. We have also carried out detailed normalisation analysis on 2006-07 to improve the consistency of the data before any benchmarking is applied, and we are not persuaded that further adjustments are needed.

*Marginal costing of SSE services to SGN*

3.35. As noted above, some of the GDNs have raised concerns that the cost allocation methodology used by SSE to allocate costs for some of its services to the two SGN GDNs is a marginal cost approach rather than a fully absorbed cost approach. We consider that the use of marginal costing may distort the benchmarking and create costs targets that are unachievable by other GDNs. We have addressed this by changing the benchmarks from the upper quartile to the second best GDN company group for any activities where SGN is the best performer (all activities apart from property and insurance). This change has been applied to the calculation of allowances for all GDNs other than SGN. SGN already benefit from a significant outperformance reward from allowances being set at the upper quartile and we do not consider it appropriate for SGN to be rewarded further for a relaxation of the benchmarks as a result of the marginal cost pricing approach.

## Impact of the methodology changes

3.36. The overall impact of our proposed changes to the bottom-up analysis is to increase average annual bottom-up allowances for 2008-09 to 2012-13 by 4.5 per cent from £539 million to £563 million.

## Additional areas of costs

3.37. In initial proposals we noted that there were a number of areas of costs where work was still to be completed. This including training and apprentices costs, costs associated with environmental remediation, waste management costs and non-labour regional factors.

### Training and apprentice costs

3.38. As our detailed activity-based benchmarking excludes training and apprentice costs we consider that it is appropriate to make additional allowance so that GDNs can maintain a suitable level of competently trained staff to carry out their activities.

3.39. The GDNs have made significantly different assumptions on apprentice training and learning and development. National Grid and NGN have forecast significant levels of apprentice costs, while SGN and WWU in their BPQ response have made no provision for apprentices.

3.40. The GDNs also jointly commissioned a piece of work by EU Skills looking at the longer term impact of an increasingly ageing workforce which concluded that a further £220 million above the graduate training and recruitment levels submitted in the BPQs would be required over the period 2008-2012 to address the skills shortage in later years. The EU Skills analysis was based on a number of assumptions which we consider are unduly pessimistic such as the rate of loss of skilled staff to the industry, not considering the contractor side of the market and not considering other routes for gaining skilled staff. As such we do not consider it to be a suitable basis for setting allowances.

3.41. Based on the historical and forecast data provided by NGG and NGN we have estimated that an average GDN needs to train 50 apprentices at any time at a cost of £30,000 per apprentice, covering both training and salary costs. This results in an average allowance of £1.5 million per annum.

3.42. In addition we have allowed an average of £0.2 million per annum to cover general learning and development costs. As specific competency training for existing gas engineers is included within the HR benchmarking we do not consider that any further allowance is needed in that area.

3.43. In total this gives £68 million in 2005-06 prices across the GDNs over the price control period which equates to approximately £78 million in outturn prices.

3.44. The training and apprentice costs allowances have been profiled across the GDNs based on the number of full-time employees (FTEs) in each GDN.

**Environmental decontamination**

3.45. We consider that it is appropriate to make an allowance for efficient ongoing decontamination costs consistent with Ofgem's July 2004 open letter[2]. The letter notes "it has in the past been accepted that appropriate allowance should be made for the efficient costs of cleaning up contaminated land occupied for the purposes of the regulated business which are expected to be faced by a licence holder in the period of the control…Ofgem would expect to continue this policy at future reviews".

3.46. The GDNs have provided detailed information on their contaminated sites and potential costs associated with them. We have reviewed their detailed cost forecasts and compared them with the environmental provisions in their accounts and consider their forecasts to be appropriately justified. We consider these costs should be allowed in full and propose to monitor the spend against these amounts through the cost reporting process.

3.47. We consider the cost of any decontamination that is carried out prior to the sale of land should be netted off the sale proceeds. No additional allowance is needed. The July 2004 open letter states that "an adjustment will be made to the RAV five years after disposal to reduce the RAV by the amount of the disposal proceeds. In applying the policy to disposal of (formerly) contaminated land, the adjustment made to the RAV will be consistent with the allocation of decontamination costs. Thus, to the extent decontamination costs have been borne by the company, and not by customers, they should be offset against disposal proceeds in determining the appropriate adjustment to the RAV".

**Waste management**

3.48. Waste management costs are generally associated with the road spoil from street work activities including mains and service replacement, repair, reinforcement and connections activities. GDNs will re-use or recycle significant proportions of their spoil, but large amounts are taken to landfill.

3.49. Our initial proposals only made allowance for waste management costs that were implicit in the assessment of base year costs. This made no allowance for potential increases in costs over time. There are a number of drivers that are increasing waste management costs. Significant ongoing increases in the low and standard rates of landfill tax for 2008-09 to 2012-13 were set out in the 2007 Budget. There have also been increases in landfill charges over recent years as the costs of compliance with waste management regulations increase for landfill operators.

[2] Ofgem open letter, 23 July 2004

3.50. NGN has forecast the lowest level of increase in waste management costs, noting that it can significantly offset rising costs through high levels of recycling. We consider that there is scope for other GDNs to manage costs in the same manner. We have calculated the additional allowances by benchmarking the forecast increase in waste management costs at the upper quartile. We have then applied this rate of increase to the waste management costs that are implicit in benchmarks for repair opex and repex.

3.51. The major uncertainty with regards to waste management costs is whether GDNs will need to reclassify the majority of waste as active (non-hazardous) which would attract higher landfill rates and taxes and lead to significant increases in cost. NGG believes that this will take place while the other GDNs suggest it is a potential risk or do not mention it. We have currently made no allowance for this potential change. NGG has committed to coming forwards with further information, which we will consider, on how likely this change is and when it may occur.

**Additional regional costs**

3.52. The GDNs have put forward a range of special factors for their networks which they suggest should be taken into account in benchmarking costs and setting allowances including:

- regional labour costs;
- additional staff costs to meet the emergency service standards in rural areas;
- additional repair and maintenance costs associated with network length; and
- additional costs of working in London including excavation and traffic management costs.

3.53. We applied adjustments for higher labour costs in London as part of our analysis for initial proposals but made no adjustments for other regional differences. We have considered the arguments put forward for additional costs relating to sparsity in Scotland and WWU and costs of working in London. While there is some merit in the GDNs' arguments on additional costs associated with the emergency service in rural areas we do not consider that they have been well quantified and that there are a number of issues that have not been adequately addressed.

3.54. WWU claims that it has additional operating costs of £6.8m per annum arising from the specific features of its network. It claims that £4.2 million of these costs are related to additional emergency service and indirect costs associated with having a long and narrow network with a low customer density. A further £2.6 million relate to additional repair and maintenance costs associated with additional network length.

3.55. We have reviewed each element of WWU's proposed additional costs for regional factors. We consider that a number of these factors do not require adjustment as they have already been reflected in our benchmarking (for example benchmarks incorporating the number of publicly reported escapes) or the reason for the higher costs has not been adequately justified. We have allowed only fifty per cent of the remaining costs on the basis that their analysis has a number of weaknesses:

- it assesses the additional costs relative to an ideal “square” shape but fails to recognise that none of the other GDN territories approximate to such a shape. Any additional opex should be based on additional costs compared to other GDNs rather than an “ideal” network configuration;
- it assumes that all costs connected with areas outside the perfect square are efficiently incurred and that they are not merely replacing costs that would be incurred if all customers lay within it (for example there might be need for more depots within the square); and
- the location and alignment of the square used is arbitrary and not optimised to cover as much of their territory as possible.

3.56. SGN has put forwards similar arguments to justify additional costs of £1.1 to £1.5 million per annum of operating in Scotland.

3.57. We consider that an adjustment of £2 million per annum for WWU and £1 million per annum for Scotland is appropriate taking account of the above arguments and their weaknesses.

3.58. Both SGN and NGG have put forward additional costs associated with operating in London. NGG claims that there are £2.7 million per annum of additional costs relating to underground congestion and higher reinstatement costs, £0.5 million relating to emergency work profiles in London requiring 24 hour shift patterns in London and £0.3 million relating to the London traffic congestion scheme. Southern claims that there are £4.5 million per annum additional costs for similar reasons.

3.59. We have reviewed the arguments put forward by the GDNs and consider that there are factors which lead to extra costs of working in London over and above labour cost differences. However, some of these factors apply to a lesser extent in other urban areas. Taking this into consideration together with Southern carrying out a smaller proportion of its work within the M25 than London GDN, we consider that an allowance of £1.9 million per annum is appropriate for London and £1.2 million per annum for Southern.

3.60. These additional areas of costs result in the additional annual average opex for each GDN set out in the table below.

**Table 3.4 - Annual average additional opex (£'m 2005-06 prices)**

| Additions | East of England | London | North West | West Midlands | Northern | Scotland | Southern | Wales & West | Total |
|---|---|---|---|---|---|---|---|---|---|
| Aprentice and training costs | 2.1 | 1.2 | 1.6 | 1.1 | 1.6 | 1.7 | 2.5 | 1.7 | 13.6 |
| Waste management | 0.4 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 | 0.5 | 0.2 | 2.4 |
| Environmental remediation | 0.9 | 0.9 | 0.9 | 0.9 | 1.0 | 0.5 | 0.5 | 2.3 | 8.1 |
| Other regional costs | 0.0 | 1.9 | 0.0 | 0.0 | 0.0 | 1.0 | 1.2 | 2.0 | 6.1 |
| Total additions | 3.5 | 4.4 | 2.8 | 2.2 | 2.8 | 3.5 | 4.7 | 6.2 | 30.2 |

## Overall operating costs

### Comparison of top-down and bottom-up benchmarking and uplift on bottom-up allowances

*Initial proposals*

3.61. In initial proposals we based our allowances on disaggregated (bottom-up) benchmarking but highlighted that one of the weaknesses with this approach was that it created a benchmark that was not currently being achieved by any GDN. We addressed this by adjusting the results of the disaggregated benchmarking so that they were consistent with the power of the overall (top-down) opex benchmarking based on the best performing company. This resulted in a 5.6 per cent increase in opex allowances relative to the disaggregated benchmarks.

*GDN responses*

3.62. The GDNs noted that we have adopted the upper quartile approach in our bottom-up analysis as this avoids the reliance on cost information for just one company which may have experienced atypical costs or be unusual in other aspects of its performance. They consider that the same issues apply to the top-down work and logically we should apply the upper quartile approach in that analysis. One GDN noted that the combination of the bottom-up analysis and the top-down frontier means that all companies need to improve on their performance to achieve the proposed allowances in 2008-09. They consider that at least one company should be receiving benefits from outperformance at the beginning of the next price control. One GDN has commissioned work which suggests that the results of the top-down analysis based on the frontier are sensitive to which firms are included. Their consultant notes that the impact of removing one company from the analysis results in a reduction in inefficiencies of between £2 million and £5 million for each GDN.

3.63. The GDNs also highlighted inconsistencies in the rankings between our top-down and bottom-up analysis based on the initial proposals. They consider that the bottom-up methodology is too fragile and is leading to unrealistic levels of opex targets as we have used the upper quartile level of costs for each activity. They believe this leads to the creation of an artificially efficient benchmark GDN.

*Comparison of top-down and bottom-up benchmarking*

3.64. We have compared the results of our updated top-down and the bottom-up benchmarking based on the results of our latest analysis described above. The efficiency rankings of the GDNs under the two types of analysis are set out in the table below. The relative positions of the GDNs under the two approaches are now very similar which we consider supports the robustness of our bottom-up analysis. The same three GDNs are within the top 3 under both approaches although there is a change in the order, West Midlands and East of England are ranked 4 and 5 respectively under both approaches, and the same three GDNs are within the bottom three under both approaches although there is a change in order.

**Table 3.5 - Comparison of efficiency rankings under the top-down and bottom-up analysis**

| GDN | Ranking under top-down | Ranking under bottom-up |
|---|---|---|
| NGN | 1 | 2 |
| Scotland | 2 | 3 |
| Southern | 3 | 1 |
| West Midlands | 4 | 4 |
| East of England | 5 | 5 |
| WWU | 6 | 8 |
| London | 7 | 6 |
| North-West | 8 | 7 |

3.65. In practice our combined approach making use of both the top-down and the bottom-up analysis means that the overall level of allowances for all GDNs is determined by the top-down approach but the bottom-up benchmarking determines the allocation of allowances between GDNs. Given the lack of historical track record we consider that it would be inappropriate to rely purely on the top-down approach as the bottom-up analysis allows us to make use of more data points and consider in more depth the cost drivers underlying each activity.

*Upper quartile analysis*

3.66. We consider that the GDNs have raised a number of strong arguments as to why the uplift on the disaggregated benchmarks should be based on the upper quartile rather than the frontier under the top-down analysis. This is consistent with the approach we have applied in the disaggregated benchmarks and avoids reliance on the data for one company. It is also consistent with the approach we applied in DPRC4.

3.67. We have therefore applied an upper quartile uplift of 6.2 per cent rather than a frontier uplift of 2.3 per cent which is the size of the uplift after all the changes have been made to the bottom up benchmarking.

3.68. With the revised bottom-up analysis and moving to an upper quartile uplift the most efficient GDN receives opex allowances throughout 2008-09 to 2012-13 greater than their 2006-07 actual opex, thus ensuring that they are rewarded for efficiency. The second best performing GDN also received rewards for outperformance for the first four years of the price control period. This is against a background where our overall opex forecasts for all GDNs are reducing as a result of our efficiency assumptions and benchmarking.

## Real price effects and productivity growth

3.69. In initial proposals we assumed 2 per cent real growth in contractors' rates, 1 per cent real growth in earnings and 1 per cent real growth in the cost of materials. The GDNs suggest that our assumptions are insufficient and have put forward a range of evidence to support their views. We have reviewed the GDN data and also analysed additional evidence from other sources. We consider that there is sufficient evidence to support our initial assumptions and have not changed our position. Further details are set out in Appendix 6.

3.70. In initial proposals we assumed ongoing efficiency savings of 2.5 per cent per annum based on our consultant's (Europe Economics) work and an assumption of 1.1 per cent efficiency savings per annum due to comparative competition. The GDNs have raised a range of concerns with this work including the data being out-of-date and it not being possible to rely on the productivity trends in comparator sectors in the Europe Economics work because it benchmarks productivity and input prices relative to UK whole economy averages, ignoring the effect of imports on the UK RPI. The GDNs commissioned additional work from First Economics which proposed an alternative approach for examining the scope for productivity savings. This looks at the contributions different sectors make to trends in the RPI.

3.71. We have considered the arguments raised by the GDNs and commissioned additional work by Reckon LLP including updating the analysis for more recent data. Although this updated work pointed to a wide range of possible conclusions, it did not suggest that our initial proposals assumptions were unreasonable. We have therefore maintained the assumption of 2.5 per cent per annum ongoing efficiencies.

3.72. Further details of our work on real price effects and productivity growth are in Appendix 6.

### Updated opex including the uplifts

**Table 3.6 - Overall opex with uplifts (£'m in 2005-06 prices)**

| Proposed annual average opex | East of England | London | North West | West Midlands | Northern | Scotland | Southern | Wales & West | Total |
|---|---|---|---|---|---|---|---|---|---|
| Initial proposals | 95.7 | 67.0 | 74.0 | 54.0 | 73.0 | 57.0 | 105.5 | 71.9 | 598.0 |
| Updated for 2006-07 actuals and frontier uplift | 88.6 | 61.1 | 70.2 | 53.8 | 72.0 | 58.0 | 100.3 | 70.7 | 574.7 |
| | -7.4% | -8.8% | -5.2% | -0.3% | -1.3% | 1.7% | -4.9% | -1.6% | -3.9% |
| Updated with methodology and assumption changes with additions and frontier uplift | 90.5 | 68.7 | 73.9 | 56.0 | 72.4 | 61.4 | 109.5 | 73.3 | 605.7 |
| | -5.4% | 2.5% | -0.1% | 3.7% | -0.7% | 7.6% | 3.9% | 1.9% | 1.3% |
| Updated with methodology and assumption changes with additions and quartile uplift | 93.9 | 71.2 | 76.7 | 58.1 | 75.1 | 63.6 | 113.6 | 75.9 | 628.0 |
| | -1.9% | 6.2% | 3.6% | 7.6% | 3.0% | 11.5% | 7.7% | 5.6% | 5.0% |

**Carbon monoxide (CO)**

3.73. In initial proposals, we noted that we were considering whether there would be any safety benefits in the GDNs' Emergency Service personnel being required to carry and use carbon monoxide in air measuring equipment during gas investigations.

3.74. We received a wide range of responses to our proposal. While some responses were supportive, a number appear to have interpreted our proposal incorrectly and provided views on the proposal based on such assumptions.

3.75. We commissioned our consultants to assess the direct operational changes and the consequent implications and costs that were likely to result from our proposal. Based on information from the GDNs, the scope of the proposed work, potential implications and costs were wide ranging.

3.76. The report was therefore inconclusive and further assessment is needed on this issue before we decide on the best way forward.

3.77. We therefore propose to hold an industry workshop on this issue in October. This will seek to clarify and inform all parties of what we are considering and the consequences along with reviewing other industry proposals raising the awareness of carbon monoxide. This will then enable us to assess more precisely the cost, benefits and other related issues.

3.78. We anticipate this workshop will primarily be attended by the HSE, GDNs and other GTs, Shippers, Suppliers and any other interested parties who have responded on this issue in our initial proposals.

3.79. The outcome of this workshop will, along with other updated proposal responses, assist us in formulating our position for final proposals.

## Pensions

3.80. Our policy on pensions is broadly unchanged from initial proposals.

3.81. Where interim actuarial valuations are produced, to the extent that these form a full revaluation, as opposed to a roll-forward of a previous valuation, we are minded to accept these for allowances. As such we have updated NGN's allowances for an interim valuation, which increases their pension allowance by £0.7m per annum.

3.82. We also expect a valuation from National Grid Gas. If concluded prior to final proposals, we may update their allowances accordingly. We do not expect this to have a material impact on total allowances.

3.83. We indicated in initial proposals that we would report further on the treatment of any future surplus that may arise under the schemes, either in updated proposals, or as a separate workstream. Since this impacts on all networks, we have decided on the latter, and our current intention is to revisit this issue next year.

3.84. In response to initial proposals, we received a submission from Watson Wyatt on behalf of Centrica which suggested that the assumptions used by the GDNs are significantly more prudent than the average scheme. This was also indicated by ourselves in the fourth consultation document. However, we concluded in initial proposals that, as long as the assumptions appear to be in line with normal actuarial practice, this is likely to balance out over time, since any higher contributions today will increase the solvency of the scheme in the future, and we do not propose to make any adjustment to allowances.

# 4. Capital and replacement expenditure analysis

**Chapter Summary**

This chapter sets out our updated views on a range of policy issues associated with our analysis of the GDNs' forecast capital and replacement expenditure along with our updated proposals for capital and replacement expenditure allowances.

**Question box**

**Question 1:** Do you agree with our revised approach to setting capex and repex allowances and the proposed allowances we have derived using that approach?

## Introduction

4.1. In initial proposals we determined capex and repex allowances for each GDN based on PB Power’s work, together with our own assumptions for regional factors and real input price growth and certain other specific adjustments.

4.2. In June we received details of the GDNs' actual capex and repex for 2006-07. In July we received updated forecasts from each GDN for 2007-08 to 2012-13. We also carried out additional cost visits to each of the GDNs in early August to discuss issues relating to their latest LTS capex forecasts. Over the summer PB Power updated its analysis to take into account the actual costs for 2006-07, revised forecasts and comments from the GDNs.

4.3. Over the last two months we have been considering PB Power's work, their recommendations and policy issues arising from the cost analysis in light of responses to the consultants' draft reports and to initial proposals.

4.4. Our updated proposals on assumptions for real growth in input prices were discussed in chapter 3 and also apply to our analysis of capex and repex in this chapter. The following sections set out the main changes to the GDNs forecast, our revised analysis and updated proposals for capex and repex allowances.

## Updated capex

4.5. Our updated proposals for net capex for the period 2008-09 to 2012-13 are presented in table 4.1 below, which are before the application of the Information Quality Incentive (IQI).

**Table 4.1 – Revised capex by GDN before applying the IQI (£m 2005-06 prices)**

| **INITIAL PROPOSALS** | **NGG** | | | | **NGN** | **SGN** | | **WWU** | |
|---|---|---|---|---|---|---|---|---|---|
| **GDN Normalised Average Net Capex 2008-09 to 2012-13** | **East of England** | **London** | **North West** | **West Midlands** | **Northern** | **Scotland** | **Southern** | **Wales & West** | **Total GDN** |
| LTS & Storage | 10.7 | 16.9 | 11.5 | 1.9 | 15.0 | 15.7 | 42.8 | 22.2 | 136.7 |
| Connections | 9.5 | 6.1 | 4.3 | 3.5 | 9.4 | 10.6 | 9.4 | 9.3 | 62.1 |
| Mains Reinforcement | 2.8 | 2.2 | 2.6 | 2.3 | 4.9 | 7.7 | 14.4 | 6.9 | 43.8 |
| Governors | 0.6 | 1.9 | 3.1 | 0.6 | 1.8 | 3.8 | 10.6 | 1.9 | 24.3 |
| Other Operational | 1.9 | 1.6 | 1.6 | 1.4 | 5.3 | 5.3 | 5.5 | 5.9 | 28.4 |
| Non Operational | 16.5 | 10.4 | 12.0 | 8.6 | 15.7 | 7.2 | 12.4 | 15.2 | 97.8 |
| **Total Net Capex** | **41.9** | **39.0** | **35.2** | **18.4** | **52.1** | **50.2** | **95.0** | **61.4** | **393.1** |
| **Ofgem proposed allowances** | | | | | | | | | |
| LTS & Storage | 9.2 | 12.8 | 10.5 | 1.9 | 10.6 | 12.2 | 28.2 | 16.3 | 101.7 |
| Connections | 6.6 | 4.5 | 2.9 | 2.7 | 7.7 | 8.1 | 7.9 | 6.0 | 46.5 |
| Mains Reinforcement | 3.1 | 1.6 | 2.2 | 2.3 | 4.2 | 6.1 | 11.9 | 6.4 | 37.8 |
| Governors | 0.6 | 1.9 | 3.1 | 0.6 | 1.7 | 3.4 | 9.9 | 1.8 | 22.9 |
| Other Operational | 1.6 | 1.4 | 1.5 | 1.3 | 5.1 | 4.1 | 4.4 | 4.4 | 23.8 |
| Non Operational | 16.4 | 10.3 | 12.0 | 8.6 | 14.3 | 7.3 | 12.6 | 13.9 | 95.4 |
| **Total Net Capex** | **37.5** | **32.6** | **32.1** | **17.5** | **43.7** | **41.3** | **74.9** | **48.7** | **328.2** |

| **UPDATED PROPOSALS** | **NGG** | | | | **NGN** | **SGN** | | **WWU** | |
|---|---|---|---|---|---|---|---|---|---|
| **GDN Normalised Average Net Capex 2008-09 to 2012-13** | **East of England** | **London** | **North West** | **West Midlands** | **Northern** | **Scotland** | **Southern** | **Wales & West** | **Total GDN** |
| LTS & Storage | 10.3 | 27.4 | 15.1 | 2.1 | 15.3 | 15.1 | 32.4 | 27.6 | 145.2 |
| 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 | 15.6 | 102.0 |
| **Total Net Capex** | **43.0** | **48.1** | **38.5** | **18.4** | **52.3** | **44.3** | **83.9** | **68.3** | **396.8** |
| % change to IP BPQ request | 2.6% | 23.3% | 9.6% | 0.1% | 0.4% | -11.7% | -11.7% | 11.3% | 0.9% |
| **Ofgem updated proposals** | | | | | | | | | |
| 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** |
| % change to IP allowances | -2.9% | 27.1% | -15.0% | -2.0% | -3.6% | -13.0% | -5.3% | -1.4% | -2.7% |

## Revised GDN forecasts

4.6. The revised GDN capex forecasts submitted in July were 1 per cent (£18.7 million) higher than those submitted in October last year. Underlying this there have been some significant movements between activities and GDNs.

4.7. NGG's total capex forecast has increased by 10 per cent (£67.9 million). This is primarily driven by changes in LTS capex. London's LTS capex forecast is 63 per cent (£52.6 million) higher due to a forecast increase in contractor costs for the Harefield to Southall pipeline. North West's LTS capex forecast has increased by 31 per cent due to proposing an alternative project to meet its storage requirements.

4.8. SGN's total capex forecast has reduced by 12 per cent (£85 million). This is driven primarily by a 24 per cent (£52 million) reduction in its LTS capex forecast for Southern GDN and a 33 per cent (£33 million) reduction in SGN's total net connections capex forecast.

4.9. NGN's overall capex forecast showed little change to its October 2006 submission. However, movements in their connections workload mix result in a reduction in our proposed net connections capex of 17 per cent (£6.6 million) due to NGN forecasting approximately 10,000 fewer existing housing connections over the five year period.

4.10. WWU's total capex forecast increased by 11 per cent (£34.7 million). This is predominantly driven by a 24 per cent (£27 million) increase in its LTS capex forecast. WWU have stated the increase in cost is for additional PRS rebuilds and capacity upgrades across all three of their LDZs following updated network analysis. We will wish to review these costs along with the LTS pipeline costs following completion of the Offtake Capacity Statement (OCS) process between the GDNs and the NTS in October.

## Updated analysis

**Local Transmission System & Storage Capex**

4.11. Since initial proposals, the GDNs have reviewed their demand forecasts in light of the 2006-07 winter experience and modifications to the demand forecasting methodology. Following the approval of UNC Modification 90, the GDNs were asked to consider the implications of the new interruption regime from 2011-12 for their capex requirements. Our proposed allowances are based on the continuation of the transitional arrangements for capacity booking, plus the impact of UNC Modification 90.

4.12. As part of the work for updated proposals we commissioned PB Power to carry out a detailed review of the need, timing and costs of all major LTS projects planned for construction by the GDNs over the period 2008-09 to 2012-13. In initial proposals PB Power used a generic set of unit costs that have been challenged by a number of GDNs as they did not take into account project specific factors. PB Power has now carried out desktop assessments of pipeline routes and major crossings to derive more robust cost estimates for all of the major projects and to derive updated unit costs to assess the remaining smaller projects. This addresses a number of the key GDN concerns in this area.

4.13. We have proposed the deferral of a number of projects taking into account GDN capacity requirements, diurnal storage requirements, local constraints on the network and the interactions with new arrangements for purchasing interruption. One of the key issues is the interaction with and implication of the NTS and the use of the NTS for diurnal storage. The costs presented in paragraphs 4.15 to 4.26 on LTS capex are all excluding RPEs to enable direct project cost comparison between the GDN costs and Ofgem costs. Within all other tables in this document the LTS capex costs have been adjusted to include Ofgem's RPEs.

4.14. For London network there are two major pipeline projects included within the BPQ:

- Harefield to Southall (18km of 1200mm), 2008-09; and
- Peters Green to South Mimms (26km of 1200mm), 2012-13.

4.15. PB Power considers that NGG has demonstrated a need for a project in 2009-10 to maintain the minimum statutory network pressures. Based on PB Power's work, we consider that the costs of £62.7 million included for this project in London's BPQ return are efficient and we propose to allow this project in full. NGG has since indicated that they are near to completing the final tender process for this project. Tenders are due later in September and early indications are that the project costs are likely to be substantially higher. We will need to review the costs for this project for final proposals taking account of the latest tender information.

4.16. Based on PB Power's recommendations, we consider that the Peters Green to South Mimms project should be deferred by one year to 2013-14 resulting in only £19.3 million of the full £32.1 million being included within the price control period. NGG argues that the project needs to be done earlier to support their repex programme but we are of the view that the NTS can provide the required capacity for the extra year at no additional cost. We will need to discuss the implications of this deferral further with NGG following the completion of the OCS process in October 2007. We may need to revise the allowance in final proposals in light of this work.

4.17. SGN has included three major projects for Southern within its latest BPQ forecasts:

- Barton Stacey to Stoneham Lane (34.5km of 1200mm), 2009-10;
- Barton Stacey NTS offtake, 2009-10; and
- Stoneham Lane pressure reduction installation (PRI), 2009-10.

4.18. These three projects are all part of one large scheme which provides storage to Southern GDN. Our latest view based on detailed work carried out by PB Power is that all three of these projects can be deferred by two years to 2011-12 based on the increased use of diurnal storage via the NTS. While SGN has stated that the projects are not driven by an NTS constraint, their data refers back to an Advantica report written in 2004 which was prior to some additional LTS work that has been carried out in Southern. PB Power considers that some additional capacity has been released back to the NTS following work in the South East LDZ and this could now support South LDZ via an NTS transfer. We will need to undertake further discussions with the NTS and SGN to discuss the capacity transfer and may need to amend our allowances in final proposals in light of this.

4.19. NGG have included £40m to cover alternative storage provisions for the North West GDN. North West GDN have flagged the large percentage of storage they currently take from the NTS with increasing proportions through the plan. The provisions provide storage at a relatively low cost and provides further flexibility to the Network in terms of meeting demand requirements. However, having reviewed the current diurnal storage requirements within North West we are of the view that the proposed investment is not required in the current price control period and hence propose to defer the investment post 2012-13. We will be considering this issue further in discussion with NGG, following completion of the OCS in October, by which time NTS will have provided NGGD with further indications of available capacity. We will also discuss the ability of to control increasing volumes of storage being taken from the NTS for this GDN. This may lead to changes in the capex allowance.

4.20. NGG has included one LTS project for East Midlands LDZ to provide diurnal storage in 2012-13. There is no evidence of constraints on the provision of NTS flex capacity to East Midlands and as such we are proposing to defer this project by one year based on the continued use of NTS storage.

4.21. WWU has raised concerns over the differences between various demand forecasts it has received. There are two sources of demand statements, the NTS and xoserve. Last year all GDN owners chose to use xoserve's demand forecasts in deriving their capex forecasts and OCS requests. This year xoserve reviewed their forecasts based on last year's winter load which resulted in a reduction of 8 per cent to the peak day demand for South West LDZ. The implication of this is potentially a two to three year deferral of almost 50 per cent of WWU's LTS capex. WWU has now chosen to use the NTS demand statements for their OCS requests, resulting in a higher capacity request from the NTS, but has completed its BPQ returns based on last year's xoserve dataset. We are of the view that this overstates demand.

4.22. Five of the LTS capex projects for WWU in South West LDZ are designed primarily to provide diurnal storage capacity rather than to meet a need for transmission capacity. WWU has also indicated that if NTS storage is available then none of these named projects are required in the period up to 2012-13. Based on the revised view of demand and the availability of NTS storage we consider that all five projects should be deferred. This results in £36.1m of expenditure being deferred into the next price control period.

4.23. WWU has included £23.9m of costs in their BPQ for Bancyfelin to Lampeter pipeline. This pipeline is designed to provide storage to the Wales South LDZ. WWU has identified the demand level at which this pipeline is required and based on our view of demand in Wales South and higher pressures available from the NTS this pipeline can be deferred to 2013-14. We have included £1m in 2012-13 for initial expenditure on this project.

4.24. Taking these factors into consideration we propose to defer £59.5 million of WWU's LTS expenditure and allow a project for £6 million to address some of the uncertainties relating to South West demand and storage. We will be considering these issues further in discussion with WWU, following completion of the OCS in October, by which time NTS will have provided WWU with further indications of available capacity. We may need to amend our allowances included in the final proposals in light of this.

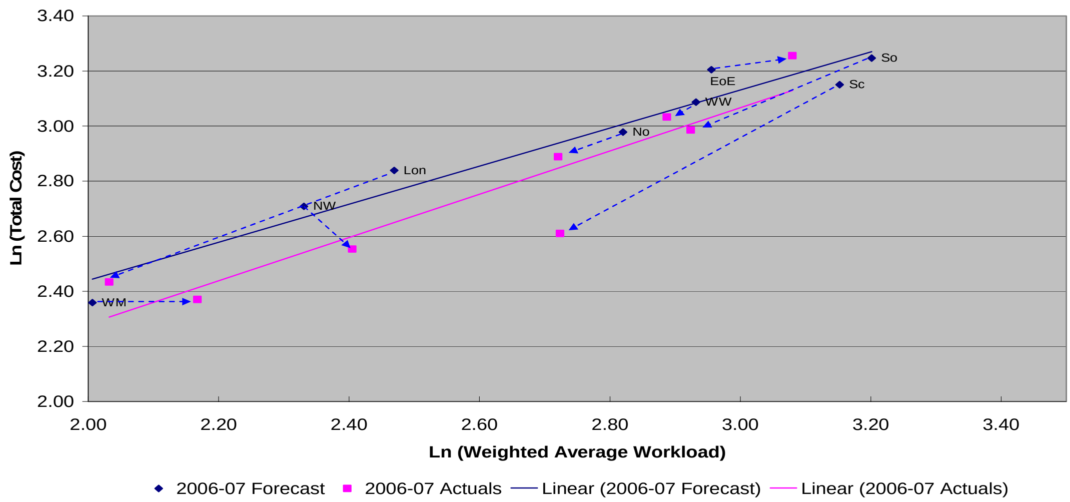
4.25. WWU and NGN have included LTS projects associated with the connection of Uskmouth and Eggborough power stations respectively. We have included costs of £7.6m for Uskmouth power station and £19.8m for Eggborough power station in our forecast LTS capex for WWU and NGN in the anticipation that an ARCA will be signed before the final consultation in February 2007 on the revised licence conditions to implement the new price control. If this is not the case we will remove these costs from our price control allowances. If an ARCA is then signed after this time, we will make an ex-post adjustment to our allowances to include these additional efficient costs.

4.26. NGN has also included a reinforcement pipeline for Keighley to Calder Valley which is proposed for 2012-13. The GDN has stated the sensitivity of network pressures as a main driver for this project. We are of the view that there is a need for this project but the project can be deferred until 2013-14. Preliminary costs have therefore been allowed in this price control.

## Connections

4.27. Our proposals for connections expenditure have reduced by 7 per cent compared to initial proposals. This is principally due to reductions in 2006-07 actual expenditure resulting in lower benchmarks in the regression analysis. The results of the revised regression compared with the regression based on 2006-07 forecasts are shown in figure 4.1 below.

**Figure 4.1 - Comparison of regression based on 2006-07 forecast and actual costs**




4.28. In the update BPQ returns the GDNs were requested to provide specific reinforcement costs and workloads together with general reinforcement due to the similar nature of the work rather than allocating it together with connections. The costs associated with specific reinforcement are now included under reinforcement mains.

4.29. Our updated connections capex is based on the assumption that the GDNs apply a Final Connections Allowance (FCA) for non-domestic customers and the associated costs are included in our capex forecasts and the RAV, rather than recovering these costs separately from the consumers requiring the connection. There is currently a difference in connections charging between NGG and the IDNs based on a difference in legal interpretation. NGG do not apply a FCA and charge non-domestic consumers for the final connection to their network whereas the IDNs provide non-domestic consumers with an allowance for these costs. We are currently discussing the appropriate legal interpretation with the GDNs and the potential policy implication and may need to revise our connections expenditure in light of this in final proposals.

4.30. In response to initial proposals a number of GDN owners raised concerns regarding the productivity assumptions applied to connections, mains reinforcement and repex. We have reviewed these in light of additional information and have revised the productivity assumptions for both mains reinforcement and connections to 1.5 per cent per annum. We consider that a 2 per cent per annum productivity assumption is still appropriate for repex based on the top end of the range of assumptions put forward by the GDNs.

**Mains Reinforcement**

4.31. Our proposed forecast for mains reinforcement has reduced by 25 per cent in total compared to initial proposals. This is principally driven by the benchmarks which we have updated for lower 2006-07 actual capex. This change is partially offset by the transfer of specific reinforcement costs and workloads which were previously captured under connections. We have included £19.9 million for specific reinforcement across all GDNs in our total forecast of £141.6 million.

**Governors**

4.32. Our overall forecast for governors is £7.1 million less than initial proposals. This is primarily driven by the GDN actual governor capex for 2006-07 being 70 per cent (£5.6 million) less than forecast.

**Other operational and non-operational capex**

4.33. We have updated our forecasts for other operational capex to take account of the GDNs' forecasts and PB Power's revised recommendations. Neither set of forecasts has changed significantly.

4.34. A key issue in this area is the potential trade-off between capex and opex allowances. Our updated forecasts allocate £95.0 million (80 per cent) of the total £118.9 million of other operational capex to the IDNs. PB Power considers that this level of expenditure by the IDNs is appropriately justified on the need to replace plant and equipment. NGG has indicated that the lower levels of capex allowances for its GDNs will result in higher opex costs, in particular relating to work management and maintenance. As yet there is no robust information on the scale of this impact. NGG is considering this further and may provide additional evidence. We may need to make a change to our cost allowances to reflect this in final proposals. We would welcome views on this issue.

## Updated repex allowances

4.35. In initial proposals we determined repex allowances for each GDN based on PB Power's work, together with our own assumptions for regional factors and real input price growth and certain other specific adjustments. We have now updated this analysis based on our consultants' latest results and have applied a number of detailed changes to take into account responses to initial proposals.

4.36. Our updated proposals for net repex for the period 2008-09 to 2012-13 are presented in Table 4.2 below. The numbers presented here are before the application of the Information Quality Incentive (IQI).

### Table 4.2 – Updated repex by GDN before application of the IQI (£m 2005-06 prices)

| INITIAL PROPOSALS | NGG | | | | NGN | SGN | | WWU | |
|---|---|---|---|---|---|---|---|---|---|
| **GDN Normalised Average Net Repex 2008-09 to 2012-13** | **East of England** | **London** | **North West** | **West Midlands** | **Northern** | **Scotland** | **Southern** | **Wales & West** | **Total GDN** |
| Mains | 67.8 | 66.4 | 70.3 | 46.9 | 50.7 | 43.9 | 107.4 | 49.5 | 502.9 |
| Services (excl. Riser costs) | 35.0 | 26.5 | 29.0 | 21.5 | 24.3 | 23.7 | 63.3 | 28.1 | 251.4 |
| LTS | 0.0 | 0.0 | 0.0 | 0.0 | 7.4 | 0.1 | 3.7 | 7.3 | 18.5 |
| **Total Net Repex** | **102.8** | **92.9** | **99.3** | **68.4** | **82.4** | **67.6** | **174.3** | **85.0** | **772.7** |
| **Ofgem proposed allowances** | | | | | | | | | |
| Mains | 66.4 | 55.7 | 61.0 | 44.7 | 45.8 | 30.5 | 73.9 | 44.8 | 422.9 |
| Services (excl. Riser costs) | 27.7 | 18.7 | 23.2 | 17.6 | 23.7 | 14.6 | 41.6 | 21.7 | 188.8 |
| LTS | 0.0 | 0.0 | 0.0 | 0.0 | 7.1 | 0.1 | 3.5 | 6.8 | 17.5 |
| **Total Net Repex** | **94.0** | **74.5** | **84.2** | **62.4** | **76.7** | **45.2** | **119.0** | **73.2** | **629.2** |

| UPDATED PROPOSALS | NGG | | | | NGN | SGN | | WWU | |
|---|---|---|---|---|---|---|---|---|---|
| **GDN Normalised 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 | 51.0 | 37.7 | 104.1 | 45.0 | 497.3 |
| 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 | 8.0 | 19.6 |
| **Total Net Repex** | **106.0** | **95.6** | **102.8** | **72.5** | **83.0** | **56.9** | **163.7** | **79.7** | **760.4** |
| % change to IP BPQ request | 3.2% | 2.9% | 3.5% | 6.1% | 0.7% | -15.8% | -6.1% | -6.2% | -1.6% |
| **Ofgem updated proposal** | | | | | | | | | |
| 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** |
| % change to IP allowances | 4.6% | 14.2% | 5.7% | 7.3% | -0.9% | 7.3% | 8.9% | -7.2% | 5.1% |

### Table 4.3 – Revised repex on risers by GDN before application of the IQI (£m 2005-06 prices)

| INITIAL PROPOSALS | NGG | | | | NGN | SGN | | WWU | |
|---|---|---|---|---|---|---|---|---|---|
| GDN Normalised 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 IP Riser costs | 0.8 | 2.9 | 0.9 | 0.5 | 1.3 | 3.7 | 13.5 | 1.2 | **24.8** |
| **Ofgem proposed allowances** | | | | | | | | | |
| IP proposed allowances | 0.8 | 2.9 | 0.9 | 0.5 | 1.3 | 3.7 | 13.5 | 1.2 | **24.8** |

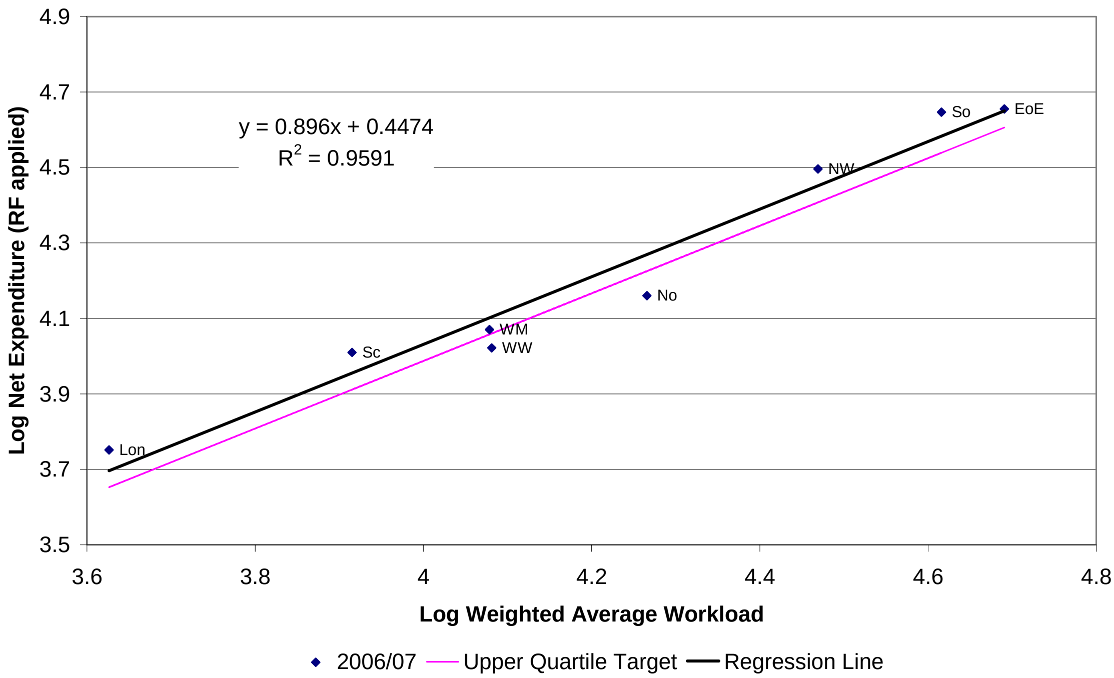
| UPDATED PROPOSALS | NGG | | | | NGN | SGN | | WWU | |
|---|---|---|---|---|---|---|---|---|---|
| GDN Normalised Average Net Repex Riser Costs 2008-09 to 2012-13 | East of England | London | North West | West Midlands | Northern | Scotland | Southern | Wales & West | Total GDN |
| GDN normalised UP Riser costs | 2.5 | 8.4 | 2.2 | 1.6 | 1.3 | 1.3 | 5.7 | 1.0 | **24.1** |
| % change to IP BPQ request | 226.3% | 191.6% | 157.1% | 194.1% | -0.6% | -64.4% | -57.6% | -16.4% | -2.7% |
| **Ofgem proposed allowances** | | | | | | | | | |
| UP proposed allowances | 1.8 | 6.0 | 1.6 | 1.1 | 1.1 | 0.9 | 4.0 | 0.7 | **17.2** |
| % change to IP allowances | 131.1% | 106.5% | 82.1% | 108.3% | -21.1% | -74.8% | -69.9% | -40.8% | -30.6% |

## Updated repex analysis

### Mains and services

4.37. The revised repex regression has changed relatively little from initial proposals as total GDN repex for 2006-07 was broadly in line with forecasts. The revised regression is shown in Figure 4.2 below.

### Figure 4.2 - 2006-07 Repex Regression Analysis (2005-06 prices)



4.38. The main change that we have made to the repex analysis has been to revise the workload driver in the regression analysis to take account of 2006-07 unit costs submitted in the June BPQs rather than 2005 contract costs. The 2006-07 information demonstrates significantly higher unit costs for the larger diameter mains than previously forecast. Since NGG has moved to zonal replacement work, they are forecasting replacement of a higher proportion of larger diameter mains than historically. This has resulted in an increase in their proposed allowances and smaller increases or reductions for the other GDNs.

4.39. In response to initial proposals NGG raised concerns that our proposed adjustments to their workload mix for the diameters of mains installed (downsizing) could lead to failures for part of their network. NGG has argued that this is supported by their latest network analysis.

4.40. We note that NGG is proposing a significant repex programme for medium pressure mains which provides the opportunity to decommission a number of holder sites. As part of the plan for this work they are proposing to downsize and insert a large proportion of these mains and increase operating pressures from 0.5barg to 2.0barg to compensate for the loss of capacity. We consider the insertion of low pressure mains and operation at a higher pressure provides some similar opportunities on the low pressure network. Taking this into consideration together with NGG's comments we consider that it is appropriate to reduce our proposed downsizing adjustments by 50 per cent.

4.41. We have applied a regional adjustment to the repex for London and Southern GDNs to reflect the additional costs of working in London and the South East. These include:

- more extensive traffic management issues – additional requirements to close roads, set up diversions, put in traffic controls in London;
- increased premium time working - where the GDN is refused permission to work in sensitive streets during the normal working day there is a requirement to work evenings, overnight and at weekends. This typically occurs on trunk roads, red routes and busy town centres. They are often required to work 24 hour shift patterns in such changes; and
- notices of direction – where full road reinstatement is imposed by the Highways Authority these costs have to be accommodated. The Highways Authority may prevent the GDN from working on a particularly sensitive route which typically results in route changes and additional length. There may be restrictions on the length of a project that can be carried out which results in additional costs.

4.42. Some of these factors will also apply to a lesser extent in other large metropolitan areas. Taking this into account we have applied a 5 per cent adjustment to Southern's repex and a 7 per cent adjustment to London's repex. The value of this allowance is an additional £26.6m for London and £31.1m for Southern over the five year period.

4.43. PB Power has reviewed the GDNs' repex workload forecasts and diameter mix against the 2005-06 and 2006-07 actuals. Based on PB Power's analysis, we are still proposing a higher abandonment ratio for WWU and NGG than requested. We consider that this is supported by the historical data and comparisons between GDNs.

4.44. SGN are of the view that they are losing out on repex due to the regression methodology using lay rather than abandon lengths. SGN are forecasting a high abandonment ratio of 1:1.1 which we have allowed through the workload forecasts. We have however carried out a sense check of the regression using lengths of mains abandoned rather than lay lengths which suggests that SGN's repex allowances would be lower on that basis than currently proposed.

4.45. Our updated proposals also disallow 62km (20 per cent) of Southern's condition mains replacement. This is additional work following the review by SGN of their unprotected steel mains policy and a comparison between Scotland and Southern networks. We do not consider that 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 network are materially different. Our forecast enables Southern to continue condition based mains replacement at their proposed 2008-09 level throughout the price control period.

**Riser replacement in multiple occupancy building**

4.46. In initial proposals to avoid materially understating the likely repex, we included riser costs based on the GDN forecast workload and costs pending further work for updated proposals.

4.47. NGG significantly increased its forecast BPQ request for risers based on actual costs for London in 2006-07 which were £6.9 million against a budget of £0.9 million. SGN and WWU reduced their forecast riser costs. The GDNs are still completing their riser surveys and there is currently insufficient population data to have a clear picture of future workload requirements. PB Power's analysis suggests that the riser costs should be scaled back by over 50 per cent based on a comparison of actual and historical expenditure. We consider that as the GDNs move from a reactive to proactive programme of riser replacement costs should be significantly less than currently being experienced as the work can be planned and executed in a more efficient manner.

4.48. We consider that significant uncertainty remains both in terms of the riser workload and the appropriate level of unit costs. We have forecast expenditure half way between the GDNs and PB Power view. Over- or under-spends against the allowances for risers will be subject to capex rolling incentives. We will carry out additional work to assess riser costs for final proposals. This may result in revised allowances.

## Information quality incentive

4.49. 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.

The combination of these items ensures that the IQI is incentive compatible, that is, the GDNs' best outcome is to forecast what it expects to spend. The IQI matrix is reproduced below.

**Table 4.4 - 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 |

4.50. It is not possible to ascertain to what extent the incentive has actually impacted the company's forecast. We note that the companies who had the greatest IQI ratio at initial proposals has 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.

4.51. We have applied the IQI in the same way as at initial 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 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. We believe that these two items appropriately reflect the balance between setting challenging targets for the GDNs, and taking into account the arguments of information between us and them. We have therefore not applied the 5 per cent uplift to allowances that was included in DPCR4.

**Table 4.5 - Capex and Repex**

| | 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 | 757.8 | 682.9 | 110.9 | 35% | 8.0 | 186.1 | 514.0 | 700.2 |
| London | 760.9 | 662.1 | 110.9 | 35% | 6.5 | 209.5 | 466.7 | 676.1 |
| North West | 717.8 | 589.1 | 110.9 | 35% | 7.0 | 139.3 | 464.9 | 604.2 |
| West Midlands | 462.6 | 425.9 | 110.9 | 35% | 5.2 | 87.7 | 349.3 | 437.0 |
| Northern | 682.8 | 595.6 | 113.5 | 33% | 4.9 | 215.4 | 398.0 | 613.4 |
| Scotland | 512.5 | 426.9 | 119.1 | 30% | 0.5 | 185.5 | 259.0 | 444.5 |
| Southern | 1,266.8 | 1,022.9 | 119.1 | 30% | 1.1 | 364.9 | 699.3 | 1,064.2 |
| Wales and West | 745.3 | 583.2 | 118.9 | 31% | 0.8 | 247.8 | 359.4 | 607.2 |
| **Total** | **5,906.6** | **4,988.7** | | | **34.0** | **1,636.3** | **3,510.6** | **5,146.9** |

## RAV roll-forward

4.52. 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.

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

| £m 2005-06 prices | Final proposals 1 yr control | Updated proposals main control |
|---|---|---|
| **Total** | **2002-03 to 2006-07** | **2002-03 to 2006-07** |
| **Comparison of actual and allowed spend** | | |
| Total Alllowed 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** |

4.53. For updated proposals related party margins have been removed as part of our accounting adjustment work before the RAV analysis was undertaken.

4.54. 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 |
|---|---|---|---|---|---|---|
| Opening value bf from previous price control | 10,634.7 | | | | | |
| Additions to pre-2002 assets | 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 |

**Table 4.7b – RAV roll forward table, 2008-09 to 2012-13, all GDNs (£m, 2005-06 prices) [4]**

| | 2008-09 | 2009-10 | 2010-11 | 2011-12 | 2012-13 |
|---|---|---|---|---|---|
| Opening value brought forward | 11,716.2 | 12,028.2 | 12,314.1 | 12,530.6 | 12,766.2 |
| Depreciation | -409.7 | -419.0 | -428.0 | -435.6 | -443.8 |
| Net capex additions | 721.7 | 705.0 | 644.5 | 671.1 | 649.3 |
| Disposals | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Closing value | 12,028.2 | 12,314.1 | 12,530.6 | 12,766.2 | 12,971.7 |

**Treatment of property disposals**

4.55. The GDNs have legal ownership of a large physical asset base, including property and land. In the vast majority of cases, this has been funded by consumers, either through inclusion in the opening Regulatory Asset Value of the gas network at privatisation, or through inclusion in the RAV when purchased by the network owner.

4.56. 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. Depending on the location of the land, the net disposal proceeds will not always be positive, as there will be a cost of environmental remediation attached to the land.

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[3] These figures assume that pot 2 and pot 3 expenditure is included in RAV in the year incurred, consistent with the presentation of the RAV roll forward by GDN in appendix 17. The 'closing value' of the RAV in the tables above is equivalent to the 'total closing RAV' presented in our one year control final proposals document.

4.57. Since consumers have funded these assets, consumers should then receive benefit if those assets are disposed for a net positive value. This involves adjusting the net RAV for the disposal proceeds. While the RAV assets may be partly or wholly depreciated, customers should see the benefit of the disposal proceeds, since they funded the assets, regardless of the age of the assets. The only exception would be any assets purchased by the GDNs and not included in the RAV. The result will be a divergence between the value of the RAV and the underlying asset base. However, particularly following the sculpting of RAV in March 2002, it is clear that the RAV cannot be directly reconciled to the GDN asset bases.

4.58. If the GDNs received no benefit from asset disposals, they would have no incentive to dispose of assets at all. Therefore it is appropriate to share the benefit of disposals between the GDN and the customer. We consider it is appropriate to attach an incentive strength comparable to that of other changes to the RAV. Therefore, we will apply a standard rolling incentive mechanism (not the incentive strength on the IQI), 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.

4.59. Where the direct costs include costs incurred by a related party (for example, if the disposals are managed by a specialist property management service within the corporate organisation) the level of cost attributed will need to be demonstrated to be consistent with Ofgem’s approach to related party margins. Any remediation costs which the GDN intends to offset against future disposals proceeds will need to be specifically identified and separated out from the reporting of ongoing environmental costs.

4.60. Any transfer of assets to related parties should be at market value, consistent with the restriction on cross-subsidy within the licence. Given the difficulty of measuring the market value of properties, we will not consider any future transfers of assets to related parties to be disposals for the purposes of adjusting the RAV. Equally, any subsequent disposal of those assets by the related party will be considered to be a disposal of for the purpose of adjusting the RAV. This will be made clear within the cost reporting arrangements.

# 5. Quality of service arrangements

**Chapter Summary**

This chapter sets out our updated proposals for the quality of service arrangements in light of responses to initial proposals and additional BPQ data. We are proposing the same high-level changes as in initial proposals but we consider that there should be a number of revisions to the detail of how these are implemented, including changes to the quality of service allowances.

**Question box**

**Question 1**: Do you agreed with our updated proposals for the quality of service arrangements?

## Introduction

5.1. Initial proposals set out a number of changes to the quality of service arrangements to simplify them and to provide improved protection to consumers. This included:

- removing the overall standards of performance and migrating a number of the obligations to guaranteed standards of performance or licence conditions;
- introducing guaranteed standards of performance for responding to consumer complaints, notifying consumers of planned interruptions and tightening the standard for reinstatement of consumers' premises to 5 days;
- revising the guaranteed standard of performance for supply restoration to include smaller non-domestic consumers and compensation for third-party damage and water ingress incidents;
- introducing new requirements for  GDNs to undertake quarterly consumer satisfaction surveys in respect of connections and gas emergencies;
- gathering additional information from GDNs on the accuracy of pipeline records; and
- introducing a discretionary reward scheme similar to that in place for electricity distribution.

## Responses to initial proposals

5.2. There was general support for rationalising and simplifying the quality of service arrangements in order to improve protection to consumers. Most GDNs supported removing the overall standards, moving a number of the obligations to the licence conditions and introducing new guaranteed standards but had some concerns about the details of these revised arrangements. The GDNs also considered they should be provided with additional funding for any new or tightened obligations.

**Guaranteed standards of performance**

5.3. The GDNs were supportive of the changes to the guaranteed standard for supply restoration to incorporate the third party and water ingress arrangements and include compensation to consumers on other networks, suggesting that this would help ensure all consumers were afforded the same level of protection. They raised a number of practical difficulties regarding situations where supply failure on one network affects consumers on another network. For example, where a supply failure on a GDN's network affects an IGT's consumers, the IGT would need to provide supply point information to the GDNs in sufficient time to enable consumers to be paid within the time limits set by the standards.

5.4. The GDNs note that, while GDNs currently provide emergency services to IGTs, should an IGT decide to have their emergency services provided by another party GDNs may be liable to compensation payments, without any ability to influence restoration times. This needs to be addressed in the development of the standard.

5.5. Some GDNs have argued that there should be a cap on compensation under the reinstatement standard and that the standard should not apply where specialist surfaces are required to be reinstated. One GDN has suggested that failure to meet the reinstatement standard should be measured on a reactive basis when a consumer raises a query.

5.6. The GDNs consider that it is inappropriate to extend the standard for alternative heating and cooking facilities for priority consumers to any consumer that requests them. They note that this is based on a misunderstanding of existing practice. The GDNs provide alternative heating and cooking facilities to other consumers based on an assessment of need at the time.

5.7. The GDNs are concerned that the guaranteed standard for planned interruptions will introduce new requirements to set out the specific dates of the interruption five days in advance and to pay consumers if they interrupt on a different day to that specified. They argue that this may restrict operational efficiency and would be a backward step from the existing service provided an initial notice is given five days before the interruption is expected to start and the GDN then contacts the consumer in a range of ways to discuss when the interruption will take place including by telephone and door-to-door calls.

5.8. A number of the GDNs noted that any new complaint standard should be consistent with the new requirements under the Consumers, Estate Agents and Redress Act 2007.

5.9. None of the GDNs consider Ofgem's proposed approach to setting allowances for the quality of service arrangements appropriate. They have argued that additional costs should be allowed in relation to the reinstatement, planned interruption, alternative heating and cooking and complaints standards as these standards are either new or being tightened. Four non-GDN respondents consider Ofgem's proposed approach to setting allowances for the outputs and quality of service arrangements appropriate.

**Overall standards**

5.10. A number of GDNs are concerned that the 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 as currently drafted would make the standard an absolute requirement. This would provide no protection where failure arises because of extreme circumstances beyond the GDN's control such as severe weather conditions. They note that section 33BA(3) of the Gas Act currently provides the appropriate test: "It shall be the duty of every gas transporter to conduct his business in such a way as can reasonably be expected to lead to his achieving the standards…". They suggest that similar protection should be introduced in the new licence condition. A number of possible solutions have been put forward including introducing:

- an exemption for exceptional circumstances;
- giving the Authority the ability to relax the requirement in the case of exceptional circumstances so that it is not obliged to find a GDN in breach of its licence in such cases; or
- a similar requirement to that set out in the Gas Act.

5.11. The GDNs are concerned that should this obligation be included in the licence, there is the possibility that enforcement action could be taken in respect of both thei licence and their safety case, under the Gas Safety (Management) Regulations 1996, where a similar obligation exists regarding emergency services.

**Consumer satisfaction surveys**

5.12. There was general support for the extension of these surveys but a number of practical issues were raised by GDNs such as which consumers should be covered by the connections and emergency surveys and the required sample size.

**Interruption reporting**

5.13. A number of GDNs have raised concerns with our proposal to introduce minimum levels of performance for the completeness (95 per cent) and accuracy (90 per cent) of GDNs' interruption data which would take effect from 1 April 2009. They note that unplanned interruptions are rare and it is inappropriate to devote more resources to capturing this information. They suggest it is inherently more difficult to capture this information than for electricity distribution as restoring supplies is a manual process.

**Accuracy of pipeline records**

5.14. There were mixed views on the accuracy of pipeline records. Five non-GDN respondents expressed support for the proposals. One non-GDN respondent considered that there should be no financial incentives in this area as effective asset management is an ordinary activity of the GDNs.

5.15. One GDN considers that GDNs should only be assessed on measures over which they have the direct control. This GDN considers it inappropriate for GDNs both to be measured on timeliness with which they digitise records, and to use the absolute number of submissions under Digital Record Asset Policy 4 (DR4s) and Digital Record Asset Policy 8 (DR8s) as a performance metric. Another GDN supports the principles of improving accuracy of pipeline records but considers that the proposals only require reporting on certain criteria which in themselves will not improve accuracy. One GDN considers the proposals sensible and proportionate, and another GDN says the proposed monitoring regime replicates what it will be required to report to HSE.

**Discretionary reward**

5.16. Most respondents supported the development of a discretionary reward scheme in gas distribution, particularly in terms of initiatives to support network extensions, although there were some differing views on what should be included. Two GDNs felt that we should not be overly restrictive in terms of the areas that are covered by the scheme while another felt that although raising awareness of carbon monoxide, network extensions and initiatives to reduce leakage were important areas they should be funded through cost allowances. One GDN felt that it was important to fix the proportions of the discretionary reward that were available to the different categories under the scheme in advance and suggested that raising awareness of gas safety more generally should be included.

**Balanced scorecard**

5.17. There was general support for the development of a balanced scorecard but mixed views on what should be included. One respondent felt that training and safety issues relating to GDN employees and contractors should be included. One GDN respondent felt that it would be inappropriate to include the accuracy of pipeline records or number of reinstatements outside the required timescales. Another agreed with the suggested categories.

## Updated proposals

5.18. We are proposing the same high-level changes to the quality of service arrangements as in initial proposals but we consider there should be a number of revisions to the detail of how these are implemented.

**Guaranteed standards of performance**

5.19. We propose to amend the supply restoration standard to include instances where an interruption originating on one network affects consumers connected to another GDN or IGT network. The GT to whose network the consumer is connected will initially be responsible for making payments to that consumer for any failure to restore supplies. This GT will then be able to claim an exemption if the interruption originated on another GT's network. Where the GT to whose network the consumer is directly connected wishes to claim an exemption on this basis, it has to notify the other GT and provide appropriate details of the number of consumers affected and the length of interruption. The other GT then becomes liable to make the payments.

5.20. The GDNs have raised the issue of what happens if a supply interruption, originates on their network, they make the appropriate repairs on their network before compensation becomes due, but the other GT fails to take appropriate steps to restore the consumer's supplies. They are concerned that they may still be liable to pay the full compensation. We propose that in such instances the consumer should be paid the compensation by the GT on whose network the supply failure originated, but there should be a mechanism for some or all of the compensation to be recovered from the other GT if they are partly or wholly responsible for the failure to meet the standard.

5.21. We propose to introduce a new standard licence condition for GTs consistent with standard condition 20 of the electricity distribution licence which enables distributors who are liable to make payments under the supply restoration standards to recover all or part of those payments from another distributor where that distributor is wholly or partially responsible for the failure to meet the standards. We would welcome views on our proposals regarding this boundary issue.

5.22. We do not consider that it is appropriate to put a cap on the payments made to individual consumers under the reinstatement standard. This would give GTs no incentive to reinstate consumers' properties promptly once the initial period of five days has elapsed. The standard places no requirement on GTs to reinstate non-standard materials within five days. We understand that the normal practice in such cases is to carry out an initial temporary reinstatement and then to reinstate with other permanent materials later. The GDNs are able to meet the requirements of this standard by carrying out the temporary reinstatement within five days. As such no additional exemption is needed. The existing reinstatement standard requires automatic payments on failure rather than consumers needing to claim. We do not consider this should be changed.

5.23. In initial proposals we set out that we intended to extend the provision of alternative heating and cooking facilities during a supply interruption to any consumers who requested it. In light of GDN responses that suggest this may detract from the provision of these services to priority consumers, we now propose to retain the existing scope of the standard. We will include the provision of alternative heating and cooking facilities to other consumers based on an assessment of needs in our best practice guidance.

5.24. We have had a number of discussions with GDNs in working groups on the appropriate form of the planned interruption standard. Taking these responses into account, we propose that GTs should notify consumers at least five working days in advance of a planned supply interruption. The notification should state the period of seven days in which the interruption is expected to commence. If the GT fails to provide this notice or the interruption commences on a day outside this period the GT will be required to pay compensation.

5.25. In line with a number of other standards we propose that the GTs should be able to claim an exemption where the interruption cannot start in this period because of severe weather conditions, industrial action or other exceptional circumstances, provided the GT gives at least one working day's notice. We also propose that where such notice is given, that the GT should provide a revised period during which the interruption is expected to occur. We would welcome views on our proposals for implementing this standard including whether GTs should provide a revised period during which the interruption is expected to occur if they give notice that the interruption will be delayed.

5.26. We propose that the new complaints standard should require GTs to provide a substantive response to written consumer complaints and verbal consumer complaints that are made on a pre-specified consumer contact line. GTs would be required to respond to a complaint within 10 or 20 working days depending on whether a site visit is needed. In addition where a site visit is required the GT will need to notify the consumer of the reason for the delay and stating the period by which a substantive response will be despatched. Where the GT fails any of these obligations it will be required to pay the consumer £20 compensation. We are keeping our proposals for the complaints standard under review in light of work on the Consumer, Estate Agents and Redress Act. This may lead to further changes in final proposals.

5.27. The GT will be required to pay an extra £20 compensation for each additional period of five working days until the substantive response is provided. We do not consider that it would be appropriate to drop this requirement as it would leave no further incentive on the GDNs to response once the initial period of 10/20 working days has elapsed.

5.28. We are considering whether we need to introduce further clarification of what is meant by a substantive response in consultation with the GDN working group. We would welcome views in this area.

**Cost allowances for the quality of service arrangements**

5.29. We have reviewed our cost allowances for the quality of service arrangements in light of the responses to initial proposals and further development of the form of the standards. We have amended our calculations of the likely costs associated with the supply restoration standard and third-party and water ingress arrangements. This is now based on the average amount of compensation paid for each GDN for 2002-03 to 2006-07 without any year's data removed rather than removing outlier years. This has also had the effect or correcting an error which means that the initial proposals costs for interruptions were based on the lower rather than the upper quartile. An ongoing efficiency saving of 2.5 per cent has been applied consistent with other areas of opex. We have added an additional amount to cover GDNs for the costs of making payments in relation to a large incident which does not meet the liability cap. This has been calculated in the same way as for initial proposals.

5.30. We have included additional to reflect tightened requirements under the planned interruption standard and to enable GDNs to establish an Ombudsman scheme for consumer complaints under the Consumer Redress Scheme. This has taken into account information provided by the GDNs on possible costs of this scheme.

5.31. We do not consider that the new consumer complaints guaranteed standard or the tightening of the reinstatement standard to 5 working days justify additional costs. GDNs should already have appropriate arrangements in place for handling consumer complaints as part of their normal operating practices. GDNs are already reinstating the majority of consumers' premises within 5 working days following planned work.

5.32. Our revised allowances for the quality of service arrangements are set out in the table below.

**Table 5.1 Annual average opex for quality of service arrangements for 2008-13 (£m 2005-06 prices)**

| Average annual quality of service opex £m 2005-06 prices | | GSOP1 Compensation | | Additional customer surveys | Planned interruption standard | Consumer Redress | TOTAL |
|---|---|---|---|---|---|---|---|
| | | Unplanned | TPWI | | | | |
| NGG | East of Eng and | 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 |
| | TOTA_ | 0.74 | 1.01 | 0.28 | 0.22 | 0.21 | 2.46 |

**Emergency service standard**

5.33. We propose to move the emergency service standard for attending gas escapes into a licence condition as set out in initial proposals. We do not consider it is appropriate to introduce an exemption to the standard for exceptional circumstances. The standard is measured over a year, which gives the GDN the scope to manage variations in performance. In deciding whether it is appropriate to take any action for breach of these standards and the nature of any such action Ofgem would take account of whether the HSE were taking any steps in relation to the failure and 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.

**Consumer satisfaction surveys**

5.34. We propose to extend the consumer satisfaction surveys to include connections and emergency services as set out in initial proposals. We will be working with the GDNs to address the concerns raised and to finalise the form of the new surveys.

**Interruption reporting**

5.35. As part of the current price control, GDNs were given a total allowance of £5 million (in 2000 prices) to develop improved interruptions reporting. During 2004, it became clear that the information reported by GDNs regarding planned and unplanned interruptions on their networks was not as robust as was expected. Since then there have been improvements in the data but we still consider further improvements are necessary.

5.36. We propose to introduce a licence condition requirement specifying minimum performance levels for the completeness (95 per cent) of data on the number and duration of interruptions and accuracy (90 per cent) of data on number of interruptions are measured. We recognise that there is no secondary data at present with which validate information on the duration of interruptions as it will be entered by staff in the field. Having established these targets we will look to improve them over time subject to cost implications.

**Discretionary reward scheme**

5.37. We propose to implement a discretionary reward scheme as set out in initial proposals. The reward available under the scheme will be up to £4 million per annum.

5.38. The categories to be covered by the scheme will include:

- initiatives which reduce the environmental impact of gas distribution including initiatives which reduce shrinkage but which may not be rewarded through the

shrinkage or environmental incentives and improvements in the measurement of shrinkage;
- initiatives which facilitate network extensions particularly initiatives which increase the affordability of such extensions for fuel poor consumers; and
- schemes to promote gas safety awareness including awareness of carbon monoxide.

5.39. We do not consider that it is appropriate to introduce separate pots of money for each category at this stage but the allocation of any reward should be based on assessment of each of the initiatives that are put forward. The purpose of this scheme is to recognise and reward companies that establish best practice in a particular area rather than to provide funding for any given initiative.

### Balanced score card

5.40. We propose to collate some of the quality of service information in the form of a "balanced score card". Taking account of response to initial proposals, we propose that this scorecard should include:

- the number of unplanned interruptions per 100 customers;
- the accuracy of data for the number of unplanned interruptions;
- the average duration of interruptions;
- the percentage of gas emergencies attended within the prescribed timescales;
- the number of undigitised mains pipeline records;
- the overall results of each of the consumer satisfaction surveys;
- the percentage of complaints responded to within the prescribed timescales; and
- the percentage of reinstatement jobs completed within the prescribed timescales.

5.41. At this stage, we do not intend to aggregate these measures into a single number. We will review this in time, including potential weighting of the measures. We do not consider that it is appropriate to include methane emissions in the balanced score card as they are covered by separate incentives. We have not included the number of error correction reports per km of network as it would not provide clear indication of GDNs performance. For example, a high number on this metric relative to another GDN may not mean that that GDN is performing poorly, it may simply be doing more to correct its asset records.

## Scope of networks

### Private and sub-deduct Networks

5.42. Under section 6A of the Gas Act 1986, the Secretary of State has wide powers to grant class or individual exemptions from the prohibitions under Section 5(1) of the Gas Act 1986 of unlicensed conveyance, shipping or supply of gas. Since 1996, the Secretary of State has made several class and individual exemption orders. The most relevant for the private networks is the Statutory Instrument (SI) 1996 No. 449[5] (Schedule 2A to the Gas Act "Exception to prohibition on unlicensed activities" is also relevant). Under the SI there is an exemption from the requirement to hold a gas transporters licence for licensed suppliers on networks that supply gas that has previously been conveyed to a discrete delivery point on the network of a licensed gas transporter (the "private network" exemption). Second, there is an exemption for networks of "sub-deduct" pipework (as defined by the UNC) that supply gas through secondary meters (the "sub-deduct" exemption). Whereas supply competition does not exist on "private networks" and end users may be un-metered, competition does exist on "sub-deduct" networks and end users are usually metered.

5.43. There are three known major private networks, owned and operated by local authorities, which together with a number of other smaller networks convey gas for supply to circa 80,000 mostly domestic end users. Ownership and maintenance responsibilities including gas safety rest with the local authority.

5.44. There are circa 1,700 sub-deduct networks with approximately 3,300 end users of which approximately 50per cent are domestics and no new sub-deduct arrangements have been developed since 1996. Ownership and maintenance responsibilities including gas safety are not clearly defined on these networks. Legal advice to Ofgem indicates that there is no sufficiently clear stipulation in legislation to render the issue free from real doubt. This uncertainty raises potential concerns with regard to gas safety on these networks and the risks faced by end users and the general public.

5.45. The issues surrounding sub-deduct networks have been extensively discussed with the HSE and the GDNs. While there appears to be general agreement in principal that adoption of some of these sub-deduct networks by GDNs is the preferred option, in practice the GDNs consider that it could create an unacceptable financial risk given the lack of information about the extent and condition of these sub deduct networks.

5.46. The SI is due to lapse in 2011 unless renewed by the Department of Business Enterprise and Regulatory Reform (DBERR). This in conjunction with the expected DBERR policy consultation on private networks provides a clear opportunity for the wider gas industry to make decisions about the adoption of sub-deduct networks by GDNs. Schedule 2A is repealed by the Utilities Act 2000 though the repealing provisions are not yet in force.

5.47. Ofgem recognises that informed decisions on this issue can only be made once there is full information regarding the extent and nature of the assets to be considered for adoption. This could be achieved by requiring the GDNs to undertake

[5] Gas Act 1986 (Exemptions) (No.1) Order 1996.

a full population survey of sub-deduct networks to gather all the technical data relevant to potential adoption. This could establish the investment required to ensure that existing sub deduct pipe work meets the requirements of the Gas Industry Registration Scheme.  Such a survey would also inform the DBERR consultation on the private networks SI.

5.48. While Ofgem is willing to make provision in the GDNs allowed revenue to carry out a full technical survey of sub-deduct networks, at this stage views are sought on;

- the capability/willingness of DNs to conduct a survey;
- the practicalities and challenges involved;
- the timeframe required;
- an estimate of the costs involved per network; or
- alternative methods of resolving this situation.

# 6. Incentives

**Chapter Summary**

This chapter sets out our updated view on the capex rolling incentive and the mains replacement incentive. This chapter also sets out our proposals for the capacity outputs incentive, opex rolling incentive and proposes a revenue driver to deal with the additional costs of the provision of emergency services arising from the loss of metering work.

**Question box**

**Question 1**: Do you agree with our view that an opex rolling incentive is not appropriate?
**Question 2**: Is our approach to capping the expenditure under the mains and services incentive appropriate?
**Question 3**: Is our approach to allocating domestic purge and relight costs to services costs appropriate?
**Question 4**: Do you agree with our approach to the capacity outputs incentive? What are the issues raised by incentivising or not NTS flex capacity?
**Question 5**: Should the volume targets for the flat capacity incentive vary with changes in the calorific value (CV) of gas?
**Question 6**: Is it appropriate to allow a price control re-opener (subject to certain criteria) for any capex spend that may be required following the interruption auctions?
**Question 7**: Is it appropriate to have an adjustment mechanism for the treatment of emergency services costs arising from the loss of metering? If so do you agree with our approach and methodology for the parameters?

## Rolling incentives

### Capex rolling incentives

6.1. We have signalled our support, since the third consultation document, for a capex rolling incentive to provide the GDNs with consistent incentives to make capex efficiency savings over the duration price control, with the power of the incentive to be determined by the application of the IQI (see from paragraph 4.49). The applicable rates are shown in table 6.1 below.

**Table 6.1 - Capex incentive rates by GDN**

| | GDN | Incentive Strength (%) |
|---|---|---|
| NGG | East of England | 35 |
| | London | 35 |
| | North West | 35 |
| | West Midlands | 35 |
| NGN | Northern | 33 |
| SGN | Scotland | 30 |
| | Southern | 30 |
| WWU | Wales and West | 31 |

6.2. The incentive exposes GDNs to a pre-determined proportion of any overspend (in the range of 30 to 35 per cent as set out in the table above). This has a number of advantages over the approach adopted in the previous review. As well as providing transparent incentives to spend efficiently, it removes uncertainty over how over/ under spend will be treated at the next review. We do not therefore intend to carry out the detailed ex post review of capex efficiency that we did to evaluate the treatment of the overspend in the 2002-07 price control. However, we reserve the right to disallow any expenditure that is demonstrably wasteful or unnecessary, as well as making adjustments for items such as related party margins.

6.3. In the second consultation document we considered the options for the capex incentives for the one year control for 2007-08, which included applying the capex incentive from the five year control to any over/ underspend. We consider that this is the appropriate approach and so the incentive rates set out in table 6.1 above will be applicable to that period, too.

**Opex rolling incentives**

6.4. A conventional RPI-X price control maintains strong incentives, but these are perceived to weaken through the price control. This is because a GDN expects that any cost savings it makes during the price control will be taken into account when allowances are reset for the subsequent price control. This can distort efficient decision-making by putting a premium on making savings in the first or the last year of a price control. One potential solution to this problem of periodicity is to have an opex rolling incentive, so that GDNs get to keep the value of any cost savings for 5 years through additional allowances in the next price control.

6.5. 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. An opex roller applied on top of this would be effectively double-counting the savings.

6.6. 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.

6.7. On balance we are proposing not to implement an opex rolling incentive for this price control. Further details of our analysis supporting this decision are contained in appendix 10 which sets out the impact assessment for the opex rolling incentive. 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 (IFI) for gas distribution (see paragraphs 7.47 to 7.52).

## Mains and services replacement incentive

6.8. In initial proposals we proposed retaining the current form of the mains replacement incentive, but refining it by including 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 including unit costs for three additional larger pipe diameter sizes, as set out in initial proposals. There was broad support from respondents for this approach.

6.9. 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 6.1 above). This will apply symmetrically. However, in the last price control GDNs were still required to keep within an overall expenditure cap, which was simply the aggregate of the five year forecast of expenditure.

6.10. There are a number of options for resetting the incentive cap. One option is to maintain the cap at the aggregate of the five year forecast of expenditure. However, if a GDN's actual five year workload is as forecast but its unit cost is higher than forecast it would be exposed to the full cost of the overspend. This would not be consistent with the principles underlying the capex rolling incentive, which also applies to other repex. An uplift to the aggregate of the five year forecast of expenditure would simply allow a GDN to increase its workload beyond that set out in our assessment with no penalty, which is also inconsistent with the principles of the capex rolling incentive. If we consider that the capex incentive strength is sufficient to encourage GDNs to minimise unit costs, an alternative option is to cap the mains and services replacement workload so that it cannot exceed the five year forecast. Our concern with this approach is that if a GDN increases its larger diameter workload and reduces its smaller diameter workload without a net change to the overall workload this could result in significantly higher costs to consumers. We consider that a workload incentive with a cap on diameter sizes would be unnecessarily complex and undermine the flexibility provided by the mechanism.

6.11. Our preferred option is to set the cap 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. Examples of how the cap would work in conjunction with the mains and services incentive (MSRA) are shown in table 6.2 below.

**Table 6.2 - Examples of the mains and services cap (five year totals)**

| | Mains and services cap<br><br>[A] | Mains and services matrix<br><br>[B] | Outturn costs<br><br>[C] | Mains and services incentive<br><br>[B]+(([C]-[B ])*0.65) | Costs subject to capex rolling incentive<br><br>((B) – (A))*0.35 |
|---|---|---|---|---|---|
| 1 | 500 | 500 | 600 | 565 | 0 |
| 2 | 500 | 625 | 625 | 625 | 43.75 |
| 3 | 500 | 625 | 750 | 706.25 | 43.75 |

6.12. In table 6.2 we have assumed an incentive rate of 35 per cent. Under the incentive the mains and services matrix is adjusted annually for higher workload but not for higher unit costs. Then the outturn is compared to the matrix and any overspend (which must be due to unit cost variances) is subject to the incentive, with the GDN bearing 35per cent of the overspend.

6.13. The first example shows a GDN that has higher unit costs than forecast but has delivered the forecast workload resulting in an overspend of 100. Under the mains and services incentive it is exposed to 35 per cent of the overspend so under the incentive its revenues are 565. Although it has exceeded the cap it has already been fully penalised for this under the MSRA mechanism and there are no further adjustments to be made.

6.14. In example 2 the GDN's unit costs are as forecast but it has a higher workload than forecast. The mains and services matrix increases to take account of the increase in workload and the incentive revenue increases by the full amount of the cost of the overspend i.e. by 125 to 625. None of the overspend has incurred any penalties under the MSRA. Therefore, the GDN is exposed to costs of 43.25 which is 35 per cent of the 125 overspend.

6.15. In example 3 both the GDN's workload and unit costs are higher than forecast. The mains and services matrix adjusts the incentive revenues to take account of the overspend against the workload, of 125, but not the overspend against unit costs. The MSRA has already exposed the GDN to 35 per cent of its overspend on the unit costs, so the application of the cap exposes the GDNs to 35 per cent of the costs associated with the workload overspend.

6.16. Appendix 15 sets out the mains and services matrices for the incentive by GDN. This section explains our methodology for allocating domestic purge and relight costs to the domestic services costs in the matrices. Purge and relight costs have been reported separately by GDNs in the BPQs. At least one purge and relight is required for each service. However, due to the contracts that GDNs have with their contractors for the provision of services there has not been a clear methodology for allocating purge and relight costs to each of the separate service cost areas. Scotia Gas Networks is the exception to this. In their submissions they reported one purge and relight for each:

- relaid service associated with mains replacement;
- relaid service not associated with mains replacement (bulk relays);
- service relaid after escape,
- service test and transfer to another main; and
- service relay arising from repositioning a domestic meter.

6.17. In appendix 15 we have based our methodology for allocating purge and relight costs on this approach for all of the GDNs. Where purge and relight volumes are greater or less than the aggregate volume of these services we have scaled up or down the purge and relight volumes accordingly and scaled the costs consistently for the two types of domestic services costs associated with the mains and services incentive - relaid services associated with mains replacement and service test and transfer to another main. We are seeking views on whether this is the appropriate methodology to use for allocating purge and relight costs to domestic services.

## Capacity outputs incentives

6.18. Following GDN sales, the GDNs have to book exit capacity from the NTS, which is then directly paid for by shippers. Absent any specific mechanism the GDNs would have no financial incentive not to overbook capacity. The capacity outputs incentive for the transitional offtake period expires on 30 September 2011. As part of final proposals, it will be necessary for Ofgem to implement a capacity outputs incentive covering the period 1 October 2011 – 31 March 2013.

6.19. Setting a capacity outputs incentive for the period beyond 30 September 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 interruptible capacity auctions. The first interruptible rights associated with the 2008 interruptible capacity tender come into effect on 1 October 2011, and it is important that the incentive is compatible with the new interruption regime.

### Interruptions

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

6.21. By allowing customers to reveal the value they place on interruptible capacity the reformed arrangements should enable the GDNs to make better tradeoffs between contracting for interruption versus reinforcing their own pipeline network and booking incremental NTS flat capacity. However, moving from an administered set of interruption arrangements to a market allocation of interruptible capacity carries some uncertainty. At the moment GDNs know what level of demand there is for interruptible rights at the level of the current transportation charges capacity discount. However, in advance of the first round of interruptible capacity auctions, absent any information about the elasticity of this 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.

6.22. It will be in the interests of the generality of customers for GDNs to book interruptible capacity up to the point at which it becomes more economically efficient for the GDN to invest in pipeline reinforcement. Where there is no reinforcement cost associated with making a specific customer firm this would imply a low price for interruptible capacity. At locational network constraints it is implicit that there would be a reinforcement cost associated with providing firm capacity and so it may be efficient for GDNs to pay a higher price for interruptible capacity in these locations. We consider that it is appropriate for the different market circumstances under which the GDNs might book interruptible capacity to be reflected in the value of the interruptible capacity allowance.

6.23. The GDNs tend to require interruptible capacity 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 consider that the generic interruptible capacity that the GDNs may need to manage peak day demand can be traded to some extent with NTS flat capacity needs. More detail on the NTS flat capacity incentive is outlined in the section below, but given that we propose to set it at a level which assumes all loads other than NSLs are firm, we do not currently propose to set another allowance for generic interruption within the interruptible capacity incentive. This does not imply that we consider that the GDNs will not seek to contract for generic interruptible capacity, rather that we consider it appropriate to incentivise the GDNs to make efficient tradeoffs where possible between contracting for interruptible capacity on their own networks and booking incremental flat capacity from the NTS.

6.24. We propose to set the interruptible capacity incentive at a level which incentivises the GDNs to contract for interruption with NSL supply points up to the point at which it becomes more efficient to reinforce the network to make them firm. This equates to the discounted level of the GDNs' exposure to the cost of the reinforcement projects necessary to remove locational constraints on their networks. The value of this incentive will vary by GDN according to how constrained their network is. From the GDNs BPQ responses, and through a series of bilateral meetings conducted in December 2006, Ofgem is aware of the size and nature of these locational constraints. We intend to review the investment costs associated with these constraints in more detail, and propose to consult on the interruption incentive values via a separate consultation in October. Based on 1 April 2006 GDN transportation charges, the total value of the capacity charges discount received by interruptible customers across all distribution networks is in the region of £40m per annum. We anticipate that the value of the incentive using the proposed methodology would be less than this amount and so we would expect the net effect to be a reduction in the level of transportation charges for the generality of customers.

6.25. The methodology outlined above reflects a concern to minimise the potential for inefficient capex outcomes as a consequence of the first interruptible capacity auctions, but given that non NSL interruptible capacity can be traded to some extent with NTS flat capacity, we also consider that it is important that the interruption incentive and NTS flat capacity incentive have equally powered sharing factors and caps and collars. We consider that 100per cent sharing factors promote the most efficient tradeoffs and so we propose to apply this level of sharing factor to both the interruption and flat capacity incentive. It is also our view that in this context wide caps and collars work better than very tight ones, but since we recognise the uncertainty associated with the first round of interruptible capacity auctions we propose to set these at the 10per cent level. We seek views on the appropriateness of these parameters.

6.26. We consider that the incentive proposal provides GDNs with a degree of flexibility over the payments they make for interruptible capacity, but we do not consider that it should be necessary for the GDNs to pay all customers on locational constraints up to the full discounted level of their exposure to the costs of the reinforcement. Under the existing interruption arrangements NSL supply points are more likely to be interrupted than other interruptible supply points. Consequently we would expect that they would be among the most prepared to be interrupted and, as a result of the necessary alternative fuel arrangements that they already have in place, relative to other customers will have a lower marginal cost of being interrupted. Customers in this category who find it attractive to be interruptible will be reluctant to put their interruptible status at risk by bidding excessive amounts at auction. This combined with a degree of substitutability between interruptible loads is likely to put downward pressure on the price of interruption.

**Flat capacity**

6.27. We intend 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 NSLs, are firm. If the GDNs consider that they may be able to make an incentive saving on NTS flat capacity bookings by paying for non-NSL interruptible capacity then we would expect them to trade these payments off against outperformance of the interruptible capacity incentive.

6.28. The GDNs' own data will inform the level at which the NTS flat volume target will be set, so we consider that the GDNs' ability to control the level of their exit capacity bookings is sufficient for them to be exposed to a reasonably high degree of risk relative to the target. For this reason, consistent with our proposals on the interruption incentive, we propose that the NTS flat capacity incentive should retain its 100 per cent sharing factor. There is currently a 7.5 per cent cap and collar on the GDNs exposure against target on this incentive, but to ensure parity with our proposals for the interruption incentive, and to reflect what we consider is a relatively limited risk to the GDNs associated with this incentive, we propose to change this to 10 per cent, but as with the interruption incentive we seek views on the appropriateness of these parameters. We are not in a position to consult on the values of the NTS flat capacity targets at this stage, but following completion of the OCS (offtake capacity statement) process in late September, we will be inviting the GDNs to resubmit their exit capacity forecasts based on the assumption that all customers other than NSLs are firm. We intend to consult separately on the incentive values in mid October 2007. The timetable for this consultation is set out in Chapter 11.

6.29. One of the perceived shortcomings of the transitional incentive relates to the fact that the NTS exit capacity volume targets are not set to reflect potential changes in the calorific value (CV) of gas. Changes in CV can impact on the volumes of gas that the GDNs need to book from the NTS, which can in turn affect their performance against the incentive in a manner which is beyond their control. We seek views on whether volume targets should be adjusted for changes in the calorific value of gas.

**Flex capacity**

6.30. On 5 April 2007 Ofgem directed Mod proposal 116V 'Enduring offtake reform' for implementation, 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. A significant feature of the enduring offtake arrangements as proposed in Mod 116V relates to the market allocation of a separate NTS flexibility capacity product. In locations where NTS flexibility could be considered scarce, a market allocation of the product would ensure that whoever valued it most would be able to secure it. This contrasts with the transitional offtake arrangements where the release of flexibility capacity is effectively administered by the NTS. In developing our thinking on how the flex capacity incentive should be set, we are of the view that it is worth considering how the different offtake proposals might impact on the price paid for the NTS flex product.

6.31. Ofgem is aware of NGG's assessment that 22 mcmd of flexibility capability is currently available on the NTS. It is estimated that only 14 mcmd of this flexibility is currently used, and so it is generally considered at an aggregate level that there is no scarcity of the service. Under the transitional exit capacity arrangements GDNs book flat and flex capacity from the NTS, and GDN Shippers pay the NTS directly for the NTS exit capacity provided. Because NTS flex capacity is produced as a by-product of investing for flat capacity, and the NTS incurs no incremental cost in providing it, the NTS does not charge anything for its use. This means that under the transitional arrangements the NTS exit capacity charges faced by shippers are driven solely by the GDNs' flat capacity bookings.

6.32. We would not conclude from the industry consensus that there is no current scarcity of flex that a scarcity of the service could not and may not develop in the future. Since neither GDNs nor shippers are charged for using flex, absent any incentive on the GDNs to book flex efficiently, one view would be that a scarcity of flex could arise as a result of it being booked unnecessarily. Given that the GDNs have an obligation under the Gas Act to develop and manage their pipeline system in an efficient manner we would consider that the propensity for GDNs to book flex inefficiently would be relatively limited in the short term, although such a trend may be more likely to develop incrementally over a longer period. Alternatively, since the clear view expressed by industry during the consultation on the offtake proposals and in the subsequent appeal was that there is no shortage of flex capacity and that demand for the product is not anticipated to increase significantly, a different view would be that it is not necessary to constrain GDNs' decisions in respect of flex by incentivising their flex bookings at all.

6.33. If a market allocation of NTS flex was implemented as part of enduring offtake reform, and regional constraints of flex developed, it is likely that parties would be charged for acquisition of the product in these locations. In this situation whether shippers were paying for the flex that GDNs had booked, or GDNs were paying for it directly, it is likely that we would consider it appropriate to incentivise the GDNs to book it efficiently. Nevertheless, we would note that if the availability of NTS flex capacity continues to be unconstrained, there is no reason to believe that participants should pay anything for it whether it is allocated via a market mechanism or administered by the NTS. Taking a pragmatic view on whether this situation is likely to change significantly within the relatively short price control period to which this incentive would apply, we seek views on whether there is a need to incentivise GDNs bookings of flex at this stage.

6.34. The table below summarises the transitional capacity output incentive scheme, which applies up to 30 September 2011, and the capacity output incentive proposal for the period 1 October 2011 – 30 March 2013.

**Table 6.3 - Summary of transitional and proposed capacity output incentives**

| | 1 April 2008 - 30 Sept 2011 | | 1 Oct 2011 - 31 March 2013 | |
|---|---|---|---|---|
| | Parameters | Value | Parameters | Value |
| NTS Flat capacity | 7.5% or £5m Cap and collar 100% sharing factor | Volume target based on GDN/NTS forecast | 100% sharing factors, caps/collars to be confirmed | Based on forecast of volumes required to support all non-NSLs as firm |
| NTS Flex capacity | | Volume target based on GDN/NTS forecast | For consultation | For consultation |
| GDN interruption | | Target currently zero | 100% sharing factors caps/collars to be confirmed | Equivalent to GDNs exposure to discounted reinforcement cost of NSLs |

**Capex reopener**

6.35. We consider that there are good reasons why it will be attractive for existing interruptible supply points to participate in the interruptible capacity auctions:-

- the potential for significant increase in interruptible payment;
- more flexible contracting options will be available; and
- the risk of losing out on any interruptible payments in the future if they are made firm.

Until the outcome of the auctions, though, the GDNs will not have any certainty regarding the full extent of the capital expenditure they may have to undertake in terms of locational constraint reinforcement projects.

6.36. The GDNs' exposure to these additional capex requirements is limited by the application of the capex roller (see table 6.1 for the applicable rates). It may be the case that since we are proposing to set the GDNs' interruption incentive at the level equivalent to the discounted level of their exposure to locational constraint reinforcement projects, they will be able to fund the initial shortfall in capex from this allowance. Nevertheless, we are aware that the different powers of the capex roller incentive and the proposed interruption opex incentive have the potential to confuse this trade off for the GDN. We are therefore seeking views on whether a capex re-opener provision would be a more appropriate mechanism here. This would be based on specific criteria, including evidence that the GDN had made all efforts to engage the customers in the auction process, and demonstration that the size of customers' bids for interruption made reinforcement the most efficient option. Any additional capex agreed under the capex roller mechanism would also require a complementary reduction in the size of the interruption opex allowance. We intend to consult in October on the specific parameters of a possible capex reopener.

## The loss of meter work revenue driver

6.37. The GDNs are obliged to provide emergency services to customers. A consequence of the number of staff the GDNs need to ensure they are able to meet their obligation to respond to an emergency within one hour is that many of those staff will be unused or unproductive at any point in time. The GDNs mitigate the costs of providing emergency service by finding additional work (infill work) for the emergency service staff to carry out. Only work that can be carried out to a flexible schedule and uses a similar skill set is suitable for this infill work. The main infill work has historically been providing metering services to meter asset managers (MAMs). Metering service work is a competitive market, and as a result the GDNs are not guaranteed this work. Indeed, they are all forecasting that they will lose most if not all of it over the next few years. They argue that the MAMs require better service levels than they can deliver by using emergency service staff for whom this work must necessarily take second priority.

6.38. GDNs have forecast that the costs of providing the emergency service (which is remunerated through the price control) will rise over the next price control period since the amount of unproductive time will increase. Additionally the metering work also absorbed an element of indirect costs that would have to be absorbed by the price control activities, leading to a further increase in costs. The incremental costs do not rise immediately with loss of metering, because the metering services are provided by a mix of emergency service staff and contract labour. The latter can be released (or reallocated to other areas of work) if there is not sufficient metering work, and so a certain amount of loss of meterwork can be absorbed without significantly impacting the cost of providing the emergency service. Beyond this point (the “tipping point”) costs rise significantly.

6.39. We accept the GDNs’ concerns that if we simply provide allowances to cover the costs of providing the emergency service under the status quo (these costs are included in the opex allowances), they are exposed to significant incremental costs should they fail to retain metering contracts. On the other hand we do not want customers to pay for potential windfall gains if we make an ex ante allowance based on GDNs’ projections of metering work loss but they then retain the contracts or lose metering work at a slower rate than forecast. We also consider that GDNs should have incentives to seek out opportunities for other types of infill work that staff can undertake in between emergency work. Examples of work that staff could undertake and leave at short notice includes risk, leakage and high rise surveys and downloading metering data from data loggers.

6.40. NGG has proposed that GDNs should be given an allowance based on the GDNs’ BPQ forecast of emergency service costs (which includes their assumptions of the extent of loss of metering related revenues and increased redundancy of staff). NGG also proposes adjustment to the allowance, subject to sharing factors of 75 per cent for customers and 25 per cent for the GDNs, depending on the amount of metering related activities actually undertaken compared to the forecast. The disadvantages of a sharing factor are that it weakens incentives, and also that we have to ringfence actual emergency service costs in order to calculate the amount to be shared.

6.41. We are proposing a revenue driver, which will increase GDN revenues based on an average the unit cost of each incremental metering job lost if the GDNs do lose metering work in excess of the volume at the tipping point. The tipping point takes account of the fact that an initial reduction in meter work should not materially impact the workload of the emergency service staff, and therefore not increase the costs associated with the provision of emergency services. This is supported by the GDN forecasts. Our initial view of the appropriate incentive parameters is set out in the table below.

**Table 6.4: Parameters for the loss of meter work revenue driver**

| | GDN | Tipping point (percentage of 2005-06 meter work jobs) | Tipping point (Number of metering jobs losses above which the revenue driver would not apply) | Revenue Driver (£) (Unit cost per job - post tipping point) |
|---|---|---|---|---|
| NGG | East of England | 49% | 204,762 | 26.54 |
| | London | 50% | 100,511 | 30.53 |
| | North West | 51% | 106,252 | 31.43 |
| | West Midlands | 59% | 106,306 | 29.52 |
| NGN | Northern | 39% | 166,615 | 21.60 |
| SGN | Scotland | 42% | 214,795 | 11.60 |
| | Southern | 31% | 305,614 | 19.09 |
| WWU | Wales and West | 44% | 147,471 | 21.72 |

6.42. We have calculated the revenue driver by taking the average GDN forecast for the increase in waiting time for emergency service staff caused by the expected loss of metering up to 2012-13 and converted it to the number of incremental emergency full time equivalent (FTE) staff that would be required based on the current emergency jobs and the increase in waiting time. We compared this with the incremental FTE figures forecast by each GDN, and found significant differences in some cases. It is not clear precisely what the drivers of these differences are, but we recognise that there may be valid reasons why the figures should differ across GDNs, and so have based our proposals on an assumption that the required number of incremental FTEs is 50per cent of the GDNs' own figures and 50 per cent of the number calculated by the methodology above. We then calculated the cost of the incremental FTE staff using a benchmark cost of the emergency service per FTE emergency staff adjusted for regional factors.

6.43. We have carried out an assessment of the tipping point as implied by the GDNs' forecasts of additional costs, at the point where the incremental costs of the expected loss of metering increases significantly. As with the forecasts of incremental FTEs, there was quite a difference across GDNs. While we can see that there are some factors that might help explain this differential, including the extent to which meter work is carried out by dedicated metering staff or contractors, this does not seem to fully explain the variation. We therefore took 50 per cent of the GDNs own tipping point and 50 per cent of the average across all GDNs (expressed as an percentage of 2005/06 metering volumes, since GDNs have varying levels of absolute meter work). This gave us the proposed tipping points shown in table 6.4.

6.44. The tipping point and the total incremental cost allowed us to derive a unit cost for metering jobs lost beyond the tipping point. This is shown the right-hand column of table 6.4. To give an example of how the revenue driver would work; if for a given year, the East of England GDN carried out 154,672 metering jobs, it would be entitled to an additional; allowance of (204,672-154,672)*26.54 = £1,327,000. If on the other hand it carried out 205,000 metering jobs it would not get any additional allowance as this is above the tipping point.

6.45. We have excluded the costs associated with indirect costs and work management costs but include an allowance for incremental plant per FTE. We would expect that, in the event of a substantial loss of meterwork, these costs should be reduced over time due to the lower levels of activity. We have currently not rolled forward the incremental cost on an annual basis to reflect our views on real price effects (1 per cent pa, if we assume the staff are directly employed) and productivity (2.5 per cent pa). We welcome views on whether we should adjust our unit cost proposals for any of these factors.

6.46. This approach assumes that none of the resources currently involved in meter work could be reallocated to other activities, beyond the tipping point. As discussed above we consider that some reallocation is likely to be possible, which would result in a reduction in the unit costs in the table above. We welcome views on whether such infill activity for the emergency staff is likely to be feasible, and what impact this is likely to have on the marginal unit costs above.

6.47. A refinement to this proposal, if we were concerned to minimise the chance of windfall gains and losses from the incentive would be to introduce a sharing factor so that GDNs only bore a proportion of any losses or kept the same proportion of any gains made after application of the revenue driver. This would be a similar solution to that proposed by NGG (although their version presumed an ex ante allowance for projected metering loss). For the reasons set out above we do not recommend sharing factors.

6.48. The cost to consumers of the revenue driver depends of course on the outcome of the re-tendering of the metering contracts. However, if metering was lost as forecast by the GDNs, we estimate it would cost £92m across all GDNs and across the five years.

# 7. Sustainable development

**Chapter Summary**

This chapter sets out our updated views on the shrinkage incentive - which we consider should be complemented with an environmental emissions incentive, network extensions and the innovation funding incentive.

**Question box**

**Question 1**: Is it appropriate to roll forward the existing shrinkage incentive and if so do you consider the leakage volumes appropriate?
**Question 2**: Is the gas reference price formula appropriate?
**Question 3**: Should Ofgem establish a new incentive to target harmful environmental emissions?
**Question 4**: Do you support the design of the environmental incentive and its parameters?
**Question 5**: Are the strength and baselines for the incentive appropriate?
**Question 6**: Are the cap and collar arrangements appropriate?
**Question 7:** Is it appropriate to introduce a mechanism to address periodicity of investment?
**Question 8**: Are the leakage model and governance arrangements appropriate?

## Shrinkage arrangements and Environmental Emissions

### Background

7.1. The GDNs procure gas for shrinkage, which includes leakage, own use gas and theft. For the one year control Ofgem based allowed shrinkage revenue on ex ante shrinkage factors and a gas price formula linking allowed revenue to three month-ahead gas prices. In initial proposals we suggested broadly rolling forward the shrinkage incentive arrangements but modifying the gas price calculation.

### Determination of the volume of shrinkage gas

7.2. We have taken into account the GDNs' forecasts, our consultant's views and performed our own analysis of shrinkage volumes as set out in appendix 14. Table 7.1 shows our forecast of shrinkage volumes over the price control period.

7.3. Our forecast shows an overall decrease of 2 per cent in shrinkage volumes over the price control period, from 4224 GWh to 4141 GWh, which is primarily due to replacement of metallic mains with PE. This reduction is partially offset by increases to average system pressure, which results in higher leakage from a given set of pipes, and by demand growth, which results in higher levels of theft and own use gas consumption.

**Table 7.1 - Shrinkage volumes forecasts**

| Shrinkage volume (GWh) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | 2007-08 | 2008-09 | 2009-10 | 2010-11 | 2011-12 | 2012-13 |
| Owner | LDZ | Total | Total | Total | Total | Total | Total |
| NGG | East Midlands | 410 | 409 | 409 | 410 | 414 | 413 |
| | East Anglia | 294 | 293 | 293 | 294 | 296 | 296 |
| | North Thames | 380 | 377 | 377 | 376 | 378 | 375 |
| | North West | 534 | 530 | 531 | 538 | 546 | 545 |
| | West Midlands | 420 | 416 | 414 | 417 | 420 | 418 |
| NGN | Yorkshire | 300 | 304 | 313 | 321 | 331 | 339 |
| | Northern | 226 | 231 | 236 | 242 | 250 | 255 |
| SGN | Scotland | 284 | 280 | 275 | 270 | 265 | 260 |
| | Southern | 320 | 314 | 307 | 300 | 293 | 286 |
| | South East | 472 | 430 | 421 | 411 | 402 | 393 |
| WWU | Wales North | 71 | 68 | 67 | 67 | 66 | 66 |
| | Wales South | 165 | 165 | 165 | 165 | 165 | 165 |
| | South West | 348 | 343 | 339 | 335 | 332 | 329 |
| **Total** | | **4224** | **4160** | **4146** | **4147** | **4158** | **4141** |

7.4. Respondents stated that a significant amount of shrinkage volume is not strongly correlated with gas demand and suggested that the use of a shrinkage factor is inappropriate, as the leakage allowance linked to demand does not reflect the physical quantity of gas leakage. Our analysis, set out in appendix 14, supports this view.

7.5. We propose modifying the basis for setting the allowed volumes such that the allowance for leakage is calculated as a fixed annual volume per LDZ. We propose retaining the link with demand for volumes of own use gas and theft.

7.6. We propose to set shrinkage baselines made up of a fixed element combined with a shrinkage factor related to demand as shown in table 7.2.

### Table 7.2 - Shrinkage Volumes - proposed fixed element and factors

| Shrinkage volume (GWh) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2008-09 | | 2009-10 | | 2010-11 | | 2011-12 | | 2012-13 | |
| Owner | LDZ | Fixed Element | Factor | Fixed Element | Factor | Fixed Element | Factor | Fixed Element | Factor | Fixed Element | Factor |
| NGG | East Midlands | 383 | 0.032% | 383 | 0.032% | 383 | 0.032% | 386 | 0.032% | 385 | 0.032% |
| | East Anglia | 277 | 0.032% | 276 | 0.032% | 277 | 0.032% | 278 | 0.032% | 277 | 0.032% |
| | North Thames | 356 | 0.032% | 355 | 0.032% | 354 | 0.032% | 355 | 0.032% | 352 | 0.032% |
| | North West | 502 | 0.032% | 502 | 0.032% | 508 | 0.032% | 515 | 0.032% | 513 | 0.032% |
| | West Midlands | 397 | 0.032% | 395 | 0.032% | 397 | 0.032% | 399 | 0.032% | 397 | 0.032% |
| NGN | Yorkshire | 289 | 0.031% | 297 | 0.031% | 305 | 0.031% | 315 | 0.031% | 322 | 0.031% |
| | Northern | 218 | 0.031% | 223 | 0.031% | 229 | 0.031% | 236 | 0.031% | 241 | 0.031% |
| SGN | Scotland | 245 | 0.055% | 240 | 0.055% | 234 | 0.055% | 229 | 0.055% | 224 | 0.055% |
| | Southern | 288 | 0.055% | 281 | 0.055% | 273 | 0.055% | 266 | 0.055% | 259 | 0.055% |
| | South East | 388 | 0.055% | 378 | 0.055% | 368 | 0.055% | 358 | 0.055% | 348 | 0.055% |
| WWU | Wales North | 63 | 0.055% | 62 | 0.055% | 62 | 0.055% | 61 | 0.055% | 61 | 0.055% |
| | Wales South | 147 | 0.055% | 147 | 0.055% | 147 | 0.055% | 147 | 0.055% | 147 | 0.055% |
| | South West | 322 | 0.055% | 317 | 0.055% | 313 | 0.055% | 310 | 0.055% | 307 | 0.055% |

7.7. The quantity of shrinkage gas purchased by the GDNs is determined by Section N of the Uniform Network Code. The total quantity currently varies with demand. It would be up to industry to consider if the present arrangements remain appropriate following the introduction of a fixed volume for the leakage element of the revenue allowance.

### Determination of gas reference price for the shrinkage incentive

7.8. For the one year extension to the last price control the reference price was calculated as a 3.5 per cent uplift over the daily Heren three month-ahead forward offer price. We consulted in initial proposals on an alternative approach for setting the gas reference price calculation, including reviewing the uplift factor. Respondents suggested revising the uplift factor and using other price indexes such as day-ahead or SAP.

7.9. Historical analysis indicates that the current gas reference price formula set in the one year control has resulted in prices more than 6 per cent higher than day-ahead[6] prices. Using day-ahead prices would also eliminate the inherent price asymmetry due to forecasting errors. Analysis shows that day-ahead prices have been less volatile than three month-ahead prices. Further analysis is set out in appendix 14.

7.10. We propose to set the gas reference price for calculating allowed revenue as the day-ahead price and eliminate the uplift factor. We expect this to result in lower allowed revenue and customer charges due to the elimination of the uplift factor.

[6] For brevity we refer to weekend and day ahead prices as "day ahead" prices throughout this document

7.11. Allowed revenue would be calculated by multiplying the shrinkage volume, comprising a fixed component and a component linked to demand, by the reference price.

## Environmental emissions incentive

### Background

7.12. In initial proposals we considered strengthening the financial incentives to reduce shrinkage to reflect the environmental costs of gas leakage.

7.13. We propose setting a new incentive to reduce environmentally damaging emissions by exposing the GDNs to the environmental cost of these emissions calculated from the government's Shadow Price of Carbon (SPC) for greenhouse gas emissions.

7.14. Appendix 13 contains an impact assessment for the proposed environmental incentive.

### Proposed incentive design

7.15. We propose setting an ex ante baseline for gas leakage for each LDZ for the five year GDPCR period.

7.16. If the GDNs are able to reduce leakage below the baseline they will earn additional revenue that is broadly equivalent to the value of the reduction in environmental emissions based on the SPC. Conversely, if the LDZ emissions are above the baseline, the revenue allowance for that LDZ will be reduced by the cost of the emissions above the baseline.

7.17. This would internalise the social cost of gas emissions providing an incentive for the GDNs to reduce environmentally harmful emissions and would provide additional revenue to allow specific investment in projects to reduce emissions where this is economically efficient.

7.18. We propose introducing cap and collar arrangements to prevent unintended gains and losses should the outcome be significantly different to our expectations.

7.19. The GDNs have very little influence on the composition of gas entering the LDZ networks. Basing the incentive on the actual quantity of individual gas components would therefore expose the GDNs to windfall gains and losses as the gas composition entering their networks varied. We propose to use a constant gas composition and setting the incentive volume baseline on natural gas leakage measured in GWh as a proxy for greenhouse gas leakage. This considerably simplifies reporting and monitoring, while providing virtually identical incentive properties.

7.20. The proposed incentive raises the issue of periodicity of expenditure. Assuming that baselines are reset at the next price control then capex spent at the start of this price control period to reduce emissions will provide the GDNs with higher allowed revenue than if spent at the end of the period. We considered introducing a rolling incentive allowing the companies to benefit from five years of environmental incentive revenue allowances irrespective of when the investment is made. We are not convinced that such an incentive is appropriate at this time given the lack of historical information relating to the impact of an environmental incentive and the complexity of introducing such a refinement at this early stage.

**Determination of environmental emissions baseline**

7.21. We have examined the trend in historical and forecast reduction of greenhouse gas emissions, considered the GDNs' submissions and our consultant's views and performed our own analysis.

7.22. We propose to set baselines for gas leakage that reflect our view of the quantity of gas leakage in the absence of this incentive. These are identical to the leakage component of the shrinkage incentive shown as the fixed element in table 7.2 above.

**Determination of the strength of the environmental emissions incentive**

7.23. Defra recently published interim guidance on valuing greenhouse gas emissions[7]. This guidance introduces a "Shadow Price of Carbon" (SPC), which is stated in equivalent tonnes of carbon dioxide (CO2) emissions as £25.40 in 2007 prices, increasing in real terms by 2 per cent per annum.

7.24. In 2005-06 prices, this equates to an average of £93 per tonne of carbon over the price control period, which is approximately £416/tonne of natural gas, 87 pence per therm or £29.7 per MWh. According to data published by the Joint Office, leakage from the distribution networks during the gas year 2006-07 totalled 3978 GWh. Applying the SPC to the total leakage results in a shadow cost for greenhouse gas emissions from the GDNs in 2006-07 of £118 million.

7.25. On 17 July 2007 Defra published the government's air quality strategy[8], which includes references to the social cost of certain pollutants, including ozone, which is formed from methane in the atmosphere. When compared to the social cost of greenhouse gas emissions the cost of air pollution from gas leakage is relatively small.

7 http://www.defra.gov.uk/environment/climatechange/research/carboncost/index.htm
8 http://www.defra.gov.uk/environment/airquality/strategy/index.htm

7.26. Air pollution is estimated to reduce the life expectancy of every person in the UK by an average of 7-8 months; with estimated annual health costs of up to £20 billion. Air pollution also damages our ecosystems.

7.27. We do not consider that it is appropriate to increase the strength of the incentive specifically to take account of air quality issues, partly because it would be difficult to establish an appropriate financial value. However, air quality considerations reinforce the benefit of introducing a leakage incentive and support an incentive strength towards the higher end of the range we would consider appropriate based solely on global warming considerations.

7.28. We propose setting the strength of the incentive at £28.50 /MWh (2005-06 prices) increasing by 2 per cent per annum in real terms for the duration of the price control period.

### Financial impact and caps and collars

7.29. We anticipate that the GDNs will be able to reduce emissions by 2 to 4 per cent over the period, resulting in an incentive value in the order of £2.4 to £4.8 million per annum.

7.30. If the companies are able to reduce leakage by substantially more than this it is likely to be due to factors that we are unaware of and there is a possibility therefore of an unintended outcome. If the companies are unable to reduce leakage they may be exposed to disproportionate financial penalties. For these reasons we propose to introduce cap and collar arrangements limiting the total aggregate value of the incentive across all LDZs to a total of between £7 and £10 million per annum. We propose to apportion this as a symmetrical cap and collar applying to each individual LDZ pro-rata to its leakage baseline. We consider that the range we are proposing encompasses our range of expected emissions reduction but will not be a significant consideration with respect to cost of capital.

### Reporting

7.31. Under the present arrangements shrinkage volumes are determined ex ante during the price control process and set for the duration of the control period. Actual shrinkage levels do not affect allowed revenue so there is no requirement for Ofgem to validate the reported amounts of shrinkage unless asked to veto shrinkage proposals made under the UNC process.

7.32. If the proposed environmental emissions incentive is implemented the actual emissions will affect allowed revenue and we will require the companies to report the emissions to us for the purposes of this incentive.

**Shrinkage Model**

7.33. In initial proposals we said we would work with industry over the course of the summer to review the current leakage model, the robustness of the data entered into the model and governance arrangements. We have held meetings with the GDNs and received supplementary information about the model.

7.34. The shrinkage model includes leakage factors for underground pipes and above ground equipment. It also includes factors for the calculation of gas usage by above ground equipment such as gas heaters. It is possible to remove items related to own use gas and theft of gas such that gas leakage is reported as a separate subset of shrinkage. Although the uncertainty of the model is around +/- 20per cent, we consider that the leakage subset provides an appropriate measure of leakage for this incentive.

7.35. It may be necessary to adjust the model during the price control period, for example to take into account new leakage reduction techniques which resulted in reduced emissions but did not result in a reduction in reported emissions due to limitations of the model.

7.36. We consider that adjustment during the price control period may change the basis for determining allowed revenue and is thus a matter for the Authority. Changes to the model may require us to reset baselines.

7.37. We recognise that if the model is changed it may be appropriate to reset baselines to avoid windfall gains or losses. We propose introducing governance arrangements that would prevent the model and baselines being changed unless this is proposed by the GDNs and approved by the Authority if it considers the change to be in the interest of consumers.

**Data validation**

7.38. We propose specifying the model used to calculate leakage either in the licence or in a document governed under it.

7.39. The GDNs will be required to report leakage using this model. We expect the internal controls implemented by the GDNs to ensure that data input to the model is robust and periodically audited. We may initiate periodic independent audits or reviews should we consider this appropriate.

7.40. We are considering performing a process audit during the first years of operation of the incentive to ensure that reporting is appropriate and robust.

## Network extensions update

7.41. As part of the initial proposals document, we published an impact assessment on facilitating network extensions in which we proposed to implement Option 6 complemented by Option 3a[9].

7.42. Responses to our initial proposals were generally positive, although some issues were raised over the detail. Appendix 5 sets out Ofgem's views on the specific comments made by respondents on network extensions.

7.43. After careful consideration of responses, our final proposal continues to be option 6 complemented by the discretionary reward scheme. We consider it appropriate for the allowance for network extensions to be capitalised and added to the GDNs' RAV, with the capital charges incurred over the price control being recovered on an NPV-neutral basis as part of the subsequent price control allowance.

7.44. We expect GDNs to come forward with proposals to amend their existing connection charging methodology statements under standard licence condition 4B to accommodate the arrangements under option 6. These proposals should cover how the economic test would be amended and which communities this amendment would apply to.

7.45. In initial proposals, we proposed using the Index of Multiple Deprivation (IMD) to target which non-gas communities will be eligible to receive special treatment under Option 3a and 6. We also proposed using a target raw score of the IMD. An alternative is to use a target percentage. We undertook some analysis to assess whether an IMD target raw score or an IMD target percentage would be most effective. This involved comparing the income distribution of England, Scotland, and Wales and checking the robustness of each of the countries' IMDs to previous versions. Although the results of this analysis were mixed, on balance, we consider a target percentage to be appropriate. Consequently we propose that network extension communities be targeted based on a specific percentage – say 20 per cent of the most deprived areas.

7.46. There are separate IMDs for each of England, Scotland and Wales. The IMDs for each country are calculated on a reasonably comparable basis so a uniform percentage target for all the IMDs is justified. This should give all GDNs an equal opportunity to carry out network extensions to fuel poor communities.

[9] Option 6 consists of amending the Economic Test when it is applied to non-gas fuel poor communities, and Option 3a involves introducing a Discretionary Reward Scheme (DRS) which would include a network extensions dimension. Please see GDPCR Initial Proposals Impact Assessment Appendices, ref. no. 125b/07, page 4.

## Innovation Funding Incentive for Sustainable Development

7.47. We intend to introduce an Innovation Funding Incentive for GDNs. This is modelled on the scheme already in place for electricity distribution and will provide special focus for Research, Development & Demonstration (R,D&D) activities. It is proposed that these activities should be targeted to deliver environmental and sustainability benefits, through alignment with Ofgem's five published sustainable development themes. The incentive will be named the innovation funding incentive for sustainable development (IFI/SD). We have designed the scheme to focus on the substantial sustainable development challenges facing the sector which include novel solutions to address shrinkage, and the strategic asset management of critical national infrastructure.

7.48. The positive outcomes now being reported from the IFI in electricity distribution, give grounds for confidence that an IFI scheme for gas distribution will bring benefits for customers in the medium and longer term. 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). The scheme will require that all projects in a GDN's R,D&D portfolio align with one or more of Ofgem's five Sustainable Development themes[10].

7.49. 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. 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.

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

7.51. The GDNs will be required to report on IFI/SD projects in accordance with regulatory instructions and guidance (RIGs) and a Good Practice Guide. It is proposed that the GPG should be developed by the GDNs, following the principles established in Energy Networks Association Engineering Recommendation G85 for

[10] 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

the existing IFI schemes, and approved by Ofgem. The ENA has indicated that it is willing to be custodian of this IFI/SD document.

7.52. An impact assessment and further details of the proposed IFI/SD framework are set out in appendix 12.

# 8. Other issues

**Chapter Summary**

This chapter includes other issues that make up the price control arrangements and include our current thinking on the funding of xoserve and update on independent systems.

**Question box**

There are no specific questions in this chapter.

## Funding of xoserve

8.1. Initial proposals set out that we considered a "core plus user pays" approach to the funding of xoserve would bring about benefits to consumers in the medium term. We considered the governance arrangements to be outside of the price control and expected that the industry would work together to develop and implement the necessary arrangements in time for implementation from the start of the price control. A number of the responses raised concern over the detail of the governance arrangements necessary to implement core plus user pays approach to the funding of xoserve. Following initial proposals, an industry group has been established through the joint office to develop the required governance arrangements and has established a work programme to take this forward.

8.2. There were mixed views on the necessary modifications to the GDNs' licence in particular SSC A15. As part of GDPCR we are developing the necessary licence drafting in parallel with the GDPCR consultation process. We have recently published an initial licence drafting consultation[11]. This includes proposed changes to SSC A15. It will be important for the price control and the licence drafting process to monitor the contractual, charging and governance arrangements being developed by the industry and take these into account where necessary particularly when developing changes to the GDNs' licence.

8.3. We note that there is little support for a mechanism to value redundancy from the UK link replacement as part of the funding arrangement. As noted in initial proposals although we consider that this may provide a windfall to the GDNs and xoserve, as they are unlikely to incur material costs in providing further user pays services, the replacement is at the end of the price control period and therefore the

[11] 221/07 - GDPCR: Initial licence drafting consutlation, www.ofgem.gov.uk

scope provided for creating additional value from this redundancy within this coming price control period is limited.

8.4. We also note that in general respondents considered the existing arrangements adequate for ensuring the continued performance on the full range of services provided by xoserve. This was not a view shared by all shippers with some raising concern that the safeguards were not adequate. At this time we do not intend to change our approach but will keep this issue under review to ensure that the new core plus user pays arrangements do not affect the continued performance of xoserve.

## Independent systems

8.5. 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 located within their distribution area[12]. The large majority of these networks are in Scotland[13].

8.6. Initial proposals noted that DBERR officials had indicated to Ofgem that, subject to the views and evidence of interested stakeholders, the Secretary of State for Business, Enterprise and Regulatory Reform was minded to require that there should continue to be arrangements to protect the interest of consumers connected to independent systems. He proposed to consult on this question, and the form that any future arrangements might take.

8.7. At the beginning of August DBERR published a consultation document.  The closing date for responses is 27 September. We expect to take account of any decision made by the Secretary of State in adjusting the price control arrangements and amending the relevant licence conditions. Further information in DBERR's consultation[14].

[12] 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
[13] In addition, small independent systems are located in Wales and North England.
[14] BERR consultation document: "Proposal to continue cross-subsidy arrangements for independent gas systems" www.berr.gov.uk/consultations/page40684.html

# 9. Financial issues

**Chapter Summary**

This chapter sets out Ofgem's updated position on cost of capital, including the conclusions of our risk analysis. A more detailed discussion of the cost of capital is set out in appendix 16 including reviews of several papers prepared by economic consultants on behalf of respondents. It also provides some clarity on specific aspects of the way we calculate the tax allowance, and outlines the consequences for the financeability of the GDNs of the proposed allowances, based on our financial model, which is based on the GDNs' individual revenue allowances applied to a notional financial structure.

**Question box**

**Question 1:** Does our risk analysis support a range for the cost of equity of 7.0-7.5per cent
**Question 2:** Is it appropriate to continue to maintain a consistent approach to cost of debt to that taken in TPCR?
**Question 3:** In the light of both the results of our risk analysis and the levels of actual gearing observed in the sector, is there a compelling reason to change our notional gearing assumption from 62.5per cent?
**Question 4:** Is our approach to determining the GDNS' tax allowances appropriate?
**Question 5:** Should we make a financeability adjustment in cases where a GDN fails to meet our target ratios because of its own actions, such as penalties incurred under incentive schemes?

## Cost of capital

### Comparative Risk Analysis

9.1. The fourth consultation document outlined our intention to perform a comparative risk analysis between regulated networks, specifically to compare the required return on capital for GDNs under their price control proposals with the required return on capital for transmission operators (TOs) under their price control settlement, and to review whether those risks are asymmetric. We noted that the level of data available would limit the detail of the approach to be taken, and that the analysis would need to avoid spurious accuracy.

9.2. In line with this intention, we have kept the comparative risk analysis at a fairly high level. We have measured the relative variability of operating expenditure (opex), replacement expenditure (repex) and capital expenditure (capex), taking into account the incentive strength faced under the respective price controls, and the relative scale of each category of expenditure between GDNs and TOs. We have focussed on operational risks. It is our view that the assumptions used in setting allowed returns as a proportion of RAV, based on equity and debt financing of that RAV, should ensure that a comparable level of financial risk arises for all network owners, when measured as a proportion of either return on equity or return on total capital.

9.3. Based on this analysis, we consider that it is feasible to make conclusions about the relative risk of the various categories of activity, and whether TOs and GDNs face comparable levels of risk (measured by variability of expenditure) when undertaking the same activity. We have then estimated confidence intervals around the inputs using standard statistical techniques. Table 9.1. summarises the data used in the analysis.

**Table 9.1: Analysis of operational risk of GDNs and TOs**

| Category | Average annual expenditure / RAV | | Incentive strength (average) | | Variability of expenditure | |
|---|---|---|---|---|---|---|
| | TOs | GDNs | TOs | GDNs | TOs | GDNs |
| Capex | 10% | 3% | 25% | 33% | Medium | High |
| Repex | - | 6% | - | 33% | - | Medium |
| Opex[15] | 3% | 6% | 100% | 100% | Low | Low |

9.4. The variability measures were converted to point estimates of standard deviation, with the conclusion that the combined exposure for GDNs is higher, and that this difference under commonly adopted assumptions, is statistically significant. Based on our point estimates, the differential equates to 0.3 per cent differential in standard deviation of returns on RAV per annum, with a 95 per cent confidence interval of 0.2 per cent to 0.4 per cent.

9.5. The main driver of this differential is the larger operating costs of running the distribution network, given the high incentive rate applied to opex. This is partly offset by the larger transmission capital investment programme, which is larger than the GDN capex and repex programmes combined. However, the GDNs also appear to face higher risks on their capex programme (this is likely to be due to portfolio effects – the TO capex programme is made up of several large projects, whilst each GDN typically only has one major project in any price control) and face slightly higher incentive rates on capex (including repex).

9.6. The above analysis is based on annual variability of expenditure. Variability across the five years of the price control in total is lower, due to a diversification effect. There is also less data available, resulting in wider confidence intervals. Using our revised point estimates, the differential was no longer statistically significant at the 95 per cent level.

[15] Opex risk excludes items for which the GDNs have been protected from risk due to the inherent uncertainty and their inability to control them, such as business rates, pension deficits and GDN shrinkage gas purchases

9.7. The conclusion represents a measure of relative standard deviation of returns only, and does not directly convert to a higher cost of capital. For example, Europe Economics (2006)[16], when analysing the relative risk of the different airports operated by BAA, concluded that any differences in the risk taken from an operating cost perspective were immaterial when converted to a beta differential, and should not impact the allowed return on capital.

9.8. Appendix 15 provides greater detail on our approach, including the parameters used. The treatment of different risks and the interaction with market measures of the cost of capital, including CAPM. In addition we consider in detail the approaches suggested by consultation responses.

**Asymmetric Risk**

9.9. Some risks faced by network operators are asymmetric. Asset stranding and operational failure are examples of downside risks with no offsetting upside potential. By contrast, Ofgem's duty to ensure that network operators can finance their activities limits network operators' downside exposure to major adverse events outside their control.

9.10. Our view is that the recent price controls do not provide sufficient evidence to demonstrate statistically whether there is a differential in asymmetric risks faced by GDNs or TOs. The GDNs and NGGT were set a single price control from 2002 to 2007, and Transco's acceptance of that control could only confirm that they felt the balance of risks across the different controls was acceptable.

9.11. In addition, any average underperformance by the GDNs effectively represents a single statistical data point, not enough to demonstrate a pattern. Nevertheless the data does provide support for two qualitative arguments as to why the GDNs face greater asymmetric risk:

- the GDN risks are dominated by a large number of operational risks which, even if costs were to increase sharply, would be less likely to threaten the ability of the GDNs to finance their activities than the larger transmission projects. While the Authority's duty to secure that network licensees are able to finance their business applies equally to all types of network, the risks that the TOs face are more likely to be of the sort that requires the Authority to take action under this duty to mitigate any losses incurred; and
- the large portfolio of transmission capex projects provides the potential for the TOs to offset one project which increases in scope with a reduction in scope elsewhere. The GDNs' LTS capex tends to be focussed around a small number of projects (frequently one), and therefore where a scope overrun arises, this results in a capital overspend. The evidence from the data is that scope overruns

[16] "Estimating Separate Costs of Capital for Heathrow and Gatwick", Europe Economics, 2006.

are common and that this therefore could be considered to pose an adverse asymmetric risk to the GDNs.

## Implications for the cost of capital for the GDNs

*Cost of Equity*

9.12. Our assessment of the available evidence suggests that the GDPCR price control proposals represent at least as much risk to GDNs' returns as the TPCR settlement does for TOs. Specifically, there is a statistically significant differential between the volatility of returns for GDNs and TOs, over the range of activities to be undertaken in the following price control.

9.13. However, the differential represents only a small portion of total risk taken, and is only statistically significant when using annual data, whereas price controls are set over five years. The analysis demonstrates that the GDNs are taking at least as much equity risk as the TOs, but it is not possible to convert that directly to an impact on the cost of equity.

9.14. In addition, there are a number of qualitative considerations which suggest that the skew (i.e. the impact of the asymmetric risks) of the expected return may be more favourable for TOs, than for GDNs. The price control allowances represent point estimates of the future costs of running the networks. To the extent that there is a skew in expected returns, then a small adjustment to the allowed return on capital to offset the skew would be consistent with a set of allowances such that investors could reasonably expect to earn a return equal to our assessment of their cost of capital.

9.15. We have reviewed whether market data exists to back up the analysis of the relative risk of transmission and distribution. In particular, we have reviewed a submission from the GDNs, produced by Oxera. This analysis argues that traded gas distribution companies exhibit higher risk than transmission companies, as measured by asset beta. We consider that the analysis has some limitations. Nevertheless, the analysis supports the view that gas distribution is at least as risky as transmission, within the context of the price control.

9.16. While the evidence suggests that the cost of equity for GDNs should not be lower than for transmission, we have not increased the cost of equity in updated proposals from 7.0 per cent, which was also the cost of equity used in TPCR. As noted above, we believe that 7.0 per cent cost of equity is compatible with the results of our analysis. Consideration should also be given to the question of whether 7.0 per cent would still be the correct value for the cost of equity for transmission if reconsidered today. The appropriate cost of equity is a matter to be decided at final proposals, following consideration of the final shape of the price control, and taking into account any further responses. On the basis of the analysis carried out to date any increase at final proposals is not likely to be more than the top end of the range of 7.5 per cent as outlined in initial proposals.

*Gearing*

9.17. In initial proposals, we used a gearing ratio of 62.5 per cent. This reflected both that the previous gas distribution control had used a gearing ratio of 62.5 per cent, and also that the GDNs had succeeded in increasing gearing levels to 70 per cent and above while maintaining a comfortable investment-grade credit rating.

9.18. We consider that these arguments continue to apply. The result is a use of a gearing ratio higher than Transmission (60 per cent). We stated in the fourth consultation document that the debt and equity risks did not have to be in the same direction. Evidence from the actual gearing structures suggests that higher gearing is more appropriate for the GDNs. This is consistent with the financial model for transmission, which indicated that the large capital investment in transmission companies can result in sharp increases in gearing, in some cases requiring an equity injection, and that lower initial gearing may be justified. We therefore propose to retain our modelling assumption of 62.5 per cent.

9.19. Our financial model does indicate that gearing levels above 70 per cent are not consistent with comfortably investment-grade interest cover ratios, and therefore may only be appropriate for GDNs who have been able to outperform Ofgem's interest assumptions. We have not therefore sought to increase gearing from the levels in initial proposals.

*Cost of Debt*

9.20. Our approach to the cost of debt is to place weight on a combination of trailing averages for the cost of debt, long-term averages and current rates.

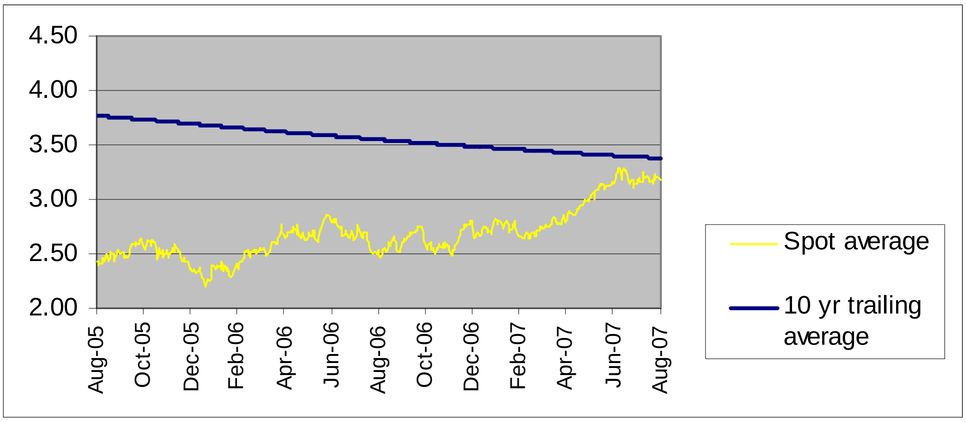
9.21. In initial proposals, we used 3.55 per cent for the cost of debt. This compares to 3.75% in TPCR, where we drew on a wide range of evidence, including spot rates, ten-year trailing averages and very long-term indicators to determine the cost of debt. The final decision placed more weight on very long-term averages and ten-year trailing averages, rather than short term measures. This is consistent with the nature of most utility financing. Since then the ten-year trailing average has continued to fall, and so we based our cost of debt at initial proposals on the number used in TPCR, less 20 basis points (bp) to reflect the falling ten-year trailing average.

9.22. The fall in the trailing average reflected that risk-free rates in the 1990s were generally around 1.5 – 2 percentage points higher than they are today. The average for debt premia has a much smaller impact – the long-term average single-A debt premium is around 1.1 per cent and does not change substantially over time.

9.23. Spot rates have been volatile since initial proposals. Debt premia have risen according to our usual measure – although utility spreads seem to have risen by less, which is consistent with utilities being viewed as a safe haven in difficult markets.

9.24. Nevertheless, the spot rates have remained below the level used in our modelling assumption for initial proposals. Figure 9.1 below indicates the pattern of rates using the Bank of England ten year zero coupon real gilt yield + the average of A/BBB corporate premia.

**Figure 9.1– Spot interest rates[17] compared to ten-year trailing average**




9.25. We have considered the use of debt indexation in this review. We consider that, while debt indexation may have benefits, it is complex and would require a separate full consultation. We have decided that this review is not the appropriate context in which to make a decision on debt indexation, and will take this forward separately.

9.26. We have also considered whether an appropriate reaction to the rising spot rates would be to include triggers for re-setting the cost of debt, as suggested by CEPA[18]. Specifically, if spot rates rose above allowed rates sufficiently to weaken financial ratios well below comfortably investment-grade levels, triggers would increase allowed revenues to offset these increased costs, at least with respect to incremental debt. Triggers offering protection against rising rates should be offset by triggers protecting consumers against falling rates.

9.27. We have concluded that it is not appropriate to include triggers at this review. We have performed sensitivity analysis to rises in spot interest rates, and we consider that there is sufficient headroom within the allowed cost of debt relative to recent rates to allow a notional GDN to absorb increases in rates over the forthcoming control period. The introduction of a trigger mechanism could also have

[17] Interest rates are based on 10 year Bank of England real rates + average of A/BBB spreads from Bloomberg
[18] "The allowed cost of capital - Ofgem: GDPCR 2008-2013", CEPA, 2007

an impact on the cost of equity and the gearing level, which in theory include an allowance to reflect financing cost risk.

9.28. The higher rates over the past few months have not had a significant impact on ten-year trailing averages. However, we will review the position at final proposals and consider the extent to which we should place more weight on movements in the trailing average as opposed to very long-term indicators.

9.29. The submissions from Oxera on behalf of the GDNs suggest that either a relative risk differential or a gearing level above 60 per cent imply a debt premium above Transmission. We do not agree, pointing to the analysis from Smithers (2006) that utility spreads are commoditised for utility debt with similar tenor and credit rating.

*Vanilla WACC*

9.30. Our modelling assumption for the vanilla WACC is given in Table 9.2 below. A final decision on the allowed return on capital will be made at Final Proposals.

**Table 9.2 – modelling assumption for GDPCR updated proposals**

| | TPCR 2007-12 | GDPCR initial and updated proposals |
|---|---|---|
| Cost of Debt | 3.75% | 3.55% |
| Cost of Equity | 7.0% | 7.0% |
| Gearing | 60% | 62.5% |
| Vanilla WACC | 5.05% | 4.84% |
| Post-tax WACC | 4.4% | 4.2% |

9.31. We note that our modelling assumption represents a lower cost of capital than for Transmission. As outlined above, we consider that this is a logical conclusion to the separate consideration of the financing and equity risks taken by the GDNs.

9.32. We received a number of detailed submissions which we have used to assist the preparation of our analysis above. We provide greater detail in Appendix 9.

## Modelling

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

### Tax

9.34. 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 they are still subject to consultation.

9.35. While the GDNs may in practice incur some expenditure that is not deductible, such as disallowable entertainment or expensive leased cars, these are not specific areas of expenditure for which we make opex allowances, and in any case 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.

9.36. 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.

9.37. 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.

### Dividends

9.38. 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 average for publicly listed UK utilities.

### Profiling

9.39. 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[19].

[19] GDPCR Initial Proposals Document, 29 May 2007, Ref: 125/07

## Assessing financeability

9.40. This section sets out our current 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

9.41. 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 (all as per DPCR4) and Post Maintenance Interest Cover Ratio ("PMICR").

9.42. 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.

9.43. In line with previous price controls, we are not presuming any index-linked debt in our financial model. 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.

9.44. The results of our financeability review will be materially affected by decisions on the timing of allowances for capex and repex. In our initial proposals we said that we would consider ahead of updated proposals whether the following three assumptions remained appropriate:

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

9.45. In all three cases we have opted to maintain the existing treatment, as explained in the paragraphs below.

9.46. For updated proposals, we have continued to finance repex 50per cent in the year incurred and 50per cent over 45 years. While repex is an enhancement to the long term asset base, the renewal programme is primarily concerned with present safety requirements rather than increasing the networks' capacity or functionality for the benefit of future customers. We consider that it remains appropriate for present consumers to fund a proportion of the repex programme, while the remainder is funded over the life of the assets.

9.47. We continue to treat non-operational capex in the same way as operational capex. Treating non-operational capex as opex would lead to increases in allowed revenues and in the volatility of those revenues over the period 2008-13, which we consider would outweigh any potential benefit to consumers arising from the stronger incentive properties of opex treatment. Our decision is taken in the context of this price control, and a different conclusion may be drawn in other price controls.

9.48. We continue to fund capex over a period of 45 years unchanged. We have seen no evidence to suggest that it would be appropriate to assume a longer or shorter period.

*Outcomes*

9.49. Our review of financeability indicates that for the majority of GDNs, the package of ratios arising from our notional assumptions is consistent with a comfortable investment grade credit rating.

9.50. As at initial proposals one GDN, Scotland, performs relatively poorly. Its PMICR position is particularly weak. Another GDN, Southern, has a similarly weak PMICR, although it performs better than Scotland on other ratios.

9.51. The main reason for these poor results appears to be the impact of a relatively high level of 'pot 2'[20] 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.

9.52. As the pot 2 penalty is the result of GDNs' overspend against allowed capital and replacement expenditure allowances, we do not view a financeability adjustment to be appropriate where this is the cause. After adjusting for the impact of this item, the financial ratios of both companies are sufficiently improved that we do not believe a financeability adjustment is required under these proposals.

[20] 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 the proposals

**Chapter Summary**

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

**Question box**

There are no specific questions in this chapter.

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 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 (50per cent);
- a cash allowance equal to the return on RAV plus the depreciation. We assume that companies incur expenditure and receive allowances throughout the year, and therefore calculate this cash allowance indirectly using a ‘change in RAV’ methodology. This is explained in appendix 17;
- corporation tax;
- 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
- allowance for pension deficit recoveries and under recoveries from the 2002-08 controls.

## Overall impact of proposals

10.2. The 'base case' scenario outlined below shows the impact of changes to our repex, capex and controllable opex assumptions since initial proposals. 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, and that were not included in our calculations at initial proposals. These include:

- changes in the assumed cost of purchasing shrinkage gas. Our approach to shrinkage is set out in chapter 7. At initial proposals we assumed that the amount allowed for the purchase 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 and of our assessment of the volumes of shrinkage gas that GDNs will need to purchase in each year of the price control.
- 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 £2,420 million for the period 2008-09 to 2012-13, representing an average annual increase over this five year period of £30 million or 1.3 per cent[21]. Table 10.1 breaks these figures down by year, while Appendix 17 gives more detail on allowed revenues for each GDN.

**Table 10.1 Changes in allowances[22] (average all GDNs, £m, 2005-06 prices)**

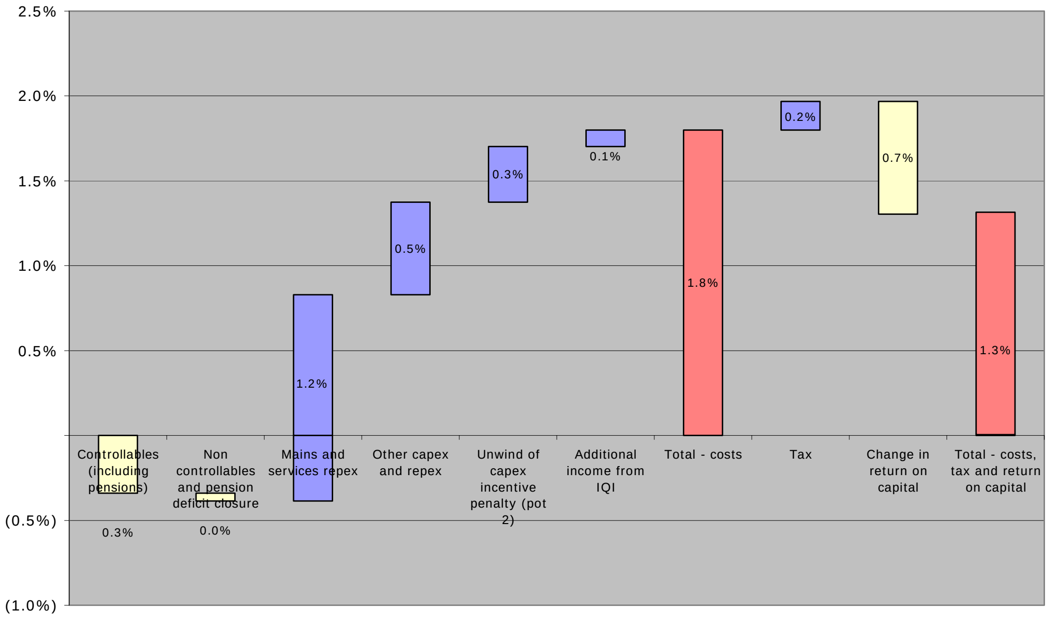
| | 2007-08 | 2008-09 | 2009-10 | 2010-11 | 2011-12 | 2012-13 | Total | Average |
|---|---|---|---|---|---|---|---|---|
| Allowed revenue | 2,327.7 | 2,371.5 | 2,422.1 | 2,410.3 | 2,438.3 | 2,458.0 | 12,100.3 | 2,420.1 |
| X | | -1.9% | -2.1% | 0.5% | -1.2% | -0.8% | -5.5% | -1.3% |

10.5. 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:

- increase in impact of mains and services repex (+1.2 per cent)
- increase in other capex and repex (+0.5 per cent)
- impact of 2002-07 'pot 2' expenditure entering the RAV (+0.3 per cent)
- reduction in controllable opex (-0.3 per cent)
- reduction in cost of capital (-0.7 per cent)

[21] The 1.3 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 18 provides more detail on the impact of our proposals on charges.
[22] Since we refer to the price control model as RPI-X incentive regulation, a positive value for X represents a fall in allowances and vice versa.

**Figure 10.1: Principal drivers of change in allowances**




10.6. 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 | Average X |
|---|---|---|---|---|
| NGG | East of England | 427.2 | 420.4 | -0.5% |
| | London | 245.1 | 275.9 | 4.1% |
| | North West | 285.5 | 292.0 | 0.8% |
| | West Midlands | 217.8 | 226.0 | 1.2% |
| NGN | Northern | 273.5 | 283.7 | 1.2% |
| SGN | Scotland | 194.3 | 199.6 | 0.9% |
| | Southern | 432.4 | 459.9 | 2.1% |
| WWU | Wales and West | 252.0 | 262.6 | 1.4% |
| | **Total** | **2,327.7** | **2,420.1** | **1.3%** |

*Impact of additional factors*

10.7. Table 10.3 below shows the impact of the additional factors listed above. Columns showing shrinkage, meter work 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 (£m, 2005-06 prices) including additional factors**

| | | Updated proposals - base case | | Shrinkage adjusted | Meter work adjusted | IFI adjusted | Updated 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 | 420.4 | -0.5% | -8.1 | 2.0 | 1.7 | 415.9 | -0.9% |
| | London | 275.9 | 4.1% | -5.1 | 0.8 | 1.1 | 272.8 | 3.7% |
| | North West | 292.0 | 0.8% | -6.6 | 1.4 | 1.2 | 288.0 | 0.3% |
| | West Midlands | 226.0 | 1.2% | -5.1 | 1.1 | 0.9 | 222.9 | 0.8% |
| NGN | Northern | 283.7 | 1.2% | -5.9 | 2.5 | 1.1 | 281.4 | 1.0% |
| SGN | Scotland | 199.6 | 0.9% | -4.0 | 2.3 | 0.8 | 198.7 | 0.8% |
| | Southern | 459.9 | 2.1% | -10.7 | 5.1 | 1.8 | 456.1 | 1.8% |
| WWU | Wales and West | 262.6 | 1.4% | -7.0 | 3.1 | 1.1 | 259.7 | 1.0% |
| | **Total** | **2,420.1** | **1.3%** | **-52.5** | **18.3** | **9.7** | **2,395.6** | **1.0%** |

## Implications for gas distribution charges

10.8. The price control allowances represent the maximum revenue that the GDNs can collect via gas transportation charges between 2008-09 and 2012-13. They are not the same as the impact of our proposals on the charges levied by GDNs to shippers. Appendix 18 sets out the reasons for this difference and presents an indicative impact on charges.

# 11. Next steps

**Question box**

There are no specific questions in this chapter.

## Consultation on the capacity outputs incentive

11.1. As discussed in chapter 6 we intend to consult on the parameters for the capacity outputs incentive through a separate consultation, so that the parameters can be informed by the OCS booking process. We intend to publish this consultation in mid October with a shortened consultation period of three weeks in order to include our final proposals on the incentive in the December final proposals document.

## Consultation on licence drafting

11.2. On the 10 September 2007 we published our initial views[23] on changes to the gas transporters' licence and the Gas (Standards of Performance) Regulations that are necessary to make our proposals for the Gas Distribution Price Control Review (GDCPR) effective. The proposed modifications are consistent with our initial proposals for GDPCR and further consultations will be necessary to review the licence conditions in light of final proposals for GDPCR and responses to the document. An update to the draft licence conditions is expected to be published on the 7 December following final proposals before formal consultation in February 2008.

11.3. In the main, the proposed modifications to the gas transporters' licence and the Gas (Standards of Performance) Regulations apply to the GDNs and have been developed through the GDPCR process but some of the changes proposed also impact on other gas transporters more generally, in particular IGTs. Parties should review this document for the detail of the proposed changes.

## Consultation on cost reporting

11.4. We have consulted during the summer on the collection of relevant cost information from the GDNs on an annual basis during the next price control period. We expect the annual process to be similar to that already undertaken for electricity distribution and gas and electricity transmission.

[23] 221/07 - GDPCR: Initial licence drafting consultation

11.5. This consultation raised a number of policy questions and we intend to bring together our conclusions in final proposals before finalising the Regulatory Reporting Pack (RRP) and Regulatory Instructions and Guidance (RIGs) early in 2008.

## Timetable going forward

**Figure 11.1- Ofgem's timetable for completing the gas distribution price control review**

| **Price control** | |
|---|---|
| Publish capacity outputs incentive consultation | October 2007 |
| Responses to the capacity outputs incentive consultation | November 2007 |
| Publish final proposals & publish proposed licence conditions | December 2007 |
| Publish section 23 notice | March 2008 |
| Modify licences | April 2008 |

# Appendices

### Index



### Index - Supplementary Appendices

# Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. In particular, we would like to hear from gas consumers and their representatives, gas distribution networks and any other interested parties.

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

1.3. Responses should be received by 22 October 2007 and should be sent to:

- GDPCR Responses
- Ofgem
- 9 Millbank
- London SW1P 3GE
- Email: GDPCR@ofgem.gov.uk

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

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

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

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

1.7. The remainder of this appendix restates the consultation questions for convenience.

**CHAPTER: One**

There are no specific questions in this chapter.

**CHAPTER: Two**

There are no specific questions in this chapter.

**CHAPTER: Three**

**Question 1**: Do you agree with our revised approach to setting opex allowances and the proposed allowances we have derived using that approach?
**Question 2**: Do you agree with our approach to the additional operating cost items included in these proposals covering the areas where our work was incomplete at initial proposals?

**CHAPTER: Four**

**Question 1:** Do you agree with our revised approach to setting capex and repex allowances and the proposed allowances we have derived using that approach?

**CHAPTER: Five**

**Question 1**: Do you agreed with our updated proposals for the quality of service arrangements?

**CHAPTER: Six**

**Question 1**: Do you agree with our view that an opex rolling incentive is not appropriate?
**Question 2**: Is our approach to capping the expenditure under the mains and services incentive appropriate?
**Question 3**: Is our approach to allocating domestic purge and relight costs to services costs appropriate?
**Question 4**: Do you agree with our approach to the capacity outputs incentive? What are the issues raised by incentivising or not NTS flex capacity?
**Question 5**: Should the volume targets for the flat capacity incentive vary with changes in the calorific value (CV) of gas?
**Question 6**: Is it appropriate to allow a price control re-opener (subject to certain criteria) for any capex spend that may be required following the interruption auctions?
**Question 7**: Is it appropriate to have an adjustment mechanism for the treatment of emergency services costs arising from the loss of metering? If so do you agree with our approach and methodology for the parameters?

**CHAPTER: Seven**

**Question 1**: Is it appropriate to roll forward the existing shrinkage incentive and if so do you consider the leakage volumes appropriate?
**Question 2**: Is the gas reference price formula appropriate?
**Question 3**: Should Ofgem establish a new incentive to target harmful environmental emissions?
**Question 4**: Do you support the design of the environmental incentive and its parameters?
**Question 5**: Are the strength and baselines for the incentive appropriate?
**Question 6**: Are the cap and collar arrangements appropriate?
**Question 7:** Is it appropriate to introduce a mechanism to address periodicity of investment?
**Question 8**: Are the leakage model and governance arrangements appropriate?

**CHAPTER: Eight**

There are no specific questions in this chapter.

**CHAPTER: Nine**

**Question 1:** Does our risk analysis support a range for the cost of equity of 7.0-7.5per cent
**Question 2:** Is it appropriate to continue to maintain a consistent approach to cost of debt to that taken in TPCR?
**Question 3:** In the light of both the results of our risk analysis and the levels of actual gearing observed in the sector, is there a compelling reason to change our notional gearing assumption from 62.5per cent?
**Question 4:** Is our approach to determining the GDNS' tax allowances appropriate?
**Question 5:** Should we make a financeability adjustment in cases where a GDN fails to meet our target ratios because of its own actions, such as penalties incurred under incentive schemes?

**CHAPTER: Ten**

There are no specific questions in this chapter.

**CHAPTER: Eleven**

There are no specific questions in this chapter.

# Appendix 2 – The Authority's Powers and Duties

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

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. The Authority also has other statutory duties in respect of the environment, as set out in various other Acts[24]. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[25]

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[26].

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[27]; and

[24] For example, the Environment Act 1995 and the Countryside and Rights of Way Act 2000
[25] Entitled "Gas Supply" and "Electricity Supply" respectively.
[26] 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.
[27] 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.

- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[28]

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

- Promote efficiency and economy on the part of those licensed[29] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

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

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

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[30] 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.

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

# Appendix 3 - 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.

**D**

Direct activities (operating expenditure)

Direct activities are the core activities carried out by GDNs eg repair and maintenance of pipelines, 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 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 eg human resources.

**L**

### Local Distribution Zones (LDZs)

LDZs are low pressure pipeline 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 pipeline 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 pipeline 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[31].

[31] http://www.ofwat.gov.uk/aptrix/ofwat/publish.nsf/Content/rd032001

### 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[32].

### 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.

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[32] 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 4 - Feedback Questionnaire

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

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

1.2. Please send your comments to:

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