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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 contains the main supplementary appendices for the Gas Distribution Price Control Review's (GDPCR's) updated proposals document. The supplementary appendices provide more detailed information regarding the issues raised in the main document. It also contains a summary of responses to the initial proposals document, together with Ofgem's views.

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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); and
- GDPCR Initial Consultation, December 2005 (Ref. 259/05).

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Appendix 5 – Responses to the initial proposals document

1.1. This appendix summarises the responses received from GDNs and other interested parties to questions posed in the initial proposals document, published in May 2007, together with our views.

1.2. We received 23 responses from the following organisations:

- Advantica;
- Age Concern;
- Centrica;
- CO-Gas Safety;
- EDF Energy;
- Energywatch;
- E.ON;
- Fuel Poverty Action Group (FPAG);
- Gas Forum;
- GMB;
- Health & Safety Executive (HSE);
- National Energy Action (NEA);
- National Grid Gas (NGG);
- National Grid NTS (NG NTS);
- Northern Gas Networks (NGN);
- RWE Npower;
- SBGI;
- Scotia Gas Networks (SGN);
- ScottishPower Energy Networks (SPEN);
- United Utilities (UU);
- Welsh Assembly;
- Wales and West Utilities (WWU);and
- xoserve.

1.3. Responses are available on Ofgem's website (www.ofgem.gov.uk).

1.4. Please note that when summarising respondents' views, we have referred to each GDN company as a (single GDN), even if the company owns more than one GDN.

Responses to Chapter 2 - Form, structure and scope of price control

1.5. The third consultation document set out a number of issues relating to form, structure and scope of the price control. Chapter 2 of the initial proposals document outlined our proposals in a number of areas and provided further details on our thinking. Respondents were asked the following question:

- Do you think that a wider deadband on the revenue recovery correction mechanism is appropriate in gas distribution?

Views of GDNs

1.6. All of the GDNs consider that a wider deadband on the revenue recovery correction mechanism is appropriate in gas distribution.

Views of other respondents

1.7. Among the non-GDNs who responded, one considers it should not be wider while one does.

Ofgem's views

1.8. We consider there is a case for the deadband to be greater in gas distribution than electricity due to the greater volatility in demand. There is evidence to support weather effects having a much larger effect in gas than electricity. This leads to volatility in income and allowed revenue.

1.9. As noted in initial proposals, some of this underlying volatility is diminished by the proposed removal of the volume revenue driver. We also note the GDN proposed charging modification that changes the capacity / commodity split, which would impact on the volatility of GDN income. Further information on our proposed approach is detailed in the main document.

Responses to Chapter 3 - Operating expenditure analysis

1.10. Chapter 3 set out our views on a range of policy issues associated with our analysis of the GDNs' forecast operating expenditure along with our initial proposals for operating expenditure allowances. Respondents were asked the following questions:

- Do you agree with our approach for setting opex allowances and the proposed allowances we have derived using that approach?
- Do you agree with the proposals to uplift allowances derived from disaggregated benchmarking so that they are consistent with the power of a top down approach?
- Do you agree that GDNs Emergency Service personnel should be required to carry and use carbon monoxide (CO) measuring equipment during gas emergency investigations?

Views of GDNs

1.11. One GDN thinks that Ofgem’s approach for setting allowances has the potential to deliver sensible allowances however it said there are flaws in each stage resulting in low allowances. It considers the methodology inappropriate, assumptions unsubstantiated and normalisation inadequate.

1.12. Another GDN has some concerns with the benchmarking. It says that Ofgem's hybrid approach leads to all companies, including the most efficient, having to catch-up to the benchmark target as well as to achieve frontier shift productivity improvements. The GDNs also questioned the appropriateness of the cost drivers used for the regression analysis, although they disagreed on what were the most appropriate drivers to use.

1.13. Another GDN considers the allowances insufficient due to unrealistic and flawed productivity assumptions and believes there has been insufficient dialogue to date.

1.14. The final GDN supports the use of appropriate and realistic benchmarks to determine comparative performance but considers that Ofgem's benchmarking methodology together with efficiency targets creates inequitable outcomes. All GDNs consider the real price effect (RPE) assumptions unrealistic.

1.15. GDNs also argued that the roll forward of workloads in our analysis understated the levels of workload that would be faced and overestimated the reductions in future workload that we assumed would arise due to the mains replacement programme (e.g. reductions in external publicly reported gas escapes (PREs)).

1.16. One of the GDNs considers the 5.6 per cent uplift to allowances derived from disaggregated benchmarking and based on top-down regression wholly inappropriate and unsupportable. Three GDNs consider that allowances derived from disaggregated benchmarking should be uplifted to the upper quartile in the top-down analysis, not the frontier.

1.17. GDNs argued that the case had not been made for our ongoing productivity assumption of 2.5 per cent per annum. The GDNs commissioned a report by First Economics which suggested little if any scope for ongoing productivity savings.

1.18. One of the GDNs supports a detailed review of Emergency Service Personnel (ESP) carrying and using CO measuring equipment during gas emergency investigations to establish exact requirements. Another GDN considers that additional costs must be allowed within the price control if this proposal goes ahead. Another GDN welcomes an industry debate on this issue but believes more work is needed to develop a working solution. The final GDN requires more information on the scope of work that will be carried out before providing any comments.

Views of other respondents

1.19. Overall, two non-GDNs agree with Ofgem’s overall approach for setting opex allowances. Energywatch welcomes the increased use of comparative benchmarking within and across the sector to determine what constitutes efficient expenditure.

1.20. One of the non-GDNs agrees in principle with the use of top-down as a sense check but says it is necessary to understand why top-down gives different results to bottom-up. Two non-GDNs consider that allowances should be uprated to upper quartile level of the top down analysis. Another non-GDN considers that the reasons for adopting different benchmark measures in top-down (frontier) and bottom-up (upper quartile) approaches are not clear, and that applying an uplift based on the top-down frontier is inconsistent with DPCR4's approach.

1.21. One non-GDN supports the use of a range of methodologies, and another considers that insufficient allowances have been made.

1.22. One non-GDN says there have been significant reductions in opex despite recognition of costs increases in certain categories. Finally, a non-GDN does not support the approach or the proposed allowances relating to xoserve activities as the proposed xoserve savings are based on inappropriate comparisons with GDNs that do not take account of the different nature of the xoserve and GDN businesses.

1.23. Non-GDNs argued that the case had not been made for our ongoing productivity assumption of 2.5 per cent per annum. Non-GDNs stated that the 2.5 per cent per annum assumption was conservative.

1.24. A non-GDN does not support ESPs carrying and using CO measuring equipment at this stage as many issues need to be addressed before proposals are moved forward. Three other respondents consider that ESPs should carry and use CO equipment and GDNs should receive appropriate allowances. One of these non-GDNs also considers that ESPs should carry out physical and neurological damage tests. Two other respondents consider that the benefits arising from such equipment should be quantified. If the HSE is persuaded that there would be material safety benefits, efficient costs of provision should be included within GDNs' forecasts.

1.25. The HSE notes that ESPs have a duty to meet the requirements of both health and safety legislation and Ofgem licence conditions when attending emergency situations resulting from the escape of gas, which includes suspected or actual escapes of CO. The HSE considers that within the current time and cost constraints, it appears impractical for ESPs to test all gas appliances using CO detection equipment on every emergency response. The HSE believes it is more practicable to place the onus on skilled and competent operatives to judge whether there is any benefit in using detection equipment to identify if CO is present in the atmosphere. However, the HSE notes the use of CO detection equipment by ESPs in the course of their investigations should not be precluded, but must be based on evidence that is in the interests of safety overall and the costs are not grossly disproportionate to the risks being mitigated.

Ofgem's views

1.26. We have made a number of changes to both our overall opex methodology and our detailed bottom-up analysis to take into account the concerns raised by the GDNs and other parties. These are discussed in detail in chapter 3.

1.27. In particular, we have now modified our approach to the uplift from bottom-up benchmarking to top-down so that it is based on an upper quartile top-down benchmark. This approach is more consistent with our approach in DPCR4 where overall opex allowances were based on an upper quartile top-down allowances.

1.28. We have also commissioned additional analysis by Reckon LLP to address comments raised by the GDNs on our productivity assumptions for opex. Based on this additional analysis we still consider a 2.5 per cent per annum assumption for ongoing productivity appropriate.

1.29. Based on our updated analysis of real growth in input prices we still consider our assumptions of 1 per cent per annum growth for contract labour, 2 per cent per annum growth for direct labour and 1 per cent per annum growth for materials to be appropriate. Further details are set out in chapter 3 and appendix 6.

1.30. We do not consider that it is appropriate to apply glidepaths in calculating opex forecasts. A glidepath would give more money to a less efficient GDN than it would to a GDN that is already at or near the benchmark. It potentially provides perverse incentives to have higher costs.

1.31. Our proposed approach for carbon monoxide is set out in of chapter 3.

Responses to Chapter 4 - Capital and replacement expenditure analysis

1.32. This chapter set out our analysis on the GDNs' capital and replacement expenditure as well as our initial proposals for capital expenditure and replacement expenditure allowances. Respondents were asked the following questions:

- Do you agree with our approach for setting capex allowances and the proposed allowances we have derived using that approach?
- Do you agree with our approach for setting repex allowances and the proposed allowances we have derived using that approach?

Views of GDNs

Capex

General

1.33. One GDN provided additional consultancy reports commenting on all areas of capex in response to PB Power's analysis. The reports also included further work on regional factors and impact of inflation.

LTS & Storage

1.34. The use of generic unit costs for LTS pipeline projects was challenged by the GDNs. The GDNs all proposed a number of reasons as to why there were project specific factors driving higher unit costs for their projects. The GDNs expressed concern that the same unit cost had been used for a transmission pipeline and storage pipeline despite the different characteristics of these pipelines.

Connections and mains reinforcement

1.35. In response to initial proposals three of the GDN owners raised concerns regarding the productivity assumptions applied to connections and mains reinforcement.

1.36. A number of GDNs raised concern over the use of 2005-06 actuals for the connections regression analysis and issue over data consistency.

1.37. The GDNs raised a concern that mains reinforcement data for a single year can be distorted and may not be typical or sustainable in future years, and to rely on this as the basis for generating allowances for the next five years could result in inappropriate allowances.

1.38. Two GDN owners challenged the assumption on the percentage of net capex to gross connections capex that had been used in initial proposals.

Non-operational capex

1.39. For GTMS and SOMSA costs, one GDN commented that as separation was driven by a regulatory requirement it is unfair to disallow any efficient costs.

Repex

Nominal unit costs

1.40. Two GDNs raised concern over the nominal unit costs used within the regression analysis.

Downsizing

1.41. One GDN commented on the downsizing of repex mains proposed for small diameter mains replacement in initial proposals.

Abandonment Ratios

1.42. One GDN expressed concern over the repex analysis being carried out based on mains laid rather than mains abandoned.

1.43. Two GDNs raised concerns regarding the proposed scaling back of the length of mains installed on the basis of a 1.05 to 1 abandon to lay ratio. With the proposed insertion programme it is argued that the ratio will be nearer 1 to 1.

Condition Workload Adjustment

1.44. One GDN owner argued against the proposed adjustments to their condition based workload in initial proposals.

Ongoing productivity

1.45. A number of GDNs have suggested that an assumption of 2 per cent per annum ongoing efficiency improvements for repex is inappropriate.

Regional Factors

1.46. One GDN highlighted regional factors as being an issue for contractors carrying out replacement work as well as operating costs.

Views of other respondents

1.47. A non-GDN considers that PB Power has done insufficient analysis on peak demand forecasts resulting in low confidence that the capex figures have any validity. It also says that PB Power has not addressed key drivers in sufficient detail for judgement to be made on capex forecasts. Another non-GDN respondent considers the approach taken to set capex allowances flawed. A further non-GDN thinks Ofgem should make it clear whether the proposed capex is higher than at the last price control period and, if it is, why.

Ofgem's views

Capex

General

1.48. The additional consultancy reports submitted in response to initial proposals have been reviewed as part of the update process together with the work to update the analysis for 2006-07 actuals. Chapter 3 of the main document presents Ofgem's views on real price effects and regional factors, and chapter 4 sets out our updated capex analysis.

1.49. As part of the work for updated proposals PB Power were commissioned to update their analysis for 2006-07 actuals and carry out a detailed review of LTS capex. This work included a review of GDN capex submissions, demand data and a consideration of the implications of UNC modification 90 on the GDNs forecasts. This work has been reviewed and our capex forecasts revised accordingly in chapter 4.

LTS & Storage

1.50. As part of the work for updated proposals we commissioned PB Power to carry out more detailed project specific reviews of LTS investment. As part of the LTS review our consultants considered the need and timing of projects taking into account UNC modification 90 and interruption reform and they have carried out a detailed desktop review of costs for the projects. This work includes further consideration of the demand forecasts used in LTS planning.

Connections and mains reinforcement

1.51. We have based our updated connections capex analysis on 2006-07 actuals. We consider that this has addressed the concerns over consistency in reporting.

1.52. We have reviewed the productivity assumptions for connections and mains reinforcement further in light of 2006-07 actual costs and have reduced the assumptions to one and a half per cent in each case.

1.53. We have reviewed the mains reinforcement costs and workloads and updated the regression for 2006-07 actuals. We consider that this forms an appropriate base for setting out expenditure forecasts.

1.54. Specific reinforcement has now been moved from the connections analysis to mains reinforcement. We have updated our calculations of net capex based on the GDNs' proportions of net to gross capex in their latest BPQ submissions with an adjustment for NGG to allow for Final Connections Allowances.

Non Operational Capex

1.55. Ofgem stated at the time of GDN sales that additional capex costs associated with establishing separate GDNs would not be passed onto consumers. We consider it is appropriate for our forecasts for GTMS replacement costs to be set on the basis that only one new set of systems is required rather than one per GDN owner. We also consider that SOMSA exit costs should be disallowed in accordance with these principles.

Repex

General

1.56. One of the largest impacts on the repex forecasts in this price control period is the requirement by the GDNs to meet the HSE target of removing all iron mains within 30m of a property over a 30 year programme. This programme commenced in 2002 with an agreement between the GDNs and the HSE to ramp up the workload in the early years of the programme.

Nominal Unit costs

1.57. We have updated the unit costs which are used to weight workload at different diameters in the repex regression analysis to take into account the 2006-07 actual costs. These have also been sense checked against contract prices.

Downsizing

1.58. Based on comments from the GDNs and further analysis we have halved the downsizing adjustments that we applied for repex in initial proposals.

1.59. The principal cost driver for mains repex is installed pipe and the regression analysis is carried out on this basis as the analysis can be further supported with actual lay lengths and contract prices. We have sense checked the repex analysis by re-running the regression based on abandonment lengths and this highlighted that basing the analysis on mains installed was not having an adverse impact on the GDNs' repex allowances.

Abandonment Ratios

1.60. We have reviewed the latest data and abandonment ratios of up to 1.1 to 1 (abandoned to lay) have been reported by the GDNs. Given the scale of the repex programme we consider there are further opportunities to rationalise the network and continue to propose a minimum abandonment to lay ratio of 1.05 to 1.

1.61. The issue of adjustments to the condition based workload is discussed in chapter 4.

Ongoing productivity

1.62. We still consider that an assumption of 2 per cent per annum for ongoing efficiency improvements for repex is appropriate based on the upper end of the range of assumptions put forward by the GDNs.

Regional Factors

1.63. The regional factors have been reviewed within chapter 3 of the main document. We do not consider different regional factors should apply to contractors employed directly on replacement activities compared to any other type of work.

Responses to Chapter 5 - Outputs

1.64. This chapter set out our proposals for improving quality of service outputs for consumers and the changes that we intend to make, as well as setting out our view on issues relating to the scope of gas networks. Respondents were asked the following questions:

- Do you support our proposals for changes to the outputs and quality of service arrangements?
- Do you support our proposals for improving the accuracy of pipeline records?
- Is Ofgem's proposed approach to setting allowances for the outputs and quality of service arrangements for 2008-13 appropriate?

Views of GDNs

1.65. In general, all of the GDNs support the rationalisation and simplification of standards of performance. However, one GDN considers that the current proposals do not achieve much simplification, and believes several opportunities to rationalise have been missed. Another GDN says that tightening existing standards and introducing new ones impose additional costs which need to be accounted for in allowances.

1.66. On proposals for improving the accuracy of pipeline records, one GDN considers that GDNs should only be assessed on measures over which they have direct control. This GDN considers it inappropriate for GDNs to be measured on timeliness with which they digitise records, and to use the absolute number of submissions under Digital Record Policy 4 (DR4) and Digital Record Policy 8 (DR8) as a performance metric. Another GDN supports the principles but 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 the HSE.

1.67. None of the GDNs consider Ofgem's proposed approach to setting allowances for the outputs and quality of service arrangements appropriate.

Views of other respondents

1.68. One of the non-GDN respondents says that overall GSOPs is the right approach but is concerned that GDNs will focus on the easiest parts of the network to give them the best chance of achieving the required standards. Another non-GDN says that proposals for changes to output and quality of service arrangements should be beneficial to customers and provide appropriate levels of protection. Energywatch fully supports the proposals simplifying service obligations on GDNs and has identified scope for further obligations to be developed in light of consumer experience. Three other respondents broadly support the proposals.

1.69. Five non-GDN respondents expressed support for the proposals for improving the accuracy of pipeline records.

1.70. Four non-GDN respondents consider Ofgem's proposed approach to setting allowances for the outputs and quality of service arrangements appropriate.

Ofgem's views

1.71. We consider that our proposed changes to the standards of performance simplify the existing arrangements by removing the overall standards and moving key obligations such as the emergency service standard and complaints standard either into the licence or guaranteed standards. They also provide improved protection to consumers through the introduction of new or strengthened guaranteed standards in areas that are important to consumers.

1.72. We consider that there are benefits in collecting information on the total number of DR4s and DR8s submitted the percentage of pipeline records digitised within 30 days and the number of undigitised main records. Focusing GDN management attention on these processes will highlight how pipeline records are managed and the timeliness with which they are updated and should encourage improvements in data over time. We recognise that a high number of DR4s may show that errors are being identified and therefore that the data is being improved.

1.73. We have updated our quality of service allowances in light of responses to initial proposals and additional BPQ information. This is discussed further in chapter 5.

Responses to Chapter 6 - Incentives

1.74. Chapter 6 set out our initial proposals for capex rolling incentives and the IQI and mains and services replacement incentive. This chapter also considers the issues associated with opex rolling incentives and the capacity output incentives. Respondents were asked the following questions:

- Are the proposals for the capex rolling incentive and IQI appropriate?
- Are the proposals for the mains and services replacement incentive appropriate?
- Is it appropriate to implement an opex rolling incentive?

Views of GDNs

1.75. In general, the GDNs consider the proposals for the capex rolling incentive and IQI appropriate but see no justification for not including the five per cent uplift which was allowed in DPCR4. Two GDNs expressed some concern over the implementation and operation of the IQI.

1.76. There was broad support for our proposals on the mains and services replacement incentive. One of the GDNs considers that the proposals for the mains and services replacement incentive will improve its effectiveness. Another GDN prefers option 1b (i.e. retain mains replacement incentive with separate unit costs for service replacement) if the incentive mechanism is adjusted to include services. This GDN considers that it would be better for all GDNs to face the same incentive rate.

1.77. One GDN considers that the justification for an opex rolling incentive on the basis of reducing periodicity has lapsed due to the introduction of benchmarking but there could be justification for an asymmetric roller. Another GDN says that an opex rolling incentive is needed to equalise the benefits of opex efficiencies across the five year price control. A further GDN agrees that an opex roller should be considered further however not at the expense of other incentives such as IFI. Another GDN supports implementation in principle but until allowances are known and confidence in comparability of data is increased, it cannot evaluate if there is any benefit. This GDN further says that an alternative is to introduce an asymmetric incentive.

Views of other respondents

1.78. Overall, two non-GDNs support the principle of a capex rolling incentive and IQI. One other respondent thinks the proposed IQI needs further calibration as it is overly harsh.

1.79. Two non-GDN respondents support an opex roller in principle. However, one of them believes it is more important to ensure incentives on capex and opex are balanced to avoid perversities. Another non-GDN thinks an opex roller should only be introduced where it can be demonstrated that reporting of costs is robust. A non-GDN thinks some form of opex retention mechanism is required, either separately or included in the opex rolling incentive to stimulate longer term innovation investment. Finally, a non-GDN considers that the proposed scheme would fail to encourage GDNs to address significant long term challenges facing the industry. It considers it appropriate to establish incentives to encourage robust long term R&D programmes.

Ofgem's views

1.80. We note the comments regarding the parameters of the IQI. The use of a five per cent uplift as per DPCR4 was not a specific regulatory precedent that must be perpetuated, rather a variable that is used in the context of the particular price control. Since the uplift represents a softening of the assumptions made in the base case, whether to include it or not depends on how challenging we believe the base case assumptions are in combination. Evaluating our revised base case assumptions, we have determined that it is appropriate to maintain our position of no uplift.

1.81. We are not proposing any further changes to the mains and services mechanism (except consideration of the application of a cap, please see chapter 6). We continue to believe this is the best way to incentivise an efficient approach to the HSE's required replacement programme and associated works. Since the principle of varying incentive rates for GDNs on capex and other repex does not appear to be controversial we do not see any serious cause for concern with applying those incentive rates to the mechanism.

1.82. The wide range of opinions regarding the introduction of an opex roller suggests that this is a finely balanced issue. Our proposed policy and the rationale underlying it are set out in chapter 6 and the final impact assessment in appendix 10.

Responses to Chapter 7 - Sustainable development

1.83. This chapter set out our initial proposals in a number of areas related to sustainable development. This included gas shrinkage arrangements, our proposals on extensions to the gas network and the introduction of a discretionary reward scheme. Respondents were asked the following questions:

- Do you agree with our assessment of the risks, costs and benefits attributable to the options for facilitating network extensions (Appendix 14)?
- Do you agree with our initial proposal (i.e. Option 3 complemented by a discretionary reward scheme)?
- Do you consider our proposed method to implement Option 6 appropriate (i.e. through GDNs' connection charging statements)?
- Do you consider the Government's Index of Multiple Deprivation to be an appropriate index to identify which fuel poor non-gas communities qualify for special treatment for gas network extensions? If not, what do you recommend?
- Do you support our proposals for the introduction of a Discretionary Reward Scheme (DRS) for GDNs and its format given the larger reward?

Views of GDNs

1.84. The GDNs agree with Ofgem's proposal for network extensions, i.e. option 6 with an incentive scheme. However, two GDNs consider that committed funding needs to be made available, and the other two consider the discretionary reward scheme (DRS) to be insufficient as an incentive scheme for network extensions. One of the GDNs suggested a methodology: include an annual allowance; include an adjustment mechanism to allowed revenue; and, allow actual costs of connection into the RAV immediately with an ex post review to determine efficiency of expenditure.

1.85. Two GDNs expressed support for Ofgem's proposed method to implement option 6 for network extensions appropriate, i.e. through GDNs' connection charging statements.

1.86. In general, the GDNs consider the Government's Index of Multiple Deprivation (IMD) to be an appropriate index to identify which fuel poor non-gas communities qualify for special treatment for gas network extensions.

1.87. Overall, the GDNs support Ofgem's proposals for the introduction of a DRS.

Views of other respondents

1.88. All non-GDN respondents agree with Ofgem's proposal for network extensions.

1.89. In general, the non-GDN respondents consider the IMD to be sensible but had some concerns. They had the following specific responses to the IMD: that it is not refined enough; we should use a lower cut-off; we should consider the fuel poverty indicator; and, we should focus on the income and employment domains rather than the overall IMD.

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

Ofgem's views

1.91. The purpose of the incentive scheme is to encourage GDNs to find ways to increase the affordability of network extensions to non-gas fuel-poor communities through coordinating various sources of government funding. The incentive scheme is not meant to represent an operating cost allowance to cover the costs of the activity.

1.92. As part of our proposals, we have taken into account capital charges for carrying out network extensions. In the main document, we have proposed that allowances from network extensions be capitalised and added to the GDNs' RAV, with capital charges incurred over the price control being recovered on an NPV-neutral basis as part of the subsequent price control allowance.

1.93. One GDN suggested we include a revenue driver based on appropriate parameters however the costs involved in network extensions do not justify the complexity associated with implementing a revenue driver.

1.94. The latest versions of the IMDs are calculated at the Lower Layer Super Output (LSOA) level (in England and Wales) and the Data Zone level (in Scotland), which represent smaller areas than the Local Authority level, and are officially recognised so we consider these levels to be adequate.

1.95. Currently, the fuel poverty indicator does not exist for all areas so we continue to consider the IMD a sensible index to use to identify eligibility for the network extension options as there is a separate one for each area, i.e. England, Scotland and Wales. We acknowledge that the IMD is not a perfect proxy for fuel poverty however analysis done by the Department for Business, Enterprise and Regulatory Reform (BERR) indicates that it is highly correlated with fuel poverty. The IMD is the best available proxy and is accessible for each country.

1.96. Finally, using only the income and employment domains will not capture all types of deprivation. For example, there is a housing domain in the Scottish and Welsh IMDs and a living environment deprivation domain in the English IMD which all include a 'house without central heating' indicator.

1.97. We consider that £4 million per year for the five year period for the DRS to be a reasonable amount. The focus of the scheme and the weighting of the reward across the categories will be decided by Ofgem, in conjunction with the Panel, at the start of each year. Consideration will be given to the respondents' views when deciding the focus.

Responses to Chapter 8 - Other issues

1.98. This chapter described other issues that make up the price control package and included our proposals on the funding of xoserve and also next steps on arrangements for independent systems. Respondents were asked the following questions:

- Do you agree with our proposed approach to the funding of xoserve?
- How should we address any benefits arising to xoserve from redundancy created from the replacement of UK Link?
- Do you agree with our approach of modifying SSC A15 to facilitate governance arrangements for user-pays?
- Do you think that the existing arrangements are adequate to ensure enforcement of the range of services and outputs delivered by xoserve in light of these proposals?

Views of GDNs

1.99. All of the GDNs expressed some support for the user pays approach to fund xoserve. However, one GDN considers it unlikely to change significantly the way xoserve is funded in the short or medium term. Another GDN supports user pays provided that it is funding incremental costs and all fixed unavoidable costs are fully funded by price control allowances. A GDN considers that the proposals have some way to go before concerns are addressed, and another GDN has reservations around its implementation.

1.100. While one GDN considers that benefits arising to xoserve from redundancy created from UK-Link replacement should be addressed ex-post, three GDNs do not think there will be any redundancy.

1.101. One GDN sees no need to modify SSC A15 to facilitate governance arrangements for user pays however changes to other licence conditions may be required. Another GDN agrees with Ofgem’s approach and notes that other licence conditions may also need amendment. A GDN is concerned that transporters will be exposed to additional costs of system changes initiated by other users, and notes that governance arrangements are key to this.

1.102. All of the GDNs think that the existing arrangements are adequate to ensure enforcement of the range of services and outputs delivered by xoserve in light of proposals.

Views of other respondents

1.103. One non-GDN respondent agrees with the proposed approach to the funding of xoserve, while another thinks further work is needed. Two non-GDNs are not entirely convinced over the proposed approach however one of them supports the proposed approach over maintaining the existing funding structure. Another non-GDN does not agree with pursuing user pays at this time. Two non-GDNs think user pays has merit but as currently expressed it is unlikely to have any effect on demand.

1.104. Two non-GDNs consider that benefits arising to xoserve from redundancy created from UK-Link replacement should be addressed ex post. Two other non-GDNs do not believe that excessive redundancy will be built into replacement.

1.105. Most non-GDN respondents agree with Ofgem’s approach of modifying SSC A15 to facilitate governance arrangements for user-pays.

1.106. In general, four non-GDNs consider the existing arrangements to ensure enforcement of the range of xoserve services to be adequate however two do not.

Ofgem's views

1.107. 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 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 and 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 is establishing a work programme to take this forward.

1.108. 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 (ref. 221/07). 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.

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

1.110. 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 and user pays arrangements do not affect the continued performance of xoserve.

Responses to Chapter 9 - Financial issues

1.111. Chapter 9 set out Ofgem's proposals on the cost of capital and tax, and discusses the initial outcomes of our financeability review. Respondents were asked following questions:

- What are your views on the factors relevant to our consideration of cost of capital?
- Are the factors affecting financeability set out in paragraph 9.36 the responsibility of shareholders or the regulator to address and how should they be addressed?

Views of GDNs

Cost of capital

1.112. One GDN says that the key factors in the consideration of cost of capital include market evidence on the building blocks of the CAPM model, previous regulatory determinations, and any asymmetric risks associated with the regulated package. This GDN has in the past supported the use of long-term trailing averages for setting the cost of debt, but now believes that spot rates are rising above such trailing averages and so the base figure to build in the debt allowance is the current spot rate, with additional allowance for anticipated further increases and interest rate volatility. This GDN expects allowance for cost of debt to be greater than 4.1 per cent, and considers the cost of equity in TPCR to be an appropriate starting point for GDPCR, with adjustments for risk differentials between transmission and distribution and gearing differences. This GDN then goes on to argue that the terminal risk associated with gas distribution is greater and this should be reflected in shorter asset lives or additional return.

1.113. Another GDN agrees with the CAPM approach but thinks the parameters used by Ofgem in their modelling assumption are inappropriate and would lead to an unacceptable cost of capital.

1.114. A further GDN considers the cost of capital used as Ofgem's modelling assumption to be significantly below the level required to provide a robust financial basis for a gas distribution business. This GDN says that the debt capital market conditions have changed materially during the past 9 months with the risk free rates and credit spreads much higher. It considers that a cost of equity of at least 7.5 per cent post-tax WACC can be supported by academic evidence and advocates use of the Dividend Growth Model as a cross-check. Based on their parent companies' stated dividend policy, they estimate the cost of equity to be 8 per cent.

1.115. The final GDN considers that it would be imprudent to assume that cost of debt for the future price control period to 2013 will continue to decline, and sees problems in adopting a cost of debt within WACC based on a debt index or adjusting WACC during or after a price control period if movements in a debt index exceed trigger points. In terms of cost of equity, this GDN says that the risk in distribution is greater than in transmission so an accurate comparative risk analysis is important to establish the appropriate WACC. It also considers that if notional gearing is increased then Ofgem will have to address this impact on cost of debt and equity.

1.116. In addition to their individual submissions, the GDNs jointly commissioned an analysis of risk differentials between transmission and distribution. Oxera have also produced two other reports for the GDNs; one on market / RAV differentials, and one on market evidence for the inputs to the cost of capital calculation. An outline of Oxera's reports and our critique of them can be found in appendix 16.

Financeability

1.117. All the GDNs have highlighted the low levels of PMICR (post-maintenance interest cover ratio) generated in Ofgem's financial model. They argue that the assumption that a company with such low ratios would take the rational step of index-linking a modest proportion of debt conflicts with regulators' preference to avoid seeming to be prescribing the appropriate capital structure. One GDN goes so far as to say that such an approach increases regulatory uncertainty and thus increases the required cost of capital. Some of them note that they have debt covenants that utilise this ratio.

1.118. Two GDNs addressed the specific question of which sources of poor ratios are the regulators' responsibility to take into account when reviewing financeability. One GDN said that as the GDNs had no control over the sculpting of the RAV, that to the extent this led to short-term financeability issues for some GDNs, Ofgem should be prepared to make financeability adjustments. The other GDN argued that to the extent any of the three sources mentioned (pot 2 penalties, IQI penalty, RAV sculpting) led to poor ratios, Ofgem should make appropriate financeability adjustments.

Views of other respondents

1.119. One non-GDN respondent agrees with many elements of Ofgem’s consideration of cost of capital but thinks that Ofgem has not taken sufficient account of evidence presented by CEPA, and so the proposals risk granting windfall gains to GDNs through too high a WACC. Another non-GDN’s main concern relates to the estimation of cost of capital and the apparent regulatory 'opportunity' provided by historically low bond yields. This non-GDN urges Ofgem to take a long term view of funding cost of capital consistent with long term investment that companies are expected to make in their networks. Another non-GDN considers that the approach to gearing should be consistent with ensuring that sufficient levels of equity continue to be invested in networks. A further non-GDN sees no case for a modelling assumption for the cost of debt that is 20 basis points lower than that used at the time of TPCR. Finally, a non-GDN considers the 4.84 per cent vanilla WACC very low and unlikely to attract investors to fund infrastructure renewal. This non-GDN considers the reduction of cost of debt to 3.55 per cent very bold given the movement of interest rates over the past six months.

Ofgem's views

1.120. A detailed update of our views on the cost of capital can be found in chapter 9 and appendix 16.

1.121. As we outlined in initial proposals, Ofgem's assessment of the cost of debt draws on many factors, but in recent reviews, we have tended to place more weight on debt costs over the longer term, rather than relying on the snapshot provided by the latest market information. As a result, the argument that we should start with the TPCR cost of debt and adjust upwards for changes in spot rates is flawed, since it incorrectly presumes that the TPCR figure was based substantially on spot rates in November 2006.

1.122. We have attracted some criticism for our long-term approach, the argument being that we have failed to secure the benefits for consumers of the historically low recent debt yields. Our view has been that these conditions might not be expected to last indefinitely, and that it was better to signal a consistent regulatory approach that led to a relatively stable cost of debt figure. This regulatory certainty, if maintained over a number of reviews, should ultimately allow us to set a marginally lower cost of capital than otherwise.

1.123. It would in contrast be detrimental to customers' interests to adopt the asymmetric approach suggested by one GDN respondent of taking a long term view when current rates were lower than long-term averages, but reverting to current rates as a benchmark when they were higher. On the other hand it would also be against customers' interests if companies were unable to raise finance for investment because the cost of capital allowance was insufficient to cover debt costs.

1.124. We would reiterate that a final decision is yet to be made on the cost of debt (along with the other parameters of the cost of capital). However, taking the current modelling assumption as a benchmark, we have modelled companies' sensitivities to changes in debt costs based on their current actual debt profile. As the IDNs were originally financed during the period with low yields, they have relatively low embedded debt costs, except to the extent they have chosen to finance themselves at floating rates. NGG has also been able to finance itself at comparable rates. Since the cost of capital is applied to the whole of the RAV, not just the incremental expenditure, this means that interest rates could rise substantially from their current level, before the cost of debt used in the modelling assumption ceased to be sufficient to cover total interest costs. We are satisfied therefore that our range for the cost of debt is plausible even in the context where interest rates have risen recently. In any case spot rates and ten year trailing average rates are still lower than our modelling assumption.

1.125. Our assessment of risk differentials and their impact on the cost of equity are set out in chapter 9 and appendix 16. With reference to the dividend growth model, there is a lack of specific market evidence relating to gas distribution, so at best the overall picture for utilities can give a very broad sense check, rather than provide support for a specific figure within an overall range. With reference to CEPA's analysis[1], their estimate of the cost of equity of 6.5 to 7 per cent was based on three main factors:

- a perceived fall in the required cost of equity resulting from the same global liquidity that has led to recent low debt costs;
- valuations of regulated companies and recent asset transactions suggesting a consistent premium to the RAV; and
- evidence that infrastructure funds in particular require a lower rate of return than Ofgem's range.

1.126. As with the cost of equity, Ofgem has indicated its preference to put more weight on long-term indicators. For this reason, we do not think it would be appropriate to rely overly on current market measures, particularly when there have been recent signs that the prevailing market conditions have shifted towards higher returns.

1.127. Since Ofgem does not assume a particular capital structure when setting the cost of capital, it also follows that it would not be appropriate to assume a particular ownership model, particularly when in practice, the gas distribution sector is characterised by a mixture of public and private equity.

1.128. The GDNS' responses in respect of financeability suggest a misunderstanding of the way in which Ofgem approaches financeability. Firstly, we have made it clear that we base the assessment on a range of ratios, and it is not necessary to meet indicative targets on all of them, as long as most of them are met. We consider that this approach is broadly in line with the assessments that would be made by the major rating agencies in respect of a company at similar gearing levels to those assumed in our model.

1.129. Ofgem's financeability assessments may be satisfied where we can be reasonably confident that there are steps that could reasonably be taken by the GDNS to improve ratios. The relatively low PMICR values are in the context of an assumption of 100 per cent nominal debt, and can be mitigated by recourse to the index-linked debt market. Suggestions that this represents an attempt by Ofgem to dictate the GDNs' capital structure are erroneous - we simply note that this is a

[1] CEPA - The allowed cost of capital, cost of equity section update, Ofgem: GDPCR 2008-13, July 2007

rational solution to the challenge of maintaining an adequate PMICR, not necessarily the only one. It is clearly an approach that has enjoyed widespread use in the sectors where PMICR is a key ratio, namely water and gas distribution. Indeed, one estimate is that 31 per cent of UK utility debt is index-linked[2]. Since most of the GDNs have already a substantial amount of index-linked debt, the possibility raised by some of them that the demand for such debt may dry up does not seriously undermine this approach.

[2] CEPA, Risk adjusted cost of capital for Network Rail, June 2007, available at http://www.rail-reg.gov.uk/upload/pdf/pr08-cepa-risk-jun07.pdf

Appendix 6 - Benchmarking, real price effects, regional factors and efficiency

Real price effects

1.1. 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 consider 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 considered additional evidence from other sources. We consider that there is sufficient evidence to support our initial assumptions and therefore maintain that view.

Direct Labour

1.2. For initial proposals we considered a range of evidence on real growth in salaries and earnings, including work carried out as part of TPCR and more recent information. The information is shown in table A6.1 below.

Table A6.1 - Summary of real growth in salaries and earnings

		%
1	Private sector average to Mar 06[3]	1.7
2	IDS average 6mths to Sept 06[4]	0.9
3	SSE recent pay settlement[5]	0.6 to 1.3
4	NGG recent pay settlement[6]	0.6
5	Utility sector average Apr 05-Apr 06[7]	0.4 to 1.4
6	Hay report (NGG commissioned)[8]	1.6
7	HM Treasury[9]	1.6
8	Inbucon (TPCR commissioned)[10]	1.0
9	Ernst and Young ITEM Club[11]	1.1
10	Annual Survey of Hours and Earnings[12]	1.1

[3] National Grid: Business Planning Process - Real Pay Growth, June 2006
[4] Income data Services Pay reports - Average earnings Index (including bonuses) less RPI
[5] Income Data Services: Pay Report 934 August 2005
[6] Income Data Services: Pay Report 941 November 2005
[7] Income Data Services: Pay Report 951 April 2006
[8] National Grid: Business Planning Process - Real Pay Growth, June 2006
[9] HM Treasury Forecasts for the UK Economy, November 2006
[10] TPCR & GDPCR Employment Cost Benchmark, October 2006
[11] Ernst & Young ITEM Club findings for the year to November 2006
[12] Annual Survey of Hours and Earnings (ASHE), April 2006

1.3. This data shows real growth in salaries and earnings ranging from 0.4 to 1.7 per cent per annum with recent utility settlements within a slightly lower range. On this basis we concluded that an assumption of real growth of earnings of 1 per cent per annum was appropriate.

Responses by the GDNs

1.4. The GDNs argue that an assumption of 1 per cent growth in real earnings is inappropriate. WWU has reviewed data from three sources: the BCIS indices; the National Statistics Digest; and, the DTI Monthly bulletin from 2003-04 to 2006-07. WWU notes that this shows average real growth in earnings of between 0.9 per cent and 3.6 per cent with an average of 2 per cent. The Chandler KBS report commissioned by WWU concluded that real growth in earnings of 1.8 per cent was appropriate for the next price control period.

1.5. SGN argues that the assumption for real growth in earnings should be 1.9 per cent. The Deloitte's report[13] it commissioned suggests that Ofgem has placed too much emphasis on recent growth in earnings and insufficient evidence on forecasts. It notes that both the June 2007 HM Treasury Forecasts for the UK economy and the Hay report commissioned by NGG suggest real growth rates of approximately 1.6 per cent. It indicates that the Deloitte's report for the Office of Government (OGC)[14] concludes that wages for skilled workers will increase on average by 3.9 per cent per annum during the next ten years. With inflation estimated to be in the range of 2 per cent to 2.5 per cent, this implies real growth in earning of 1.4 per cent to 1.9 per cent.

1.6. NGG has raised a number of issues with the data that Ofgem has used to support its assumptions on real growth in direct labour costs. It notes that a number of the indices reflect base annual salary increases rather than real growth in earnings. Pay settlement data does not take into account payments for performance and promotion etc. NGG is concerned that the quoted sources are a mixture of historical, future and point- in-time findings. It notes that there should be focus on longer-term trends. The Hay and Imbucon reports suggest average real growth of 1.7 to 1.9 per cent. The HM Treasury forecast for real average earnings growth in 2008 is 1.8 per cent. NGG indicates that other information in the Imbucon report suggests real earnings growth of 3 per cent.

1.7. NGG accepts that the Hay report concludes that future real earnings growth is around 1.6 per cent per annum. But Hay also indicates that there are a number of industry specific factors such as unionisation and skill shortages that are likely to lead to higher levels. Hay has recently updated its work and concludes there is no change. Based on this evidence NGG still considers 2 per cent to be appropriate.

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[13] "A report to SGN on the Assumptions in Ofgem's initial proposals on regional factors and real price effects" Deloitte & Touche, July 2007

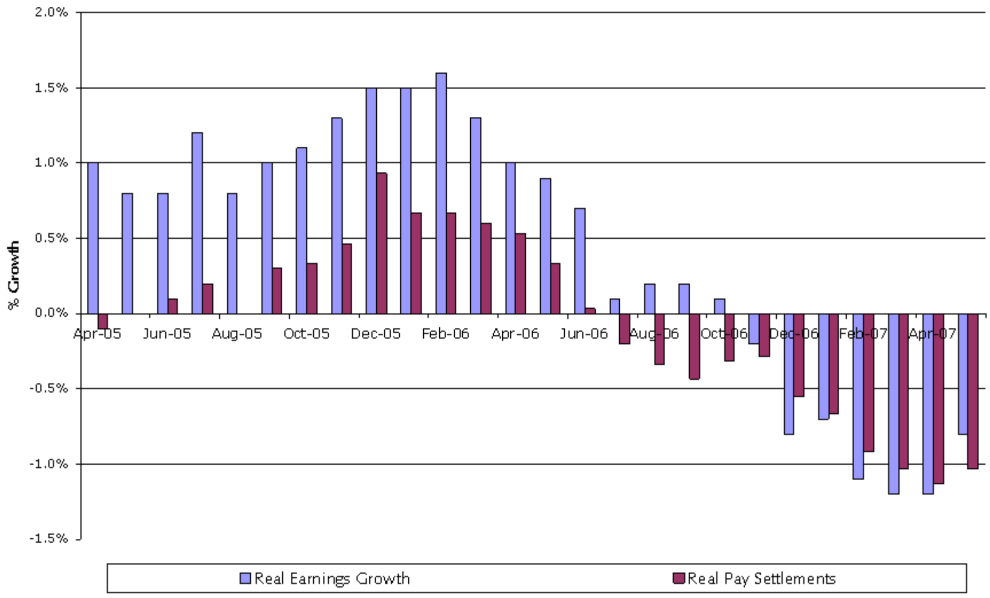
[14] "2005-15 Construction Demand/Capacity Study - Full Report", Deloitte & Touche on behalf of Office of Government Commerce, 2006

1.8. NGN notes that there are several specific industry factors that are driving wage increases for GDNs such as skill shortages and the ageing workforce. It notes that in March 2007, IDS reported that pay settlements in the UK had reached a six year high. NGN indicates that construction industry wage settlements have averaged between 4.1 per cent and 4.7 per cent (in nominal terms) over the last 5 years supporting its assumption of 2 per cent.

Other evidence

1.9. We have collected further evidence on real input prices. Figure A6.1 below shows real earnings growth for the whole economy based on ONS survey data. This includes basic pay, overtime, shift payments and profit-related pay. It also shows median real pay settlements from the IDS Pay Databank. This only includes basic pay. Real growth varies from -1.1 to 1.6 per cent.

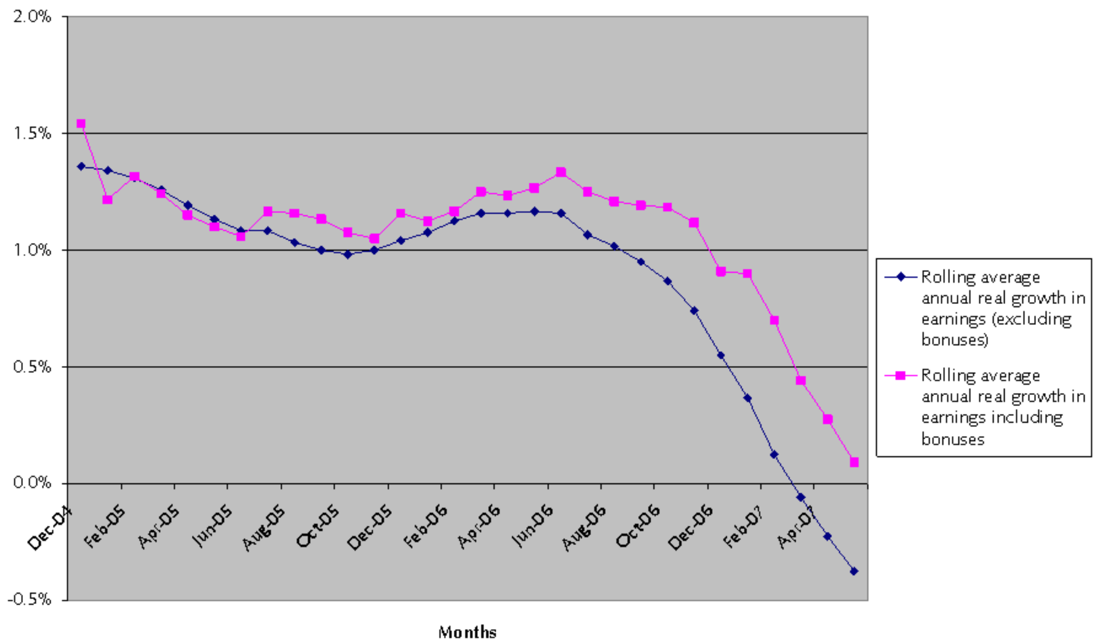
Figure A6.1 - Real growth in earnings and pay settlements[15]



1.10. This appears to show a shift from real pay growth during 2005 and the first half of 2006 to real pay decreases. Figure A6.2 below shows the rolling annual average growth in real earnings both including and excluding bonuses from the IDS report data. Again this highlights declining real wage growth.

[15] Ofgem calculations based on information of pay settlements and growth in average earnings (excluding bonuses) published in the Income Data Services pay reports.

Figure A6.2 – Rolling average real growth in earnings[16]



1.11. The July 2007 IDS pay report (980) considers pay deals in the utilities sector. It notes that pay deals in the energy sector have tended to be at the higher end of the range due to levels of unionisation and skill shortages and pay deals traditionally being linked to the upper quartile of average earnings.

1.12. It indicates an average level of increase in pay in the utilities in the early part of 2007 of 4.4 per cent and a median increase of 4.2 per cent. With RPI of around 4.2 per cent over the same period, this suggests that pay deals are keeping pace with or are slightly ahead of inflation. The second year of NGG's pay deal to be implemented in July 2007 is at RPI plus 0.3 per cent. The second year of SSE's three year pay deal is at RPI plus 0.6 per cent.

Conclusions on real growth in earnings

1.13. The evidence put forward to date suggests real growth in earnings of between 0 per cent and 3.5 per cent, with the majority of recent evidence pointing towards the lower end of this range. The evidence of higher rates of growth is typically based on longer-term trends. We note that the Deloitte report for the OGC concludes that real growth in wages for skilled labour in construction will be between 1.4 and 1.9 per cent based on nominal growth of 3.9 per cent and inflation in the range of 2 to

[16] Ofgem calculations based on data published in the Income Data Services pay reports.

2.5. The inflation figures used are based on CPI and RPI X which will result in earnings growth being overestimated relative to RPI.

1.14. On this basis we consider that the existing assumption of 1 per cent is reasonable and have maintained it for updated proposals.

Contract Labour

Initial proposals

1.15. Our assumption of 2 per cent real growth in contractors' rates in initial proposals was based on the Baxter Civil Engineering Index and the EC Harris Tender Price Index (TPI) following the approach put forward by NGG.

1.16. The Baxter Index is the index most commonly used for gas distribution engineering contracts. On average, between 2000 and 2006, real growth in the Baxter index was 0.8 of a percentage point above the national TPI index. Our analysis of the EC Harris National TPI showed average real growth of 1.1 per cent per annum between 2006 and 2012. Applying the 0.8 percentage point uplift to real growth in the EC Harris index of 1.1 per cent gives a real price effect of around 2 per cent per annum.

Responses by the GDNs

1.17. NGG has updated the analysis used in initial proposals to derive the real growth in contractors' rates. This now shows a 1.13 per cent differential between Baxter and the EC Harris TPI and 1.95 per cent real increase in the TPI. This gives an assumption of 3.08 per cent. NGG also notes that the latest EC Harris forecasts suggests an average differential in real price growth between London and the rest of the country of 1.67 per cent. On this basis NGG considers real price growth of 4.75 per cent appropriate for London.

1.18. SGN considers that real price growth of 4.5 per cent per annum is appropriate in London, with 3.9 per cent for the South-East and 3.2 per cent for the rest of the country, based on work carried out by Deloitte on their behalf. The Deloitte report argues that there should be a regional uplift on contract labour wage growth for London of 0.9 to 1.6 per cent over the period 2008 to 2012. They have quoted the summer 2007 EC Harris Economic Survey: "as more Olympic schemes come through, they will be competing with the very busy commercial market for a limited supply of labour and materials".

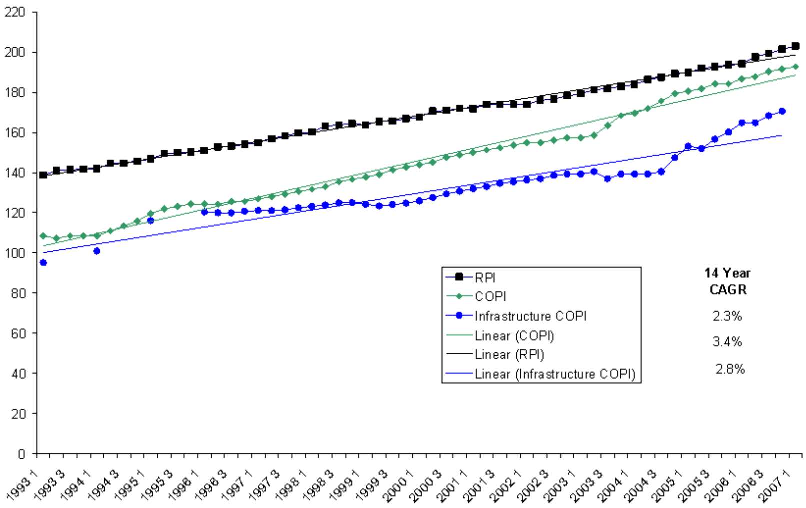
1.19. WWU has reviewed historical real growth in the Baxter index over the past five years and considers that real growth of 3.6 per cent is appropriate.

1.20. NGN notes that the historical relationship with the Baxter index and the TPI is not necessarily a good guide to future conditions. It points out the number of large construction projects over the next price control period and that the February BCIS newsletter suggests real price growth of 3.6 per cent in 2008. NGN also notes that updating the initial proposals methodology leads to an assumption of around 3 per cent growth in contractors' rates.

Additional evidence

1.21. We have reviewed long-term trends in infrastructure and construction price inflation based on DTI data as shown in figure A6.3 below. Over the past 14 years the average real growth in infrastructure prices has been 0.5 per cent, although there appears to have been an upturn from 2004-05 of around 1 per cent.

Figure A6.3 – Construction Price Inflation



Source: DTI Output Price Indices, Construction Statistics Annual

1.22. Deloitte's June 2006 report for the OGC suggests that construction price inflation, on average, has been 1.9 per cent higher than RPI since 2000. It notes that activity levels in the construction industry in Greater London have been lower than the rest of the country as a result of weaknesses in the commercial sector. It also indicates that between 2000 and 2005 construction Tender Price Inflation for Greater London has been 5.7 per cent compared to 6.7 per cent nationally. The Deloitte report states that several ongoing large projects are scheduled to wind-down prior to commencement of the London Olympics work, releasing resources but this may change.

Conclusions on real growth in contractor rates

1.23. Longer-term evidence on real growth in contractors' rates suggests real price rises of less than one per cent. However, the latest Deloitte's work and Baxter/EC Harris indices based on shorter-term trends in data would suggest real growth of around 3 per cent or higher. Overall we consider that our 2 per cent assumption is appropriate in light of the evidence and provides the basis for updated proposals.

1.24. We do not consider that an ongoing differential in real growth in contract prices between London and the rest of the country is sustainable as this would attract additional labour from other regions into London. An example is the analysis of the historical TPIs in the June 2006 Deloitte report for the OGC[17] which supports this. It shows that there are cycles in tender prices in both London and the rest of the country and that the growth in construction prices in London will exceed other parts of the country in the peak of the cycle but be lower in London in the downturn of the cycle.

Materials

Initial proposals

1.25. We based our assumption of 1 per cent growth in materials prices on the Building Construction Information Service (BCIS) Quarterly Review from 2006 and the Penspen report commissioned as part of TPCR, which both forecast that materials costs would flatten out during 2007.

GDN responses

1.26. WWU has indicated that DTI bulletin data shows real price growth of 1.6 per cent. NGN notes that material costs have been rising at an average of 5 to 6.4 per cent for the last four years and considers a 2 per cent assumption appropriate.

Conclusions on real growth in material prices

1.27. We do not consider that there is sufficient evidence, at this time, to support a move away from our assumption at initial proposals. We still consider an assumption of 1 per cent real growth in materials costs appropriate.

On-going productivity savings

1.28. Our assumption for ongoing productivity savings in initial proposals was 2.5 per cent per annum based on Europe Economics work and an assumption of 1.1 per cent efficiency savings per annum due to comparative competition.

1.29. The GDNs have raised a range of concerns with this work, including the data being out-of-date. They have also said that it has not been 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.

1.30. The First Economics' work, commissioned by the GDNs, suggests that there is no need for analysis of productivity trends to estimate the scope for improvements in efficiency by GDNs, as there is a simpler and more robust approach which looks at

[17] "2005-15 Construction Demand/Capacity Study - Full Report", Figures A6.3 and A6.6, Deloitte on behalf of Office of Government Commerce, 2006

the contributions different sectors make to the change in RPI. According to First Economics, those sectors most comparable to the GDNs have seen costs rise at around 2 per cent per annum faster than the RPI. After allowing for the effects of comparative competition and capital substitution, First Economics' results suggest that operating costs will rise at 0 to 0.5 per cent per annum.

1.31. We have commissioned additional work in this area by Reckon LLP. They recognise some weaknesses in the Europe Economics' analysis but do not consider that the First Economics' work is an adequate alternative. It has a number of weaknesses; not least that it measures the wrong thing. Consumer prices capture changes in profits and capital employed as well as productivity. They also reflect end-products and services rather than intermediate services such as gas distribution.

1.32. Reckon LLP has updated the TFP analysis to use a new dataset published this year which runs up to 2004 and corrects the errors in Europe Economics' analysis. The results of Reckon LLP's work are set out in the table below.

Table A6.2 - Productivity growth for comparator sectors based on value added

Sector	Productivity Growth
Construction	1.5%
Financial intermediation including banking & insurance	0.1%
Manufacture of chemicals, chemical products and man-made fibres	4.8%
Sale, maintenance and repair of motor vehicles and motorcycles; resale of automotive fuel	2.4%
Transport and Storage	2%

1.33. If we adopt a figure of 1.4 per cent (towards the lower end of the range in the table above) and then add our 1.1 per cent productivity assumption for comparative competition, which we used for DN sales, this would support ongoing productivity of 2.5 per cent.

1.34. We have therefore retained the 2.5 per cent productivity assumption for updated proposals.

Appendix 7 - Opex

Direct opex

1.1. In initial proposals, we presented bottom up allowances based on PB Power's analysis, adjusted for our own assumptions. Since initial proposals, PB Power have updated their analysis using 2006-07 actual cost data from the GDNs and taking account of comments received on initial proposals.

1.2. PB Power also reviewed the approach to the maintenance activity and adopted an approach based on an analysis of total recurring maintenance costs, rather than the previous approach using separate analysis for LTS maintenance, storage maintenance and other maintenance.

1.3. PB Power's analysis was then modified to take account of our own view of factors such as real price effects and ongoing efficiencies, as well as reducing PB Power's assumptions for reductions in the number of PREs and repairs as a result of the mains replacement programme. We have also modified the CSV used in the total maintenance analysis to reduce the number of variables it depended on.

1.4. The following table sets out the results of updating our analysis for the impact of using 2006-07 actual data as well as the impact of methodology changes and revised assumptions.

Table A7.1 - Results based on 2006-07 actuals, methodological changes and revised assumptions

	NGG				NGN	SGN		WWU	Total GDN	Average annual GDN spend
Ofgem Initial Proposals	**East of England**	**London**	**North West**	**West Midlands**	**Northern**	**Scotland**	**Southern**	**Wales & West**		
Work Management	126.9	81.7	97.5	67.9	99.7	72.5	155.9	97.3	799.5	20.0
Emergency	55.2	43.5	44.6	23.6	41.6	31.0	82.9	36.5	358.9	9.0
Repair	42.3	42.8	40.4	28.9	41.8	32.3	83.2	40.0	351.8	8.8
Maintenance	62.4	42.4	45.4	41.2	58.3	29.4	44.2	62.5	385.8	9.6
Other Direct Activities	11.9	4.5	7.6	5.2	8.0	5.0	11.3	7.6	61.1	1.5
Xoserve	23.8	11.8	15.6	13.1	14.6	9.7	22.0	14.0	124.6	3.1
LNG to SIUs	0.0	0.0	0.0	0.0	0.0	24.0	0.0	0.0	24.0	0.6
Total Direct Opex	**322.6**	**226.9**	**251.1**	**179.8**	**264.0**	**203.9**	**399.6**	**257.8**	**2,105.6**	**52.6**
Update for 2006-07 Actuals										
Work Management	109.9	81.0	89.0	67.6	90.5	69.8	136.8	88.5	733.0	18.3
Emergency	54.1	45.3	46.0	30.7	43.7	35.2	74.4	38.9	368.2	9.2
Repair	45.0	41.1	43.1	32.4	44.2	34.6	83.0	41.5	364.8	9.1
Maintenance	63.1	42.4	45.0	41.7	59.0	28.7	42.7	62.4	385.0	9.6
Other Direct Activities	13.3	4.6	8.1	5.1	8.6	4.8	12.9	8.1	65.5	1.6
Xoserve	24.1	11.7	15.6	13.1	14.6	9.7	22.0	14.0	124.7	3.1
LNG to SIUs	0.0	0.0	0.0	0.0	0.0	24.0	0.0	0.0	24.0	0.6
Total Direct Opex	**309.5**	**226.0**	**246.8**	**190.4**	**260.6**	**206.7**	**371.8**	**253.4**	**2,065.2**	**51.6**
Ofgem Updated Proposals										
Work Management	108.8	82.3	88.8	64.5	92.6	66.2	140.0	81.1	724.4	18.1
Emergency	54.1	44.9	44.4	28.8	42.2	32.6	74.5	34.6	356.2	8.9
Repair	44.5	48.9	45.5	34.0	50.4	35.0	94.5	44.0	396.7	9.9
Maintenance	65.8	49.7	54.1	46.6	46.8	38.3	64.4	57.4	423.2	10.6
Other Direct Activities	11.2	6.6	5.9	5.1	9.0	4.8	13.1	10.8	66.5	1.7
Xoserve	20.7	12.1	14.6	12.2	13.6	9.1	20.6	13.1	116.0	2.9
LNG to SIUs	0.0	0.0	0.0	0.0	0.0	24.0	0.0	0.0	24.0	0.6
Total Direct Opex	**305.2**	**244.6**	**253.3**	**191.2**	**254.7**	**210.0**	**407.1**	**240.9**	**2,106.9**	**52.7**
% change from initial proposals	*-5.4%*	*7.8%*	*0.9%*	*6.3%*	*-3.5%*	*3.0%*	*1.9%*	*-6.6%*	*0.1%*	*0.1%*

Revised workload assumptions

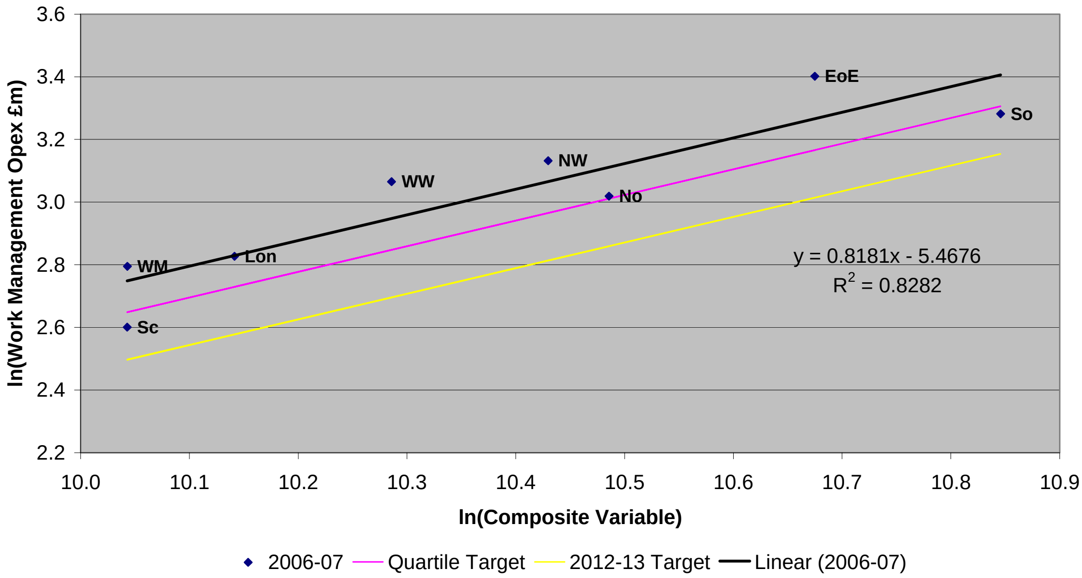
1.5. Our analysis for initial proposals assumed that external PREs would reduce by 1.8 per cent per annum and internal PREs would remain flat. We assumed that condition based repairs to mains and services would reduce by 3 per cent per annum due to the mains replacement programme. The historical data 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.

Work management

1.6. The work management analysis has not significantly changed since initial proposals. The costs allocated to this activity in 2006-07 for both of SGN's DNs have reduced significantly since 2005-06 costs due to the reallocation of costs that had previously been incorrectly included in work management to other activities. In particular, in 2005-06 costs for some staff such as maintenance technicians had been re-allocated to work management. This has been reversed for 2006-07. In addition some general support service costs were included in work management rather than indirect costs and recharges of supervisory costs were included in repairs. These allocations had resulted in over-inflating SGN's 2005-06 work management costs.

With these connections applied SGN is now an out-performer on this activity. This has the effect of reducing the upper quartile level of costs.

Figure A7.1 - Revised work management regression using 2006-07 actuals



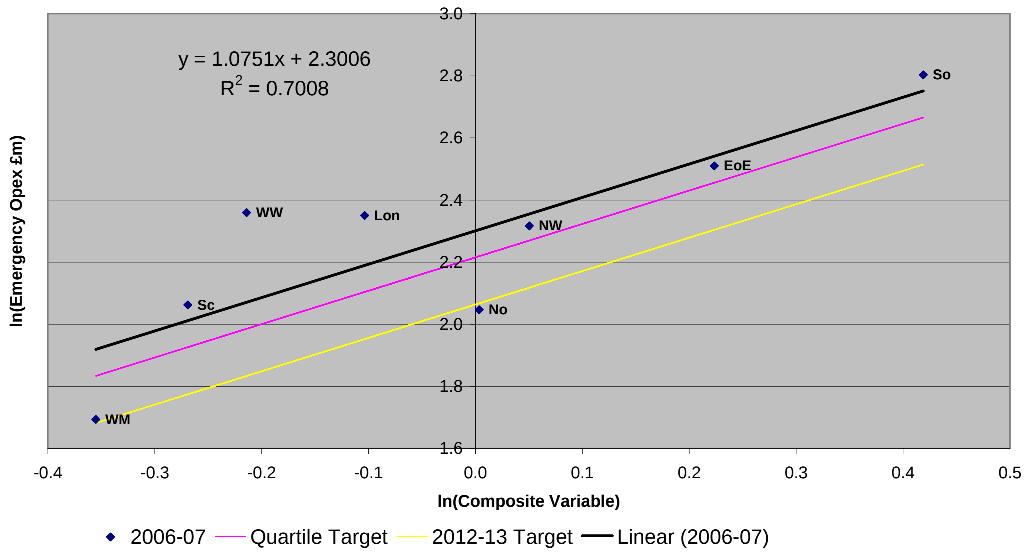
Emergency

1.7. PB Power's analysis for emergency costs has been updated for 2006-07 actual costs and modified to use a log-linear rather than a linear regression. In their original analysis, PB Power also transferred costs from repex to emergency for First Call Operative attendance at service relays. PB Power has reviewed this transfer and concluded that it is not appropriate. The amount of this transfer varied between GDNs but on average had increased emergency costs by about £1.2m per annum per GDN.

1.8. In initial proposals, we considered that the 2005-06 emergency service costs represented a reasonably consistent position across all GDNs regarding the level of meterwork undertaken by each GDN, and that, where there were differences in meter workload, these were reflected in different levels of contractor costs being allocated to non-formula activities. Information supplied by GDNs indicates that in some networks the meter workload was sufficiently lower in 2006-07 than in 2005-06 to increase the costs of the emergency activity (net of meterwork), and that these additional costs have been reported in the 2006-07 actuals. To carry out the comparative analysis of the emergency activity across all GDNs on a consistent basis, the additional costs reported by GDNs as arising from the loss of meterwork has been removed as part of the normalisation adjustments applied to the 2006-07 costs.

1.9. The following figure shows the revised regressions obtained with 2006-07 actuals.

Figure A7.2 - Revised emergency regressions using 2006-07 actuals

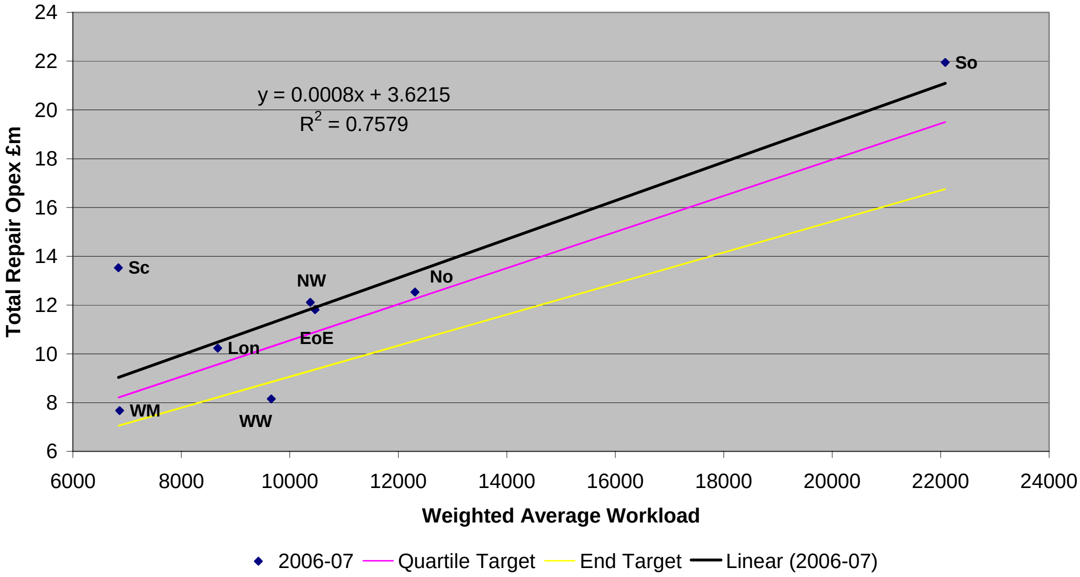


Repair

1.10. The updated repair analysis is based on the same regressions as used in initial proposals, but updated to use 2006-07 data rather than 2005-06 data. All GDNs except Wales and West showed increased costs in this activity, resulting in a slight increase in the regression line from previous analysis.

1.11. The following figure shows the revised repair regressions obtained with 2006-07 actuals.

Figure A7.3 - Revised repair regressions using 2006-07 actuals

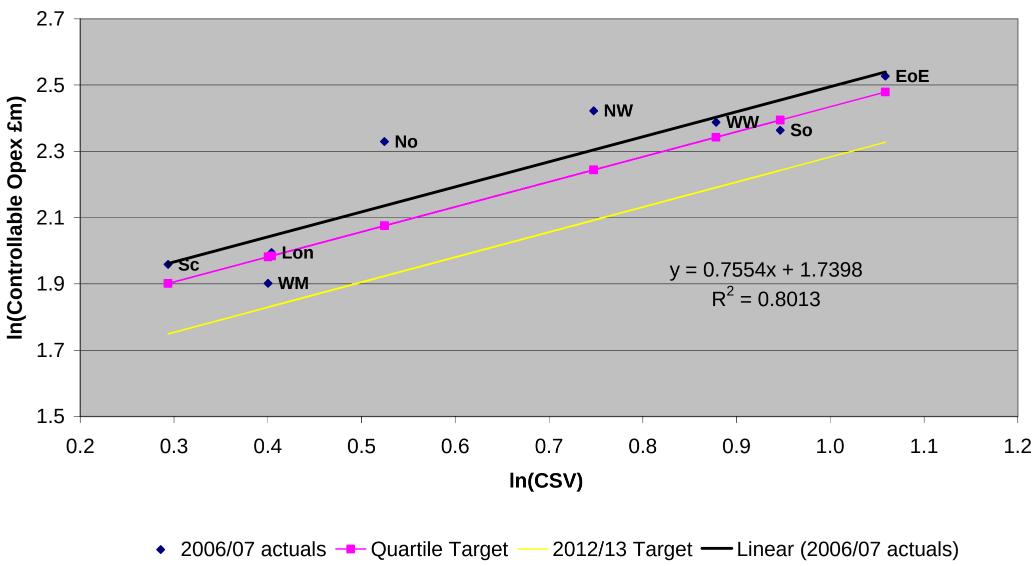


Maintenance

1.12. 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 LTS, storage and other maintenance costs separately. 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. PB Power then added 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.

1.13. 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 number 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.

Figure A7.4 - Revised maintenance regression using 2006-07 actuals



Other direct activities

1.14. When PB Power updated the regression analysis for other direct activities for 2006-07 actuals, it found that the quality of the regression had deteriorated since their initial proposals analysis based on forecasts of 2006-07 costs. Despite much effort to cleanse the data and to try various drivers, PB Power could not find robust enough regressions on which to base the analysis. Our allowances for other direct activities have therefore been based on GDN projections of their expenditure for 2008-09 to 2012-13 but adjusted for our own view of real price effects and ongoing efficiencies.

Indirect opex

1.15. In our initial proposals, we presented bottom-up allowances based on LECG's analysis. LECG used upper quartile benchmarks calculated from comparing the GDN company groups and external sources for certain functions. Since initial proposals, LECG have updated their analysis using 2006-07 outturn cost data submitted by the GDNs In addition, we have considered the arguments put forward by the GDNs and, as a result, we have made limited changes to the methodology for calculating indirect opex allowances.

1.16. The GDNs raised a number of issues in relation to the indirect cost analysis presented in initial proposals. In general, they felt the allowances set by the bottom-up analysis was too challenging. In particular, WWU commissioned consultants, Third Horizon, to illustrate the implications of the initial proposals, which they judged to be very onerous, particularly for WWU's Finance Audit and Regulation (FAR) and HR functions Third Horizon also highlighted the fact that a significant proportion of WWU's indirect functions were outsourced reducing the potential for cost reductions that WWU could be expected to achieve over the next price control period. The IDNs argued that NGG benefited from inherent economies of scale from its ownership of four GDNs. The IDNs pointed to the fact that, in initial proposals, NGG's indirect allowances were higher than the total of the IDNs' allowances. One GDN suggested that the external benchmarks were too severe given that the IDNs who had only recently created functions were being found inefficient against such benchmarks. One GDN was concerned that SGN's marginal cost allocation of indirect costs was resulting in unsustainable benchmarks where SGN set the frontier.

1.17. Table A7.2 below sets out the effects of using the 2006-07 outturn data and the changes to our methodology. The third section of the table shows indirect opex allowances calculated using 2006-07 outturn on the same basis as initial proposals. The most significant change is a reduction in NGG's costs, where costs that were included but not benchmarked, have been reclassified as direct opex which is consistent with the other GDNs. In addition NGG have reallocated IS costs from London to its other GDNs. The final section of the table sets out our updated proposals for indirect opex. These are based on the 2006-07 outturn and our revised methodology. The key changes are:

- removal of all external benchmarks for HR and Finance, Audit and Regulation. For HR we have used the ratio of HR FTEs to total FTEs which we believe captures the cost drivers better than the cost based metric previously used by LECG; and
- use of the "second best" GDN as the benchmark instead of the upper quartile for all functions. This is to minimise any distortions arising from SSE's use of a marginal cost methodology for the provision of some support services to SGN which is the frontier GDN company for most indirect functions.

Table A7.2 - Ofgem's updated proposals for indirect opex (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU		
GDN Normalised Indirect Opex 2008-09 to 2012-13	**East of England**	**London**	**North West**	**West Midlands**	**Northern**	**Scotland**	**Southern**	**Wales & West**	**Total GDN**	**Average annual GDN spend**
IS	50.1	23.2	35.1	26.3	38.8	21.5	32.3	41.2	268.5	6.7
Finance, Audit and Regulation	25.8	11.1	16.6	13.1	20.3	10.1	15.1	18.1	130.2	3.3
Insurance	35.7	18.0	24.8	17.5	16.4	11.7	17.5	17.6	159.2	4.0
Property management	27.2	23.9	31.6	25.7	13.5	7.4	11.1	20.7	161.1	4.0
Corporate Centre and Comms.	13.6	9.1	10.7	7.1	10.3	4.0	6.0	11.5	72.4	1.8
HR	28.3	13.9	20.6	14.1	5.6	4.7	7.1	5.5	99.8	2.5
Legal	2.8	2.2	2.7	2.8	5.8	2.1	3.1	3.5	25.0	0.6
Procurement and logistics	13.6	7.0	10.0	7.3	9.0	4.2	6.3	9.1	66.6	1.7
Total Indirect Opex	**197.1**	**108.5**	**152.1**	**113.8**	**119.7**	**65.7**	**98.7**	**127.3**	**982.9**	**24.6**
Ofgem Initial Proposals allowances										
IS	38.8	29.3	26.0	19.4	28.4	24.6	37.0	27.6	231.1	5.8
Finance, Audit and Regulation	23.7	12.8	15.4	11.7	9.1	8.0	11.9	10.0	102.7	2.6
Insurance	20.9	12.3	15.7	12.6	14.2	11.0	16.6	15.0	118.2	3.0
Property management	22.1	20.2	24.1	19.4	11.0	6.1	9.1	10.5	122.4	3.1
Corporate Centre and Comms.	8.8	5.5	6.7	4.6	7.0	6.1	9.2	7.3	55.2	1.4
HR	3.1	1.6	2.2	1.5	2.3	1.9	2.9	2.2	17.7	0.4
Legal	2.4	2.0	2.2	2.2	2.3	2.0	3.0	2.3	18.5	0.5
Procurement and logistics	9.3	4.3	5.9	3.9	6.4	5.6	8.4	6.8	50.7	1.3
Total Indirect Opex	**129.1**	**88.0**	**98.2**	**75.3**	**80.6**	**65.4**	**98.1**	**81.8**	**716.5**	**17.9**
Ofgem Initial Proposals rerun on 2006-07 actuals										
IS	36.0	16.7	25.3	18.9	29.5	24.9	37.4	28.7	217.5	5.4
Finance, Audit and Regulation	13.8	5.9	8.8	7.0	8.1	7.4	11.1	9.5	71.7	1.8
Insurance	22.1	11.1	15.3	10.8	13.8	11.7	17.5	15.1	117.5	2.9
Property management	20.9	18.4	24.4	19.8	12.7	8.8	13.3	9.7	128.1	3.2
Corporate Centre and Comms.	7.3	4.9	5.7	3.8	5.6	5.2	7.8	6.1	46.4	1.2
HR	2.9	1.4	2.1	1.4	2.0	1.8	2.7	2.2	16.4	0.4
Legal	1.9	1.5	1.8	1.9	1.8	1.7	2.5	2.0	15.0	0.4
Procurement and logistics	5.0	2.6	3.7	2.7	3.6	3.4	5.1	3.9	30.0	0.8
Total Indirect Opex	**109.9**	**62.6**	**87.2**	**66.3**	**77.1**	**64.9**	**97.4**	**77.2**	**642.6**	**16.1**
Ofgem Updated Proposals baseline										
IS	38.9	18.0	27.3	20.4	31.4	25.3	37.9	30.3	229.4	5.7
Finance, Audit and Regulation	18.0	7.7	11.5	9.2	11.9	9.5	14.3	13.0	95.2	2.4
Insurance	22.1	11.1	15.3	10.8	13.8	11.7	17.5	15.0	117.4	2.9
Property management	20.9	18.4	24.4	19.8	12.7	8.8	13.2	9.7	128.0	3.2
Corporate Centre and Comms.	8.8	5.9	6.9	4.6	6.7	5.2	7.8	7.3	53.2	1.3
HR	2.2	1.1	1.6	1.1	1.6	2.9	4.3	3.9	18.8	0.5
Legal	2.1	1.7	2.1	2.1	2.1	1.9	2.8	2.3	17.1	0.4
Procurement and logistics	5.6	2.9	4.1	3.0	3.9	3.4	5.1	4.4	32.4	0.8
Total Indirect Opex	**118.7**	**66.9**	**93.2**	**71.0**	**84.1**	**68.6**	**103.0**	**86.0**	**691.5**	**17.3**
Change from IP to UP	**-10.5**	**-21.1**	**-5.0**	**-4.3**	**3.5**	**3.2**	**5.0**	**4.2**	**-25.0**	**-0.6**

1.18. The updated proposals for indirect opex allowances are higher for the IDNs compared to the initial proposals. NGG's allowances have reduced for the reasons set out in paragraph 1.17.

IS

1.19. As with initial proposals, the impact of IS investment cycles have been taken into account by benchmarking the average IS spend over 2005-06 to 2012-13 as a percentage of revenue. LECG has updated their analysis for the 2006-07 outturn costs. We have benchmarked based on the second lowest cost GDN. The results are summarised below.

Table A7.3 - Summary of IS support costs benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Information Systems (% of revenue)	1.85%	1.85%	2.19%	1.50%	2.38%

Finance, audit and regulation

1.20. In initial proposals, finance and audit costs were benchmarked separately from regulation. In both cases they were compared to the upper quartile drawn from external data sources. Having considered the GDNs' responses we accept that the implied reductions may be too onerous so we have set the benchmark at the second lowest cost GDN group. LECG have updated their results for the 2006-07 outturn the results are summarised below.

Table A7.4 - Summary of finance, audit and regulation benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Finance & Audit (% of revenue)	0.85%	1.17%	0.85%	0.42%	1.19%
Regulation (% of total opex)	0.27%	0.20%	0.33%	0.27%	0.27%

Insurance

1.21. As in initial proposals, we compared the GDNs against each other in the base year but using the second lowest cost group to set the benchmark. The adjusted base year costs have been rolled forward using the market cycle approach proposed by Marsh in the 2006 transmission review.

1.22. In response to initial proposals, NGG argued that the market cycle should not be applied to premia and losses retained by its insurance captives. We believe that it is reasonable to expect captive premia to be competitive in relation to the market and therefore appropriate to apply the market cycle. The results of the insurance benchmarking updated for 2006-07 outturn costs is summarised below.

Table A7.5 - Summary of insurance benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Base Year Insurance (% of revenue)	1.04%	1.54%	1.12%	0.95%	1.04%
Insurance forecast years	Base year costs are forecast to follow the market cycle trend as				

Property Management

1.23. As with initial proposals, GDNs have been assessed against each other on the basis of levels of floor space (normalised for the size of GDN by looking at floor space per km of pipeline) and facilities management costs per square foot of property. Rental costs for individual properties have also been benchmarked against local market data, leading to further adjustments for some of the GDNs. LECG has updated their analysis for the 2006-07 outturn cost and floor space data. The results are summarised below.

Table A7.6 - Summary of property management benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Property (Sqft floorspace/km pipeline)	2.7	3.8	2.1	3.0	2.7
Property (FM costs/Sqft floorspace)	16.9	29.9	11.0	16.9	36.9

Corporate Centre and Communications

1.24. Corporate and communication costs have been compared as a percentage of total operating costs. LECG have updated their results for the 2006-07 outturn data and the benchmark is now set at the second lowest GDN. The results are summarised below.

Table A7.7 - Summary of corporate centre and communications benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Corporate Centre & Comms (% of total opex)	0.96%	1.50%	0.96%	0.34%	1.12%

Human Resources

1.25. In initial proposals, LECG used external comparators to set the benchmark HR costs as a percentage of revenue. The GDNs argued that the implied cost reductions were unsustainable and that a FTE based benchmark would be more cost reflective. Having considered the GDNs responses, we have benchmarked the GDNs on their ratio of HR FTEs to total FTEs calculated from data previously provided by the GDNs to LECG. Training and apprentice costs have been assessed separately and therefore have been excluded from HR costs before applying the benchmark results which are summarised below.

Table A7.8 - Summary of HR benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Human Resources (HR FTEs % of total FTEs)	0.48%	1.32%	0.75%	0.46%	0.48%

Legal

1.26. Legal costs have been compared as a percentage of revenue LECG have updated their results for the 2006-07 outturn data and we have now applied a benchmark based on the second lowest GDN. The results are summarised below.

Table A7.9 - Summary of legal costs benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Legal (% revenue)	0.18%	0.18%	0.27%	0.17%	0.22%

Procurement and Logistics

1.27. Procurement and logistics costs have been compared as a percentage of total opex. LECG has updated their results for the 2006-07 outturn data and the benchmark is now set at the second lowest GDN. The results are summarised below.

Table A7.10 - Summary of procurement and logistics benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Procurement & Logistics (% of total opex)	0.57%	0.87%	0.57%	0.42%	1.09%

Appendix 8 - Opex tables

National Grid Gas - East of England, Ofgem proposed opex

Table A8.1 - Direct opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Work Management	22.4	22.1	21.7	21.4	21.2	108.8	126.9
Emergency	11.2	11.0	10.8	10.7	10.5	54.1	55.2
Repair	9.3	9.1	8.9	8.7	8.5	44.5	42.3
Maintenance	14.8	13.5	12.7	12.3	12.5	65.8	62.4
Other Direct Activities	2.3	2.3	2.2	2.2	2.2	11.2	11.9
Xoserve	4.2	4.1	4.1	4.1	4.1	20.7	23.8
LNG to SIUs						0.0	0.0
Total Direct Opex	**64.3**	**62.1**	**60.5**	**59.4**	**59.0**	**305.2**	**322.6**

Table A8.2 - Indirect opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
IS	9.3	8.9	7.5	6.5	6.5	38.9	38.8
Finance, Audit and Regulation	3.7	3.7	3.6	3.5	3.5	18.0	23.7
Insurance	3.2	3.9	4.6	5.3	5.2	22.1	20.9
Property Management	4.4	4.3	4.2	4.1	4.0	20.9	22.1
Corporate Centre and Comms	1.8	1.8	1.8	1.7	1.7	8.8	8.8
HR	0.5	0.5	0.4	0.4	0.4	2.2	3.1
Legal	0.4	0.4	0.4	0.4	0.4	2.1	2.4
Procurement and Logistics	1.2	1.1	1.1	1.1	1.1	5.6	9.3
Total Indirect Opex	**24.5**	**24.6**	**23.7**	**23.1**	**22.7**	**118.7**	**129.1**

Table A8.3 - Total opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Direct Cost	64.3	62.1	60.5	59.4	59.0	305.2	322.7
Indirect Costs	24.5	24.6	23.7	23.1	22.7	118.7	129.1
Adjustment to top down	5.5	5.4	5.2	5.1	5.1	26.4	25.4
Quality of Service	0.4	0.4	0.4	0.4	0.4	1.9	1.3
SIU costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Training and apprentice allowance	2.1	2.1	2.1	2.1	2.1	10.7	0.0
Environmental remediation	1.0	1.1	1.4	0.6	0.6	4.7	0.0
Waste management costs	0.2	0.3	0.4	0.5	0.6	1.9	0.0
Non-labour regional factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Opex	**98.0**	**96.0**	**93.7**	**91.2**	**90.5**	**469.4**	**478.5**

National Grid Gas - London, Ofgem proposed opex

Table A8.4 - Direct opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Work Management	16.9	16.7	16.5	16.2	16.0	82.3	81.7
Emergency	9.2	9.1	9.0	8.9	8.7	44.9	43.5
Repair	10.2	10.0	9.8	9.6	9.4	48.9	42.8
Maintenanace	12.2	9.6	9.3	9.4	9.2	49.7	42.4
Other Direct Activities	1.4	1.3	1.3	1.3	1.3	6.6	4.5
Xoserve	2.4	2.4	2.4	2.4	2.4	12.1	11.8
LNG to SIUs							0.0
Total Direct Opex	**52.4**	**49.2**	**48.3**	**47.8**	**47.0**	**244.6**	**226.9**

Table A8.5 - Indirect opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
IS	4.3	4.1	3.5	3.0	3.0	18.0	29.3
Finance, Audit and Regulation	1.6	1.6	1.5	1.5	1.5	7.7	12.8
Insurance	1.6	2.0	2.3	2.7	2.6	11.1	12.3
Property Management	3.9	3.8	3.7	3.6	3.5	18.4	20.2
Corporate Centre and Comms	1.2	1.2	1.2	1.2	1.1	5.9	5.5
HR	0.2	0.2	0.2	0.2	0.2	1.1	1.6
Legal	0.4	0.3	0.3	0.3	0.3	1.7	2.0
Procurement and Logistics	0.6	0.6	0.6	0.6	0.6	2.9	4.3
Total Indirect Opex	**13.8**	**13.8**	**13.4**	**13.1**	**12.8**	**66.9**	**88.0**

Table A8.6 - Total opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Direct Cost	52.4	49.2	48.3	47.8	47.0	244.6	226.8
Indirect Costs	13.8	13.8	13.4	13.1	12.8	66.9	88.0
Adjustment to top down	4.1	3.9	3.8	3.8	3.7	19.4	17.7
Quality of Service	0.7	0.6	0.6	0.6	0.6	3.2	2.6
SIU costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Training and apprentice allowance	1.2	1.2	1.2	1.2	1.2	6.2	0.0
Environmental remediation	1.0	1.1	1.4	0.6	0.6	4.7	0.0
Waste management costs	0.1	0.2	0.3	0.4	0.5	1.5	0.0
Non-labour regional factors	1.9	1.9	1.9	1.9	1.9	9.6	0.0
Total Opex	**75.2**	**72.0**	**70.9**	**69.4**	**68.4**	**356.0**	**335.1**

National Grid Gas - North West, Ofgem proposed opex

Table A8.7 - Direct opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Work Management	18.3	18.0	17.8	17.5	17.3	88.8	97.5
Emergency	9.1	9.0	8.9	8.8	8.6	44.4	44.6
Repair	9.5	9.3	9.1	8.9	8.7	45.5	40.4
Maintenanace	11.0	10.8	10.6	10.4	11.4	54.1	45.4
Other Direct Activities	1.3	1.2	1.1	1.1	1.1	5.9	7.6
Xoserve	2.9	2.9	2.9	2.9	2.9	14.6	15.6
LNG to SIUs						0.0	0.0
Total Direct Opex	**52.1**	**51.3**	**50.4**	**49.5**	**50.0**	**253.3**	**251.1**

Table A8.8 - Indirect opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
IS	6.6	6.3	5.3	4.6	4.6	27.3	26.0
Finance, Audit and Regulation	2.4	2.4	2.3	2.3	2.2	11.5	15.4
Insurance	2.2	2.7	3.2	3.7	3.6	15.3	15.7
Property Management	5.1	5.0	4.9	4.8	4.6	24.4	24.1
Corporate Centre and Comms	1.4	1.4	1.4	1.3	1.3	6.9	6.7
HR	0.3	0.3	0.3	0.3	0.3	1.6	2.2
Legal	0.4	0.4	0.4	0.4	0.4	2.1	2.2
Procurement and Logistics	0.9	0.8	0.8	0.8	0.8	4.1	5.9
Total Indirect Opex	**19.3**	**19.3**	**18.6**	**18.1**	**17.8**	**93.2**	**98.2**

Table A8.9 - Total opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Direct Cost	52.1	51.3	50.4	49.5	50.0	253.3	251.1
Indirect Costs	19.3	19.3	18.6	18.1	17.8	93.2	98.2
Adjustment to top down	4.4	4.4	4.3	4.2	4.2	21.6	19.6
Quality of Service	0.2	0.2	0.2	0.2	0.2	1.2	1.1
SIU costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Training and apprentice allowance	1.6	1.6	1.6	1.6	1.6	7.9	0.0
Environmental remediation	1.0	1.1	1.4	0.6	0.6	4.7	0.0
Waste management costs	0.2	0.2	0.3	0.4	0.5	1.6	0.0
Non-labour regional factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Opex	**78.8**	**78.1**	**76.8**	**74.7**	**74.9**	**383.5**	**370.0**

National Grid Gas - West Midlands, Ofgem proposed opex

Table A8.10 - Direct opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Work Management	13.3	13.1	12.9	12.7	12.6	64.5	67.9
Emergency	5.9	5.8	5.8	5.7	5.6	28.8	23.6
Repair	7.1	6.9	6.8	6.7	6.5	34.0	28.9
Maintenanace	8.0	16.9	7.5	7.2	7.0	46.6	41.2
Other Direct Activities	1.1	1.0	1.0	1.0	1.0	5.1	5.2
Xoserve	2.4	2.4	2.4	2.4	2.4	12.2	13.1
LNG to SIUs						0.0	0.0
Total Direct Opex	**37.8**	**46.2**	**36.3**	**35.7**	**35.1**	**191.2**	**179.8**

Table A8.11 - Indirect opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
IS	4.9	4.7	4.0	3.4	3.4	20.4	19.4
Finance, Audit and Regulation	1.9	1.9	1.8	1.8	1.8	9.2	11.7
Insurance	1.5	1.9	2.3	2.6	2.5	10.8	12.6
Property Management	4.2	4.1	4.0	3.9	3.8	19.8	19.4
Corporate Centre and Comms	0.9	0.9	0.9	0.9	0.9	4.6	4.6
HR	0.2	0.2	0.2	0.2	0.2	1.1	1.5
Legal	0.4	0.4	0.4	0.4	0.4	2.1	2.2
Procurement and Logistics	0.6	0.6	0.6	0.6	0.6	3.0	3.9
Total Indirect Opex	**14.8**	**14.7**	**14.2**	**13.8**	**13.6**	**71.0**	**75.3**

Table A8.12 - Total opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Direct Cost	37.8	46.2	36.3	35.7	35.1	191.2	179.8
Indirect Costs	14.8	14.7	14.2	13.8	13.6	71.0	75.3
Adjustment to top down	3.3	3.8	3.1	3.1	3.0	16.3	14.3
Quality of Service	0.2	0.2	0.1	0.1	0.1	0.8	0.5
SIU costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Training and apprentice allowance	1.1	1.1	1.1	1.1	1.1	5.3	0.0
Environmental remediation	1.0	1.1	1.4	0.6	0.6	4.7	0.0
Waste management costs	0.1	0.2	0.2	0.3	0.3	1.1	0.0
Non-labour regional factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Opex	**58.2**	**67.2**	**56.5**	**54.6**	**53.8**	**290.3**	**269.9**

Northern Grid Networks - Northern, Ofgem proposed opex

Table A8.13 - Direct opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Work Management	19.0	18.8	18.5	18.2	18.0	92.6	99.7
Emergency	8.7	8.6	8.4	8.3	8.2	42.2	41.6
Repair	10.6	10.3	10.1	9.9	9.6	50.4	41.8
Maintenanace	9.5	9.3	9.2	9.4	9.4	46.8	58.3
Other Direct Activities	1.9	1.9	1.8	1.8	1.7	9.0	8.0
Xoserve	2.7	2.8	2.7	2.7	2.8	13.6	14.6
LNG to SIUs						0.0	0.0
Total Direct Opex	**52.3**	**51.6**	**50.8**	**50.3**	**49.7**	**254.7**	**264.0**

Table A8.14 - Indirect opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
IS	5.3	6.7	6.6	6.4	6.4	31.4	28.4
Finance, Audit and Regulation	2.5	2.4	2.4	2.3	2.3	11.9	9.1
Insurance	1.9	2.4	2.9	3.3	3.3	13.8	14.2
Property Management	2.7	2.6	2.5	2.5	2.4	12.7	11.0
Corporate Centre and Comms	1.4	1.4	1.3	1.3	1.3	6.7	7.0
HR	0.3	0.3	0.3	0.3	0.3	1.6	2.3
Legal	0.4	0.4	0.4	0.4	0.4	2.1	2.3
Procurement and Logistics	0.8	0.8	0.8	0.8	0.8	3.9	6.4
Total Indirect Opex	**15.3**	**17.0**	**17.3**	**17.4**	**17.1**	**84.1**	**80.6**

Table A8.15 - Total opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Direct Cost	52.3	51.6	50.8	50.3	49.7	254.7	264.0
Indirect Costs	15.3	17.0	17.3	17.4	17.1	84.1	80.6
Adjustment to top down	4.2	4.3	4.2	4.2	4.2	21.1	19.4
Quality of Service	0.3	0.3	0.3	0.3	0.3	1.6	0.8
SIU costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Training and apprentice allowance	1.6	1.6	1.6	1.6	1.6	7.9	0.0
Environmental remediation	1.0	1.0	1.0	1.0	1.0	5.0	0.0
Waste management costs	0.1	0.2	0.2	0.3	0.4	1.2	0.0
Non-labour regional factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Opex	**74.9**	**76.0**	**75.4**	**75.1**	**74.2**	**375.6**	**364.8**

Scotia Gas Networks - Scotland, Ofgem proposed opex

Table A8.16 - Direct opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Work Management	13.6	13.4	13.3	13.0	12.9	66.2	72.5
Emergency	6.7	6.6	6.5	6.4	6.3	32.6	31.0
Repair	7.3	7.1	7.0	6.8	6.7	35.0	32.3
Maintenanace	8.2	7.5	8.0	7.5	7.1	38.3	29.4
Other Direct Activities	1.0	1.0	1.0	0.9	0.9	4.8	5.0
Xoserve	1.8	1.9	1.9	1.9	1.8	9.1	9.7
LNG to SIUs	4.8	4.8	4.8	4.8	4.8	24.0	24.0
Total Direct Opex	**43.4**	**42.4**	**42.4**	**41.3**	**40.5**	**210.0**	**203.9**

Table A8.17 - Indirect opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
IS	5.3	5.2	5.0	4.9	4.8	25.3	24.6
Finance, Audit and Regulation	2.0	1.9	1.9	1.9	1.8	9.5	8.0
Insurance	1.6	2.0	2.4	2.8	2.8	11.7	11.0
Property Management	1.9	1.8	1.8	1.7	1.7	8.8	6.1
Corporate Centre and Comms	1.1	1.1	1.0	1.0	1.0	5.2	6.1
HR	0.6	0.6	0.6	0.6	0.6	2.9	1.9
Legal	0.4	0.4	0.4	0.4	0.4	1.9	2.0
Procurement and Logistics	0.7	0.7	0.7	0.7	0.6	3.4	5.6
Total Indirect Opex	**13.6**	**13.7**	**13.8**	**13.9**	**13.6**	**68.6**	**65.4**

Table A8.18 - Total opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Direct Cost	43.4	42.4	42.4	41.3	40.5	210.0	203.9
Indirect Costs	13.6	13.7	13.8	13.9	13.6	68.6	65.4
Adjustment to top down	3.5	3.5	3.5	3.4	3.4	17.3	15.1
Quality of Service	0.2	0.2	0.2	0.2	0.2	1.0	0.7
SIU costs	1.2	0.6	0.6	0.6	0.6	3.6	0.0
Training and apprentice allowance	1.7	1.7	1.7	1.7	1.7	8.7	0.0
Environmental remediation	0.5	0.5	0.5	0.5	0.5	2.5	0.0
Waste management costs	0.1	0.2	0.2	0.3	0.4	1.1	0.0
Non-labour regional factors	1.0	1.0	1.0	1.0	1.0	5.0	0.0
Total Opex	**65.3**	**63.7**	**64.0**	**63.0**	**61.8**	**317.9**	**285.1**

Scotia Gas Networks - Southern, Ofgem proposed opex

Table A8.19 - Direct opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Work Management	28.8	28.4	28.0	27.6	27.2	140.0	155.9
Emergency	15.4	15.1	14.9	14.7	14.4	74.5	82.9
Repair	19.8	19.3	18.9	18.4	18.0	94.5	83.2
Maintenance	14.6	13.4	12.5	12.0	12.0	64.4	44.2
Other Direct Activities	2.8	2.7	2.6	2.5	2.4	13.1	11.3
Xoserve	4.1	4.1	4.1	4.1	4.1	20.6	22.0
LNG to SIUs							0.0
Total Direct Opex	**85.6**	**83.0**	**81.0**	**79.3**	**78.2**	**407.1**	**399.6**

Table A8.20 - Indirect opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
IS	8.0	7.8	7.6	7.4	7.2	37.9	37.0
Finance, Audit and Regulation	3.0	2.9	2.9	2.8	2.7	14.3	11.9
Insurance	2.4	3.1	3.7	4.2	4.1	17.5	16.6
Property Management	2.8	2.7	2.6	2.6	2.5	13.2	9.1
Corporate Centre and Comms	1.6	1.6	1.6	1.5	1.5	7.8	9.2
HR	0.9	0.9	0.9	0.8	0.8	4.3	2.9
Legal	0.6	0.6	0.6	0.6	0.5	2.8	3.0
Procurement and Logistics	1.1	1.0	1.0	1.0	1.0	5.1	8.4
Total Indirect Opex	**20.4**	**20.6**	**20.8**	**20.9**	**20.4**	**103.0**	**98.1**

Table A8.21 - Total opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Direct Cost	85.6	83.0	81.0	79.3	78.2	407.1	399.6
Indirect Costs	20.4	20.6	20.8	20.9	20.4	103.0	98.1
Adjustment to top down	6.6	6.4	6.3	6.2	6.1	31.7	28.0
Quality of Service	0.4	0.4	0.4	0.4	0.4	1.9	1.6
SIU costs	0.7	0.0	0.0	0.0	0.0	0.7	0.0
Training and apprentice allowance	2.5	2.5	2.5	2.5	2.5	12.6	0.0
Environmental remediation	0.5	0.5	0.5	0.5	0.5	2.5	0.0
Waste management costs	0.2	0.4	0.5	0.6	0.8	2.5	0.0
Non-labour regional factors	1.2	1.2	1.2	1.2	1.2	6.0	0.0
Total Opex	**118.0**	**115.0**	**113.2**	**111.7**	**110.1**	**567.9**	**527.3**

Wales & West Utilities - Wales & West, Ofgem proposed opex

Table A8.22 - Direct opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Work Management	16.7	16.5	16.2	16.0	15.8	81.1	97.3
Emergency	7.1	7.0	6.9	6.8	6.7	34.6	36.5
Repair	9.2	9.0	8.8	8.6	8.4	44.0	40.0
Maintenanace	12.7	13.0	11.1	10.4	10.3	57.4	62.5
Other Direct Activities	2.2	2.2	2.2	2.1	2.1	10.8	7.6
Xoserve	2.6	2.6	2.6	2.6	2.6	13.1	14.0
LNG to SIUs						0.0	0.0
Total Direct Opex	**50.6**	**50.2**	**47.8**	**46.4**	**45.9**	**240.9**	**257.8**

Table A8.23 - Indirect opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
IS	6.5	6.5	6.5	5.9	5.0	30.3	27.6
Finance, Audit and Regulation	2.7	2.7	2.6	2.6	2.5	13.0	10.0
Insurance	2.1	2.6	3.1	3.6	3.6	15.0	15.0
Property Management	2.0	2.0	1.9	1.9	1.8	9.7	10.5
Corporate Centre and Comms	1.5	1.5	1.5	1.4	1.4	7.3	7.3
HR	0.8	0.8	0.8	0.8	0.8	3.9	2.2
Legal	0.5	0.5	0.5	0.5	0.4	2.3	2.3
Procurement and Logistics	0.9	0.9	0.9	0.9	0.8	4.4	6.8
Total Indirect Opex	**17.0**	**17.4**	**17.7**	**17.5**	**16.4**	**86.0**	**81.8**

Table A8.24 - Total opex, (£m, 2005-06 prices)

Ofgem Updated Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Direct Cost	50.6	50.2	47.8	46.4	45.9	240.9	257.9
Indirect Costs	17.0	17.4	17.7	17.5	16.4	86.0	81.8
Adjustment to top down	4.2	4.2	4.1	4.0	3.9	20.3	19.1
Quality of Service	0.2	0.2	0.2	0.2	0.2	0.9	0.6
SIU costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Training and apprentice allowance	1.7	1.7	1.7	1.7	1.7	8.7	0.0
Environmental remediation	2.3	2.3	2.3	2.3	2.3	11.5	0.0
Waste management costs	0.1	0.2	0.2	0.3	0.3	1.0	0.0
Non-labour regional factors	2.0	2.0	2.0	2.0	2.0	10.0	0.0
Total Opex	**78.1**	**78.2**	**76.0**	**74.4**	**72.6**	**379.4**	**359.4**

Appendix 9 - Capex and repex tables & treatment of historical expenditure

National Grid Gas - East of England, Ofgem proposed capex and repex

Table A9.1 - Net capex, (£m, 2005-06 prices)

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
LTS & Storage	8.4	8.9	7.8	16.0	10.6	51.7	53.3
Connections	9.2	9.7	10.1	10.3	10.7	50.0	47.5
Mains Reinforcement	4.4	2.5	3.1	2.8	2.9	15.7	14.2
Governors	0.5	0.7	0.5	0.5	0.8	3.1	2.9
Other Operational	1.5	1.4	1.4	1.4	1.4	7.2	9.3
Non Operational	14.6	11.4	17.2	24.8	19.2	87.2	82.3
Total Net Capex	**38.7**	**34.6**	**40.2**	**55.8**	**45.6**	**214.9**	**209.4**
Ofgem Proposed Allowances							
LTS & Storage	6.9	7.2	7.4	3.9	13.8	39.2	46.1
Connections	6.8	6.8	6.8	6.8	6.8	34.1	33.2
Mains Reinforcement	3.4	2.1	2.4	2.1	2.1	12.1	15.4
Governors	0.5	0.7	0.5	0.5	0.8	3.0	2.9
Other Operational	1.5	1.4	1.4	1.4	1.4	7.1	8.0
Non Operational	14.9	11.4	16.8	24.4	19.2	86.8	82.1
Total Net Capex	**34.1**	**29.6**	**35.3**	**39.1**	**44.1**	**182.3**	**187.7**

Table A9.2 - Net repex, (£m, 2005-06 prices)

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	58.6	67.5	69.7	75.0	77.5	348.3	338.9
Services (excl. Riser costs)	32.7	36.6	37.2	36.6	38.0	181.1	175.0
LTS	0.2	0.2	0.2	0.2	0.2	0.8	0.0
Total Net Repex	**91.5**	**104.3**	**107.0**	**111.7**	**115.7**	**530.2**	**513.9**
Ofgem Proposed Allowances							
Mains	62.4	68.4	69.0	73.6	74.1	347.5	332.0
Services (excl. Riser costs)	27.8	29.7	29.5	28.2	28.3	143.5	138.3
LTS	0.2	0.2	0.1	0.1	0.1	0.7	0.0
Total Net Repex	**90.3**	**98.3**	**98.7**	**101.9**	**102.6**	**491.7**	**470.2**

Table A9.3 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	2.1	2.4	2.6	2.7	2.9	**12.7**	**3.9**
Ofgem proposed allowances							
UP proposed allowances	1.5	1.7	1.8	1.9	2.1	**9.0**	**3.9**

National Grid Gas - London, Ofgem proposed capex and repex

Table A9.4 - Net capex, (£m, 2005-06 prices)

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
LTS & Storage	44.1	41.2	9.3	23.6	18.8	136.9	84.3
Connections	4.9	4.8	5.7	5.8	6.0	27.2	30.3
Mains Reinforcement	2.4	2.3	1.5	3.3	3.5	13.0	11.1
Governors	2.2	2.2	2.4	2.4	0.6	10.0	9.7
Other Operational	1.2	1.0	1.3	1.1	1.2	5.7	7.9
Non Operational	8.4	6.9	9.3	13.1	9.9	47.7	51.8
Total Net Capex	**63.2**	**58.4**	**29.5**	**49.4**	**40.0**	**240.5**	**195.1**
Ofgem Proposed Allowances							
LTS & Storage	41.8	37.0	7.6	8.2	20.8	115.4	63.9
Connections	4.4	4.4	4.4	4.4	4.4	22.0	22.6
Mains Reinforcement	1.2	1.2	0.9	1.8	1.8	6.9	8.2
Governors	2.1	2.2	2.3	2.3	0.6	9.5	9.3
Other Operational	1.1	0.9	1.2	1.0	1.1	5.4	7.2
Non Operational	8.6	6.9	9.3	13.1	9.9	47.8	51.7
Total Net Capex	**59.2**	**52.6**	**25.7**	**30.9**	**38.6**	**207.0**	**162.9**

Table A9.5 - Net repex, (£m, 2005-06 prices)

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	71.5	63.7	68.3	70.5	68.1	342.2	332.1
Services (excl. Riser costs)	27.2	24.6	26.3	28.6	28.7	135.4	132.3
LTS	0.1	0.1	0.1	0.2	0.2	0.6	0.2
Total Net Repex	**98.9**	**88.4**	**94.6**	**99.3**	**97.0**	**478.2**	**464.6**
Ofgem Proposed Allowances							
Mains	72.0	62.8	64.5	64.0	60.1	323.5	278.7
Services (excl. Riser costs)	21.3	18.9	19.6	21.0	20.3	101.2	93.6
LTS	0.1	0.1	0.1	0.2	0.2	0.6	0.2
Total Net Repex	**93.4**	**81.8**	**84.2**	**85.2**	**80.6**	**425.2**	**372.4**

Table A9.6 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	7.0	7.6	8.5	9.5	9.6	**42.2**	**14.5**
Ofgem proposed allowances							
UP proposed allowances	5.0	5.4	6.0	6.7	6.8	**29.9**	**14.5**

National Grid Gas - North West, Ofgem proposed capex and repex

Table A9.7 - Net capex, (£m, 2005-06 prices)

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
LTS & Storage	6.6	13.1	17.4	28.3	9.9	75.3	57.7
Connections	3.8	4.2	4.4	4.8	4.8	22.0	21.7
Mains Reinforcement	0.8	2.8	2.9	2.2	4.4	13.2	12.8
Governors	2.8	2.7	3.7	3.1	3.9	16.3	15.7
Other Operational	1.2	1.1	1.2	1.2	1.2	5.9	7.8
Non Operational	9.7	8.2	12.5	16.5	13.2	60.0	60.2
Total Net Capex	**24.9**	**32.2**	**42.1**	**56.1**	**37.4**	**192.7**	**175.8**
Ofgem Proposed Allowances							
LTS & Storage	6.1	6.9	6.4	4.3	4.1	27.8	52.3
Connections	3.8	3.8	3.8	3.8	3.8	18.9	14.4
Mains Reinforcement	0.7	2.0	2.1	1.5	1.8	8.0	10.8
Governors	2.8	2.7	3.6	3.0	3.8	16.0	15.6
Other Operational	1.2	1.1	1.2	1.2	1.2	5.8	7.3
Non Operational	10.0	8.2	12.3	16.2	13.2	59.9	60.0
Total Net Capex	**24.5**	**24.7**	**29.3**	**30.0**	**27.8**	**136.3**	**160.5**

Table A9.8 - Net repex, (£m, 2005-06 prices)

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	71.5	72.2	71.6	73.8	70.8	359.8	351.6
Services (excl. Riser costs)	31.0	31.2	30.7	31.0	30.1	154.0	145.1
LTS	0.1	0.1	0.1	0.1	0.1	0.3	0.0
Total Net Repex	**102.6**	**103.5**	**102.4**	**104.8**	**100.9**	**514.1**	**496.6**
Ofgem Proposed Allowances							
Mains	67.5	66.6	65.2	65.5	61.4	326.2	304.9
Services (excl. Riser costs)	24.5	24.1	23.7	23.6	22.6	118.5	116.1
LTS	0.1	0.1	0.1	0.1	0.1	0.3	0.0
Total Net Repex	**92.0**	**90.8**	**89.0**	**89.1**	**84.0**	**445.0**	**420.9**

Table A9.9 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	1.9	2.0	2.2	2.4	2.5	**11.0**	**4.3**
Ofgem proposed allowances							
UP proposed allowances	1.3	1.4	1.6	1.7	1.8	**7.8**	**4.3**

National Grid Gas - West Midlands, Ofgem proposed capex and repex

Table A9.10 - Net capex, (£m, 2005-06 prices)

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
LTS & Storage	2.6	2.2	2.1	1.7	1.7	10.3	9.7
Connections	3.3	3.5	3.6	3.7	3.7	17.8	17.5
Mains Reinforcement	2.0	2.1	2.6	2.8	2.3	11.8	11.4
Governors	1.1	0.2	0.2	0.6	1.2	3.3	3.1
Other Operational	1.0	1.2	1.2	1.2	1.2	5.8	7.1
Non Operational	8.2	5.7	8.6	11.6	9.1	43.0	43.1
Total Net Capex	**18.1**	**14.9**	**18.3**	**21.5**	**19.2**	**92.0**	**92.0**
Ofgem Proposed Allowances							
LTS & Storage	2.0	2.2	2.1	1.7	1.7	9.5	9.5
Connections	3.1	3.1	3.1	3.1	3.2	15.7	13.7
Mains Reinforcement	1.6	1.8	1.6	2.0	1.6	8.6	11.6
Governors	1.1	0.2	0.2	0.6	1.2	3.3	3.1
Other Operational	1.0	1.2	1.2	1.2	1.2	5.7	6.7
Non Operational	8.4	5.7	8.4	11.4	9.1	42.9	42.9
Total Net Capex	**17.2**	**14.2**	**16.5**	**20.0**	**17.8**	**85.7**	**87.5**

Table A9.11 - Net repex, (£m, 2005-06 prices)

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	50.6	49.3	48.5	49.7	48.3	246.4	234.5
Services (excl. Riser costs)	22.7	23.3	23.5	23.0	23.7	116.1	107.5
LTS	0.0	0.0	0.0	0.0	0.0	0.2	0.0
Total Net Repex	**73.4**	**72.6**	**72.0**	**72.8**	**72.0**	**362.7**	**342.0**
Ofgem Proposed Allowances							
Mains	53.6	50.5	47.7	47.9	45.1	244.8	223.7
Services (excl. Riser costs)	18.3	18.4	18.1	17.3	17.6	89.7	88.0
LTS	0.0	0.0	0.0	0.0	0.0	0.2	0.2
Total Net Repex	**71.9**	**68.9**	**65.8**	**65.3**	**62.7**	**334.7**	**311.9**

Table A9.12 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	1.3	1.4	1.6	1.7	1.8	**7.8**	**2.7**
Ofgem proposed allowances							
UP proposed allowances	0.9	1.0	1.1	1.2	1.3	**5.5**	**2.7**

Northern Gas Networks - Northern, Ofgem proposed capex and repex

Table A9.13 - Net capex, (£m, 2005-06 prices)

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
LTS & Storage	4.2	9.0	3.1	29.7	30.5	76.5	75.2
Connections	8.9	8.9	9.3	9.2	9.6	45.9	47.0
Mains Reinforcement	4.8	4.9	5.0	5.0	5.1	24.9	24.7
Governors	1.5	1.7	1.8	1.9	1.8	8.8	8.9
Other Operational	7.6	5.4	4.9	4.9	4.4	27.3	26.3
Non Operational	26.6	17.7	10.3	14.2	9.2	77.9	78.3
Total Net Capex	**53.6**	**47.6**	**34.5**	**65.0**	**60.5**	**261.3**	**260.3**
Ofgem Proposed Allowances							
LTS & Storage	4.0	8.5	3.0	27.6	19.7	62.9	53.2
Connections	6.1	6.3	6.4	6.5	6.7	32.0	38.6
Mains Reinforcement	3.0	3.0	3.0	3.0	3.0	14.9	21.2
Governors	1.5	1.6	1.7	1.8	1.7	8.3	8.6
Other Operational	6.6	4.4	3.8	3.7	3.1	21.6	25.3
Non Operational	21.2	14.9	10.6	14.9	9.1	70.7	71.5
Total Net Capex	**42.5**	**38.7**	**28.4**	**57.6**	**43.3**	**210.4**	**218.4**

Table A9.14 - Net repex, (£m, 2005-06 prices)

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	46.6	49.2	51.7	53.1	54.6	255.2	253.4
Services (excl. Riser costs)	23.6	24.1	24.4	25.0	25.3	122.4	121.6
LTS	6.3	27.7	1.4	0.9	0.9	37.2	37.1
Total Net Repex	**76.6**	**101.0**	**77.6**	**79.0**	**80.8**	**414.9**	**412.2**
Ofgem Proposed Allowances							
Mains	43.2	44.8	45.6	45.6	46.0	225.2	229.2
Services (excl. Riser costs)	24.2	24.0	23.8	23.7	23.5	119.2	118.5
LTS	6.1	26.4	1.3	0.8	0.8	35.5	35.7
Total Net Repex	**73.5**	**95.2**	**70.8**	**70.1**	**70.3**	**379.9**	**383.3**

Table A9.15 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	0.7	0.7	0.7	2.4	2.4	**6.7**	**6.7**
Ofgem proposed allowances							
UP proposed allowances	0.7	0.7	0.7	1.7	1.7	**5.3**	**6.7**

Scotia Gas Networks - Scotland, Ofgem proposed capex and repex

Table A9.16 - Net capex, (£m, 2005-06 prices)

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
LTS & Storage	20.9	10.3	18.4	7.7	18.5	75.7	78.4
Connections	5.6	5.5	5.4	5.3	5.3	27.1	52.8
Mains Reinforcement	7.7	7.2	6.4	5.9	7.2	34.4	38.3
Governors	3.8	3.6	3.3	3.2	3.2	17.0	19.0
Other Operational	5.4	5.5	4.3	3.9	3.6	22.7	26.5
Non Operational	16.0	7.9	7.8	3.6	9.1	44.5	35.9
Total Net Capex	**59.3**	**40.0**	**45.7**	**29.6**	**46.8**	**221.4**	**250.8**
Ofgem Proposed Allowances							
LTS & Storage	17.8	7.6	16.6	5.8	7.0	54.7	60.9
Connections	4.8	4.8	4.7	4.7	4.7	23.7	40.7
Mains Reinforcement	5.3	5.1	4.5	4.4	4.8	23.9	30.5
Governors	3.6	3.4	3.1	2.9	2.8	15.8	17.0
Other Operational	5.1	5.1	3.9	3.5	3.1	20.7	20.7
Non Operational	15.5	7.9	3.9	4.2	9.1	40.7	36.6
Total Net Capex	**52.0**	**33.8**	**36.8**	**25.4**	**31.5**	**179.5**	**206.4**

Table A9.17 - Net repex, (£m, 2005-06 prices)

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	36.0	37.8	37.3	38.0	39.7	188.7	219.4
Services (excl. Riser costs)	18.9	19.0	19.1	19.2	19.3	95.5	118.3
LTS	0.3	0.0	0.0	0.0	0.0	0.3	0.3
Total Net Repex	**55.2**	**56.7**	**56.4**	**57.2**	**59.0**	**284.5**	**338.1**
Ofgem Proposed Allowances							
Mains	31.8	32.7	32.0	32.0	32.9	161.5	152.7
Services (excl. Riser costs)	16.2	16.2	16.2	16.2	16.2	80.9	73.2
LTS	0.3	0.0	0.0	0.0	0.0	0.3	0.3
Total Net Repex	**48.3**	**48.9**	**48.2**	**48.2**	**49.1**	**242.7**	**226.2**

Table A9.18 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	0.8	1.0	1.3	1.6	1.9	6.6	**18.6**
Ofgem proposed allowances							
UP proposed allowances	0.5	0.7	0.9	1.1	1.3	4.7	**18.6**

Scotia Gas Networks - Southern, Ofgem proposed capex and repex

Table A9.19 - Net capex, (£m, 2005-06 prices)

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
LTS & Storage	64.9	75.4	9.7	5.2	6.5	161.8	213.8
Connections	8.2	8.1	8.0	7.9	7.7	39.9	47.1
Mains Reinforcement	13.8	15.6	14.7	13.9	14.5	72.6	71.9
Governors	9.2	9.9	9.8	9.9	10.1	48.9	53.0
Other Operational	6.4	5.2	5.6	3.5	4.1	24.8	27.6
Non Operational	25.5	12.8	10.4	6.1	16.7	71.6	61.8
Total Net Capex	**128.1**	**127.1**	**58.1**	**46.6**	**59.8**	**419.6**	**475.2**
Ofgem Proposed Allowances							
LTS & Storage	25.7	37.4	37.9	31.4	6.6	139.0	141.1
Connections	7.2	7.2	7.1	7.1	7.0	35.6	39.5
Mains Reinforcement	8.7	9.3	9.0	8.5	8.7	44.1	59.5
Governors	8.9	9.1	9.0	9.0	9.0	45.0	49.4
Other Operational	6.0	4.8	5.1	3.1	3.6	22.7	21.8
Non Operational	24.9	12.8	6.8	7.0	16.7	68.3	63.0
Total Net Capex	**81.5**	**80.6**	**74.9**	**66.1**	**51.6**	**354.6**	**374.3**

Table A9.20 - Net repex, (£m, 2005-06 prices)

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	91.8	97.4	106.2	109.9	115.4	520.7	536.9
Services (excl. Riser costs)	52.3	55.8	56.8	57.0	57.6	279.5	316.4
LTS	2.1	16.1	0.3	0.0	0.0	18.5	18.4
Total Net Repex	**146.2**	**169.2**	**163.3**	**166.9**	**173.0**	**818.6**	**871.6**
Ofgem proposed adjustments New Base Case, New Work Load Half Adjustment							
Mains	77.6	79.6	80.8	82.0	83.5	403.5	369.3
Services (excl. Riser costs)	45.0	46.5	45.8	45.2	44.7	227.1	208.2
LTS	2.0	15.2	0.3	0.0	0.0	17.5	17.4
Total Net Repex	**124.6**	**141.3**	**126.9**	**127.2**	**128.2**	**648.1**	**594.8**

Table A9.21 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	3.9	4.8	5.7	6.6	7.6	**28.6**	**67.3**
Ofgem proposed allowances							
UP proposed allowances	2.8	3.4	4.0	4.7	5.4	**20.2**	**67.3**

Wales and West Utilities - Wales and West, Ofgem proposed capex and repex

Table A9.22 - Net capex, (£m, 2005-06 prices)

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
LTS & Storage	18.2	57.0	31.7	16.1	15.1	138.0	111.0
Connections	8.2	8.5	8.8	9.2	9.6	44.3	46.7
Mains Reinforcement	6.8	12.0	7.4	7.7	8.0	41.8	34.5
Governors	1.4	1.4	1.4	1.4	1.5	7.2	9.4
Other Operational	7.5	7.7	6.2	5.9	4.9	32.3	29.5
Non Operational	21.5	13.5	12.5	14.1	16.3	78.0	75.9
Total Net Capex	**63.6**	**100.1**	**68.0**	**54.5**	**55.4**	**341.7**	**306.9**
Ofgem Proposed Allowances							
LTS & Storage	17.9	21.2	13.6	12.2	8.5	73.3	81.3
Connections	6.8	6.9	7.0	7.0	7.1	34.8	30.0
Mains Reinforcement	4.0	6.6	4.1	4.2	4.2	23.1	31.9
Governors	1.3	1.4	1.3	1.3	1.4	6.7	8.9
Other Operational	7.2	7.3	5.7	5.4	4.4	30.0	21.9
Non Operational	17.4	11.0	12.5	14.7	16.3	72.0	69.3
Total Net Capex	**54.7**	**54.3**	**44.2**	**44.8**	**42.0**	**240.0**	**242.7**

Table A9.23 - Net repex, (£m, 2005-06 prices)

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	38.9	41.6	45.4	48.9	50.2	225.1	247.7
Services (excl. Riser costs)	24.9	25.8	26.7	27.5	28.5	133.5	140.6
LTS	3.7	13.9	8.4	7.7	6.2	40.0	36.4
Total Net Repex	**67.6**	**81.3**	**80.5**	**84.2**	**84.9**	**398.6**	**424.8**
Ofgem proposed adjustments New Base Case, New Work Load Half Adjustment							
Mains	36.0	36.8	38.3	39.5	39.7	190.3	223.9
Services (excl. Riser costs)	23.0	22.8	22.6	22.3	22.1	112.8	108.3
LTS	3.6	13.0	7.7	6.9	5.4	36.6	34.0
Total Net Repex	**62.6**	**72.6**	**68.6**	**68.7**	**67.2**	**339.7**	**366.2**

Table A9.24 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	0.9	1.0	1.0	1.0	1.1	**5.0**	6.0
Ofgem proposed allowances							
UP proposed allowances	0.7	0.7	0.7	0.7	0.8	**3.6**	6.0

National Grid Gas - East of England, treatment of historical expenditure

Table A9.25 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Updated proposals main control
NGG EoE	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Alllowed Capex and Non-Mains Repex	197.4	197.4
Total Actual	353.4	337.6
Overspend	156.0	140.2
% overspend against allowances	79%	71%
Allocation of overspend		
Related party margins	4.3	2.7
DN sales costs	0.0	0.0
Under recovery of connections income	7.5	3.3
Inefficient above allowance (Pot 1)	4.1	3.7
Efficient overspend (Pot 2b)	114.5	104.8
Reopener (Pot 3b)	25.7	25.7
Total overspend	156.0	140.2
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	1.9	1.8
Efficient allowed spend (Pot 3a)	195.5	195.6
Total allowance	**197.4**	**197.4**

Table A9.26 - RAV roll forward, (£m, 2005-06 prices)[18]

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	2,115.8					
Additions to pre-2002 assets	18.3					
Revised opening value bf	2,134.1	2,139.9	2,135.6	2,130.8	2,152.0	2,167.0
Depreciation	-74.9	-75.3	-75.6	-75.8	-76.6	-77.3
Net capex additions	83.5	71.4	71.1	97.3	92.7	92.7
Disposals	-2.7	-0.4	-0.2	-0.3	-1.0	0.0
Closing value	2,139.9	2,135.6	2,130.8	2,152.0	2,167.0	2,182.4

[18] In this and subsequent RAV roll forward tables we present the RAV including pots 2 and 3 expenditure, although GDNs do not earn an allowance on the pot 2 portion for five years after the expenditure is incurred.

National Grid Gas - London, treatment of historical expenditure

Table A9.27 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Updated proposals main control
NGG London	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Alllowed Capex and Non-Mains Repex	105.2	105.2
Total Actual	185.3	195.8
Overspend	80.1	90.6
% overspend against allowances	76%	86%
Allocation of overspend		
Related party margins	1.6	1.2
DN sales costs	0.0	0.0
Under recovery of connections income	1.9	1.0
Inefficient above allowance (Pot 1)	2.6	2.4
Efficient overspend (Pot 2b)	72.6	84.7
Reopener (Pot 3b)	1.4	1.2
Total overspend	80.1	90.6
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	0.8	0.8
Efficient allowed spend (Pot 3a)	104.4	104.4
Total allowance	**105.2**	**105.2**

Table A9.28 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,161.5					
Additions to pre-2002 assets	10.0					
Revised opening value bf	1,171.5	1,179.2	1,181.2	1,184.6	1,193.9	1,217.6
Depreciation	-41.1	-41.5	-41.7	-42.0	-42.3	-43.1
Net capex additions	50.3	46.5	45.6	54.7	65.8	66.5
Disposals	-1.4	-3.1	-0.5	-3.5	0.3	0.0
Closing value	1,179.2	1,181.2	1,184.6	1,193.9	1,217.6	1,241.1

National Grid Gas - North West, treatment of historical expenditure

Table A9.29 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Updated proposals main control
NGG North West	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Alllowed Capex and Non-Mains Repex	129.4	129.4
Total Actual	236.0	240.5
Overspend	106.6	111.1
% overspend against allowances	82%	86%
Allocation of overspend		
Related party margins	2.3	1.4
DN sales costs	0.0	0.0
Under recovery of connections income	4.1	1.6
Inefficient above allowance (Pot 1)	6.8	6.6
Efficient overspend (Pot 2b)	92.3	100.3
Reopener (Pot 3b)	1.2	1.3
Total overspend	106.6	111.1
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	0.0	0.0
Efficient allowed spend (Pot 3a)	129.3	129.4
Total allowance	**129.4**	**129.4**

Table A9.30 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,290.1					
Additions to pre-2002 assets	11.1					
Revised opening value bf	1,301.3	1,332.2	1,330.1	1,331.1	1,355.1	1,390.7
Depreciation	-45.7	-46.5	-46.7	-47.0	-47.7	-48.7
Net capex additions	78.2	44.2	47.9	71.3	84.5	68.3
Disposals	-1.6	0.2	-0.1	-0.3	-1.3	0.0
Closing value	1,332.2	1,330.1	1,331.1	1,355.1	1,390.7	1,410.2

National Grid Gas - West Midlands, treatment of historical expenditure

Table A9.31 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Updated proposals main control
NGG West Midlands	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Alllowed Capex and Non-Mains Repex	120.7	120.7
Total Actual	170.7	174.0
Overspend	50.0	53.3
% overspend against allowances	41%	44%
Allocation of overspend		
Related party margins	1.7	1.1
DN sales costs	0.0	0.0
Under recovery of connections income	3.3	1.5
Inefficient above allowance (Pot 1)	1.8	1.7
Efficient overspend (Pot 2b)	32.9	38.6
Reopener (Pot 3b)	10.4	10.4
Total overspend	50.0	53.3
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	0.9	0.9
Efficient allowed spend (Pot 3a)	119.8	119.8
Total allowance	**120.7**	**120.7**

Table A9.32 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,024.6					
Additions to pre-2002 assets	8.8					
Revised opening value bf	1,033.5	1,047.7	1,058.9	1,058.4	1,068.8	1,082.3
Depreciation	-36.3	-36.7	-37.2	-37.3	-37.7	-38.2
Net capex additions	54.5	46.2	36.3	48.0	52.7	45.6
Disposals	-4.0	1.7	0.4	-0.3	-1.4	0.0
Closing value	1,047.7	1,058.9	1,058.4	1,068.8	1,082.3	1,089.7

Northern Gas Networks - Northern, treatment of historical expenditure

Table A9.33 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Updated proposals main control
Northern	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Alllowed Capex and Non-Mains Repex	182.0	182.0
Total Actual	245.2	242.0
Overspend	63.3	60.1
% overspend against allowances	35%	33%
Allocation of overspend		
Related party margins	1.8	1.8
DN sales costs	3.6	3.6
Under recovery of connections income	3.2	1.2
Inefficient above allowance (Pot 1)	3.3	2.1
Efficient overspend (Pot 2b)	44.5	45.7
Reopener (Pot 3b)	6.8	5.7
Total overspend	63.3	60.1
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	1.4	1.4
Efficient allowed spend (Pot 3a)	180.5	180.5
Total allowance	**182.0**	**182.0**

Table A9.34 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,216.2					
Additions to pre-2002 assets	10.5					
Revised opening value bf	1,226.7	1,255.4	1,269.7	1,276.7	1,290.5	1,313.9
Depreciation	-43.0	-43.9	-44.4	-44.8	-45.3	-46.1
Net capex additions	72.4	58.3	51.6	58.5	68.7	72.3
Disposals	-0.5	-0.2	-0.2	0.0	0.0	0.0
Closing value	1,255.4	1,269.7	1,276.7	1,290.5	1,313.9	1,340.1

Scotia Gas Networks - Scotland, treatment of historical expenditure

Table A9.35 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Updated proposals main control
Scotland	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Alllowed Capex and Non-Mains Repex	145.7	145.7
Total Actual	263.5	255.1
Overspend	117.8	109.4
% overspend against allowances	81%	75%
Allocation of overspend		
Related party margins	3.7	2.7
DN sales costs	0.0	0.0
Under recovery of connections income	4.7	2.1
Inefficient above allowance (Pot 1)	4.1	2.2
Efficient overspend (Pot 2b)	101.2	97.9
Reopener (Pot 3b)	4.1	4.6
Total overspend	117.8	109.4
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	0.9	0.8
Efficient allowed spend (Pot 3a)	144.8	144.8
Total allowance	145.7	145.7

Table A9.36 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	759.4					
Additions to pre-2002 assets	6.6					
Revised opening value bf	766.0	789.9	802.7	835.2	884.2	915.1
Depreciation	-26.9	-27.5	-27.9	-28.8	-30.1	-30.9
Net capex additions	50.3	39.0	60.0	77.9	60.9	89.0
Disposals	0.5	1.3	0.4	0.0	0.0	0.0
Closing value	789.9	802.7	835.2	884.2	915.1	973.2

Scotia Gas Networks - Southern, treatment of historical expenditure

Table A9.37 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Updated proposals main control
Southern	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Alllowed Capex and Non-Mains Repex	260.8	260.8
Total Actual	392.1	405.8
Overspend	131.3	145.0
% overspend against allowances	50%	56%
Allocation of overspend		
Related party margins	3.4	2.4
DN sales costs	0.0	0.0
Under recovery of connections income	2.8	1.4
Inefficient above allowance (Pot 1)	8.5	4.3
Efficient overspend (Pot 2b)	108.5	129.7
Reopener (Pot 3b)	8.1	7.2
Total overspend	131.3	145.0
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	1.6	1.7
Efficient allowed spend (Pot 3a)	259.2	259.1
Total allowance	**260.8**	**260.8**

Table A9.38 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	2,029.1					
Additions to pre-2002 assets	17.5					
Revised opening value bf	2,046.6	2,068.3	2,087.3	2,097.3	2,110.0	2,169.3
Depreciation	-71.8	-72.6	-73.4	-73.9	-74.6	-76.3
Net capex additions	95.6	91.2	82.6	86.6	133.9	151.5
Disposals	-2.2	0.4	0.8	0.0	0.0	0.0
Closing value	2,068.3	2,087.3	2,097.3	2,110.0	2,169.3	2,244.5

Wales and West Utilities - Wales and West, treatment of historical expenditure

Table A9.39 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Updated proposals main control
WWU	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Alllowed Capex and Non-Mains Repex	170.6	170.6
Total Actual	329.7	326.6
Overspend	159.1	156.0
% overspend against allowances	93%	91%
Allocation of overspend		
Related party margins	3.0	3.0
DN sales costs	14.1	14.1
Under recovery of connections income	3.7	1.7
Inefficient above allowance (Pot 1)	4.9	2.8
Efficient overspend (Pot 2b)	104.9	105.4
Reopener (Pot 3b)	28.6	29.1
Total overspend	159.1	156.0
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	3.8	3.8
Efficient allowed spend (Pot 3a)	166.8	166.8
Total allowance	**170.6**	**170.6**

Table A9.40 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,038.0					
Additions to pre-2002 assets	9.0					
Revised opening value bf	1,047.0	1,096.4	1,130.2	1,144.1	1,178.1	1,209.8
Depreciation	-36.7	-38.0	-38.9	-39.5	-40.4	-41.4
Net capex additions	85.6	70.5	52.6	73.5	72.1	66.5
Disposals	0.5	1.3	0.2	0.0	0.0	0.0
Closing value	1,096.4	1,130.2	1,144.1	1,178.1	1,209.8	1,235.0

Appendix 10 - Final impact assessment on the opex rolling incentives

Objectives

1.1. The objective of this impact assessment is to consider the merits of introducing an opex rolling incentive. The opex rolling incentive is designed to counteract the effect that the duration of the price control could have on whether the GDNs make opex savings by enabling the GDNs to retain opex savings for five years regardless of when the savings are made.

1.2. The objective of this impact assessment is to further Ofgem's principal objective to protect the interests of consumers. It also helps Ofgem to secure that licence holders are able to finance their authorised activities.

Background

Current arrangements

1.3. Under the current arrangements, we set GDNs' opex allowances for a five year period at the start of the price control. GDNs have incentives to make efficiency savings as they keep any savings they make against their opex allowances for the duration of the price control. These savings may or may not continue into the next price control, depending on how we set allowances and depending on the nature of the savings. However, we do not specifically reward GDNs in the subsequent price control for making savings.

Issues associated with periodic reviews

1.4. One of the concerns with periodic reviews is that they can distort the incentives for GDNs to make efficiency savings. If we set the opex allowances for the next price control based on GDNs' actual costs, then at the start of the next price control the efficiency savings made in the previous control are passed on to consumers. An action taken by a GDN to make recurring opex savings early in the price control will allow it to retain the savings for longer than if it takes the action later in the price control. So it has a stronger incentive to make the saving at the start of the price control, than in the middle of the price control. Since we set the price control in the final year, we do not know the GDNs' actual costs, and so the incentives to outperform are greatest in this year. This is illustrated in figure A10.3 after paragraph 1.33.

1.5. Opex savings typically have "costs to achieve". This may take the form of a capital investment to enable more efficient operations, such as a new IS system. Like any business, the GDN will make a calculation between the cost of the investment and the expected trade-off. The fewer years it expects to retain the savings for, the less likely it is to undertake the investment as it will not pay-off. There is clearly an interaction between capex and opex incentives. Previously, capex incentives also weakened through the price control, which meant that the terms of the trade-off were similar through most years of the price control. We have set out our proposals for a constant incentive strength on capex throughout the next price control. If opex incentives continue to vary, then the distortions are arguably exacerbated.

1.6. The way that the strength of the incentive varies through the price control period is called periodicity. It can distort GDNs' decision-making, so that the reference year for setting the next price control (typically the fourth year) does not represent the most efficient cost base that the GDNs could achieve. This will be reflected in higher charges for customers in the subsequent price control than would otherwise be achievable.

Impact of benchmarking on opex incentives

1.7. As part of the GDPCR proposals we are using comparative analysis, or benchmarking, to set the GDNs' opex allowances. As a result the GDNs' opex allowances are determined by the benchmark GDN(s) and are not based on their own performance.

1.8. Our current approach to setting opex allowances based on benchmarking costs is to apply the benchmark on individual cost activities, known as bottom-up benchmarking, at the upper quartile. For direct costs the analysis is based on the performance of each of the eight GDNs and the upper quartile lies between the second and third top performing GDNs. For indirect costs, which are reported by company group, the analysis is based on the performance of the four ownership groups and is set between the first and second highest performing GDNs. This means that for the GDNs outperforming the upper quartile on each of the cost activities their opex allowances are set above their costs and so they are able to retain their efficiency savings into the next price control period.

1.9. However, we recognised that a benchmark based on the upper quartile bottom-up approach was likely to be challenging as a single GDN was unlikely to be at or out perform against the benchmark for every cost activity. We therefore also undertook a review of the benchmark at the upper quartile on an aggregate basis, known as top-down benchmarking, and uplifted the bottom-up benchmark based on the average difference between the top-down and bottom up approaches.

1.10. The effect of this approach is that the savings that individual GDNs make for the duration of the price control may be retained into subsequent price controls particularly for the companies who do not set the benchmark. We have modelled the impact of a benchmarking approach on GDNs' ability to retain recurring opex savings. Even for the benchmark GDNs, the periodicity effect is muted, as upper quartile benchmarking is dependent on the performance of two GDNs, so only part of their cost savings are lost when allowances are re-set. Non-benchmark GDNs can, in principle, retain their savings indefinitely, as their own costs are not the basis for setting their future allowances. This is illustrated in figure A10.3 after paragraph 1.33.

1.11. Typically, with upper quartile benchmarking, two GDNs set the benchmark out of eight, while if we used frontier benchmarking, it is only one. Even if a GDN sets the benchmark at one price control, there is no guarantee it will do at the next price control, if other GDNs have made greater efficiencies in the intervening five years. It would be rational for GDNs to expect that it is unlikely that they will set the benchmark, and so they can expect, on balance, to keep efficiency savings into the next price control.

1.12. The purpose of the opex rolling incentive is to enable the GDNs to retain opex incentives for five years. There is a risk that some GDNs would earn a duplicate reward for opex savings when the new price control is set. If they had not set the benchmark, they would be retaining any savings they made, while also receiving additional allowances under the opex roller. Moreover GDNs below the benchmark that perform below their allowances could be exposed to duplicate penalties for inefficiency if the rolling incentive was applied symmetrically.

Interaction with capex incentives

1.13. We have set out elsewhere our arrangements for capex incentives. We intend to apply a fixed strength of incentive to capex over/ underspend, regardless of when it occurs within the price control period. This addresses the issue of periodicity with respect to capex incentives. The strength of the incentive varies between GDNs due to the operation of the IQI, ranging from 30 per cent to 35 per cent. This means that a GDN with a capex incentive rate of 33 per cent (taking an approximate middle of the range) is exposed to 33 per cent of any overspend and retains 33 per cent of any underspend. In comparison GDNs are exposed to 100 per cent of an opex over/ underspend.

1.14. We have considered whether the difference in cost exposure could influence the trade off between opex and capex spend. In particular the GDN would retain 100 per cent of an opex saving and would be exposed to (say) 33 per cent of a capex cost. We identified two types of trade-offs. One is a cost allocation issue and the other is a genuine trade-off. Overall our view is that the trade off between capex and opex spend is not clear cut and depends on a number of factors, which we have considered in detail below.

1.15. With regards to the cost allocation issue, in some instances the definitions of opex and capex costs can be unclear and a cost which the GDN would have classified as an opex cost could be reported as a capex cost with the effect that it appears that an opex saving has been made and that capex costs are higher.

1.16. This has been a concern in electricity distribution as companies have historically reported costs differently so it has been difficult to align the way they report the costs and to distinguish whether companies are capitalising opex costs. We consider that these risks are reduced in gas distribution as the separation and sale of the gas distribution businesses occurred recently and GDNs are more likely to have consistent procedures for collecting and reporting on capex and opex costs. On the other hand there are fewer of them, so identifying mis-reporting through comparisons may be marginally harder. As part of this price review we have addressed this through the accounting adjustment exercise. We expect that our annual cost reporting process, which is under development, should minimise this risk.

1.17. There are also opportunities for GDNs to make genuine trade offs between capex and opex spend, for example a GDN could incur the capex cost associated with a leakage management system which would monitor gas flows and reduce pressure off peak which would minimise the opex costs associated with the procurement of shrinkage gas.

1.18. We have reviewed the impact of the trade offs between opex and capex costs so as to assess the extent to which GDNs are likely to make these trade offs. Our views is that the scope for the trade offs are not clear cut and depend on a number of factors such as the investment appraisal period for an opex saving which varies from project to project and the strength and form of the capex incentive which varies from GDN to GDN. Therefore it is not possible to say that the incentives to trade off between capex and opex are in favour of an opex savings except on a case by case basis.

Options

1.19. In this section we consider four options:

- opex rolling incentives for all GDNs;
- opex rolling incentives for benchmark GDNs only;
- partial asymmetric opex rolling incentive; and
- no opex rolling incentive.

Option 1: Opex rolling incentives for all GDNs

1.20. Under this option GDNs earn an opex rolling incentive payment based on their incremental opex efficiency savings. The incremental out performance in any year would be calculated with reference to the highest previous out performance in the price control period. These arrangements ensure that GDNs do not have incentives to load all overspend into any one year of the rolling period. The incentive would be symmetric so GDNs would be exposed to any overspend for the rolling five year period. Figure A10.1 below shows how the rolling incentive would work for underspend against the allowance and A10.2 shows how the rolling incentive would work for overspend against the allowance.

Figure A10.1 - Opex rolling incentive for underspend

	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10	PV
Allowance	100	100	100	100	100						£434.87
GDN performance	90	85	80	75	70						£349.95
Roller Y1	10	10	10	10	10						
Roller Y2		5	5	5	5	5					
Roller Y3			5	5	5	5	5				
Roller Y4				5	5	5	5	5			
Incentive revenue	10	15	20	25	25	15	10	5	0	0	£102.88

Figure A10.2 - Opex rolling incentive for overspend

	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10	PV
Allowance	100	100	100	100	100						£434.87
GDN performance	110	110	120	125	110						£499.45
Roller Y1	10	10	10	10	10						
Roller Y2		0	0	0	0	0					
Roller Y3			10	10	10	10	10				
Roller Y4				5	5	5	5	5			
Incentive losses	10	10	20	25	25	15	15	5			£101.92

1.21. In figure A10.1 the GDN makes year on year savings against its opex allowance. In years 2 and 4 it makes an incremental saving of 5 which is rolled over for a five year period. Year 5's savings are not rolled as these savings would not be known at the time of calculating the rolling incentive revenues for the following price control.

1.22. Figure A10.2 shows a GDN whose performance deteriorates over the five year period. It should be noted that the opex rolling incentive would not affect a GDN who underperformed against its allowance but whose performance improved over the five year period as the rolling incentive takes account of incremental losses. The GDN would be penalised for the first year's under performance for five years without rolling incentives.

Option 2: Opex rolling incentives for benchmark companies only

1.23. Under this option we would apply the opex rolling incentive to the benchmark GDN(s) in recognition that its costs are not retained into the next price control period unlike GDNs who outperform or underperform against the benchmark.

Option 3: Partial asymmetric opex rolling incentives

1.24. In its response to the fourth consultation document NGN proposed a partial asymmetric opex rolling incentive and proposed the same strength capex and opex rolling incentive. In its example NGN suggested an opex rolling incentive of 40 per cent. If the GDN makes an opex saving of £5 million in the third year of the price control it would retain the £5 million saving for each of the three remaining years of the price control and then £2 million for the first two years of the subsequent control.

1.25. If there was a concern that a rolling opex incentive was too strong in comparison to the capex incentive this option could retain some of the properties of a rolling incentive while reducing the strength of the incentive. However, as discussed in paragraph 1.18, it is difficult to determine whether the relative strengths of the incentives lead to distorted decision-making. What can be said is that opex incentives are already strong, and any rolling incentive makes them stronger still, particularly in conjunction with benchmarking.

Option 4: No opex rolling incentive

1.26. This is the no change option.

Competition assessment

1.27. None of the options are likely to have the impact of preventing, restricting or distorting competition as they deal with incentives for monopoly gas distribution companies.

Impacts, costs and benefits

Environment

1.28. None of the options are likely to have an impact on the environment.

Security of supply

1.29. None of the options are likely to have an impact on security of supply.

Health and safety issues

1.30. None of the options are likely to have health and safety issues.

Distributional effects

1.31. Incentive revenues are recovered from GDN charges. The distribution effect of any of the options would have the same effect as any increase or reduction in GDN charges.

Small businesses

1.32. None of the GDNs are small businesses, and small businesses will not be affected disproportionately as proposals would impact all customers' bills equally.

Risks and unintended consequences

1.33. The risks associated with option 1 and to a lesser extent option 3 have been discussed above and are associated with GDNs earning duplicate revenues or penalties through the rolling incentive. The risk associated with Option 4 is that GDNs will continue to behave as if they are subject to periodicity.

Costs and benefits

Issues of periodicity

Figure A10.3 - Impact of periodicity and benchmarking on opex incentives

Year of control	5	1	2	3	4
Years till next control	6	5	4	3	2
Strength of opex incentive: RPI - X	5.3 x	4.6 x	3.7 x	2.9 x	2.0 x
Strength of opex roller incentive for RPI - X	0.0 x	0.0 x	0.8 x	1.7 x	2.6 x
Total opex incentive - for RPI - X	5.3 x	4.6 x	4.6 x	4.6 x	4.6 x
Alternative - upper quartile benchmarking incentive and **no opex roller**					
Strength of opex incentive - upper quartile GDN	6.8 x	6.4 x	5.9 x	5.5 x	5.1 x
Strength of opex incentive - non-benchmark GDN	8.2 x	8.2 x	8.2 x	8.2 x	8.2 x

1.34. Figure A10.3 above illustrates the impact of benchmarking and periodicity on the incentives for GDNs to make opex efficiency savings. In this example we have assumed that an opex saving can be made for a maximum of 10 years and the WACC is 4.84 per cent. The top two rows show the year that the opex saving is made and the number of years than an opex saving is retained for. The third row shows how a company, in the absence of benchmarking and opex rolling incentives, would retain 4.6 times the value of a recurring opex saving in PV terms if it made savings in the first year of the price control and only 2 times the saving if it were made in the fourth year of the price control.

1.35. The fourth and fifth rows show the impact of a five year rolling incentive on the GDN - the GDN would retain the savings as if it had been made in the first year of the price control regardless of when the saving was made, although the GDN retains a stronger incentive to make an efficiency saving in the final year of the price control.

1.36. The final two rows show the impact of the benchmark arrangements on a company without rolling incentives. For an upper quartile GDN with opex costs that are used to set 50 per cent of the benchmark, it would be subject to periodicity on half of its savings and would retain the other half for the duration of the next price control (i.e. 10 years). The last row shows the impact on a company that either outperforms or under performs but never sets the benchmark. It would retain the opex savings into subsequent price controls as these savings are not passed on to consumers and in the example it retains 8.2 times the opex saving regardless of when the saving is made.

1.37. The analysis shows that without the opex rolling incentive GDNs out-performing or under-performing against the benchmark are able to retain the savings they make for longer than the duration of the price control and that these savings are higher than if we had an opex rolling incentive without benchmarking.

1.38. The rolling incentives have been proposed so that GDNs are not influenced by the strength of the incentive in any particular year before making an efficiency saving. However, if it is only the benchmark GDN who does not retain its savings into the next price control period and the GDNs will not know at the time of making the decision whether they are at the benchmark it is likely that their decision is not affected by periodicity. Thus although option 4, unlike the other three options does not specifically address periodicity, our comparative approach to setting price control allowances means that periodicity is much less of an issue than previously.

The relative strength of the opex incentives compared to capex incentives

1.39. As discussed in paragraphs 1.17 above we have considered whether the relative strength of the capex and opex incentives are skewing the GDNs' decision on whether to make a capex or opex saving. We consider that this is likely to be affected by a number of factors such as the investment appraisal period, which will be different for each trade off opportunity. It is therefore not possible to say that the opex incentives are stronger than the capex incentives except on a case by case basis.

Opportunity to game the rolling incentives

1.40. Under option 2 the opportunities to game the opex rolling incentive are low as the rolling incentive only applies to benchmark companies and they will not know in advance whether they are likely to be the benchmark company. Under option 1 the incentive is symmetrical so the scope for gaming is minimal. Under option 3 there is a risk that GDNs could mis-report their costs to inflate costs in areas where they are underperforming against their allowance (as they are not penalised though the rolling incentives) so as to report lower costs in areas where they are likely to beat the allowance in order to benefit from the rolling incentives. This places greater pressure on the accuracy and consistency of cost reporting.

Duplication of rewards for efficiency

1.41. Under options 1 and 3 GDNs who out-perform or under-perform the benchmark can retain the savings they make into future price control periods. A rolling incentive will duplicate the rewards for efficiency. Under option 2 there is no duplication of rewards for efficiency as the rolling incentive applies to benchmark companies only.

1.42. Under option 1 the incentives are symmetric so underperforming GDNs would be subject to duplicate penalties for inefficiency from the setting of allowances which do not reflect their costs as well as from the penalties of the rolling incentive.

1.43. Some GDNs have raised concern that in the absence of a rolling incentive, they do not believe they have appropriate incentives to make efficiency gains. The analysis above should have demonstrated why this is not the case. In particular, under upper quartile benchmarking, the frontier company does not set the benchmark, and therefore any savings it makes are retained into the next price control period in any case. It also enjoys the benefits of already being more efficient than the level at which allowances are set (subject to the impact of productivity assumptions) and so is in a stronger position to keep outperforming allowances into the next price control. If we were to adopt frontier benchmarking, then it may be appropriate to consider additional rewards for frontier performance.

Implementation and transparency issues

1.44. There are likely to be a number of implementation issues which we will need to resolve for any of the opex rolling incentives, for example to determine which costs should be included such as atypical costs, TMA costs, shrinkage costs etc. Option 2 is the most complex to implement. Since benchmarking has been applied at an activity level the opex rolling incentive would also have to be applied at this level and different GDNs are likely to set the benchmark for different activities. This also places greater reliance on the accuracy and consistency of cost reporting.

1.45. Option 1 is less complex to implement however some of the implementation issues above would still apply. Under option 3 there are complexities associated with the calculation of the partial rolling incentive, particularly if the strength of the partial rolling incentive is the same as the capex rolling incentive and varies with each GDN. Given the complexities of implementing an opex roller, and the fact that the benefits of removing periodicity are small when benchmarking on its own has reduced the impact of periodicity option 4 is likely to be the best option.

Conclusion

1.46. A summary of the costs and benefits of the options is set out in table A10.1 below.

Table A10.1 - Summary of the costs and benefits of the options

	Minimises periodicity	No/ low opportunity for gaming the roller	Does not duplicate rewards for efficiency	Ease of implementation & transparency
Option 1 – Symmetric opex roller for all GDNs	✓	✓	×	✓
Option 2 – opex roller for benchmark GDNs only	✓✓	✓	✓	××
Option 3 – Partial asymmetric opex roller for all GDNs	✓	×	×	×
Option 4 – No opex roller (with benchmarking)	-	-	✓	✓✓

Appendix 11 - Initial impact assessment on the loss of meter work revenue adjustment

Background

1.47. In chapter 6 of the main document we set out the rationale for the loss of meter work revenue adjustment. In summary GDNs are obliged to provide emergency services to customers. As a consequence of having sufficient staff to respond to an emergency within 1 hour staff may be unused at any point in time. GDNs minimise the costs of providing emergency service staff by finding additional work (infill work), predominately metering related work, for them to carry out in their unused time which they can leave at short notice in order to attend an emergency.

1.48. GDNs have argued that there is little other infill work available and have forecast that they will lose approximately 90 per cent of their meter work by 2012-13 as metering competition develops. They estimate that this will add £40 million per annum. or 45 per cent to emergency costs by 2012-13. To date most of the GDNs have already lost significant amounts of meter work between 2005-06 and 2006-08 but without an impact on costs. We note that initially metering workload can be lost without an impact costs for example by releasing contract labour used for metering work only.

1.49. There are a number of options available to address the costs to emergency services from the loss of metering. This initial impact assessment sets out an initial cost benefit analysis of the options. It also sets out the further work we will undertake as part of the final impact assessment which we intend to publish as part of the GDPCR final proposals in December 2007.

1.50. Our initial view is that a loss of meter work revenue driver is appropriate and chapter 6 of the main document set out the issue and the proposed parameters for the revenue driver.

Options

1.51. The options we are considering are:

- option 1 - do nothing. We would set a baseline allowance for the provision of emergency services assuming that insufficient metering work is lost to significantly impact the costs of providing the emergency service.
- option 2 - an ex ante adjustment to baseline allowances. We would set baseline allowances taking account of the GDNs' forecast loss of metering.

- option 3 - an ex ante adjustment to baseline allowances with ex post revenue adjustment. We would set baseline allowances taking account of the GDNs' forecast loss of metering. If the amount of metering work lost is actually greater or less than forecast customers are exposed to 75 per cent of the savings/ costs associated with the difference in workload and GDNs are exposed to 25 per cent of the savings/costs based on an ex ante assessment of the incremental costs of loss of metering. This option was proposed by NGG.

- option 4 - an ex post adjustment to the baseline allowance through a revenue driver. We would set the baseline allowance assuming that there are no meter work losses with a revenue driver adjustment based on an ex ante determined unit cost associated with meter work losses. The revenue driver would only apply when the GDN incurs significant incremental costs, at the tipping point. This is our preferred option and table 6.4 in the main document sets out our proposed parameters for this option.

Initial qualitative analysis

Windfall gains and losses

1.52. As there is uncertainty associated with the volume of metering lost and the timescales for these losses with options 1 and 2 there is a risk that GDNs will make windfall gains or losses (in the case of option 1 the risk is only associated with windfall losses). Under options 3 and 4 an adjustment is made for actual metering volumes so the risk is lower. However, under option 3 GDNs are exposed to 25 per cent of any gains or losses.

Incentives to retain/find infill work

1.53. Since allowances are fixed ex ante, options 1 and 2 maintain full incentives to bid to retain metering services after the current contracts expire, and to find additional infill work if metering work is lost. Under options 3 and 4 the incentives to retain or find new metering work is reduced as GDNs are insulated from the risks of windfall gains and losses, although under option 3 the incentives could be strengthened by changing the sharing factors.

Funding only where the loss of metering results in significant additional costs

1.54. Under option 3 the baseline allowance is set taking account of GDN forecast for metering losses and a single unit cost per metering job lost does not take account of the fact that a certain amount of metering work may be lost before there significant incremental costs are incurred i.e. the relationship between additional costs and metering is not linear. In comparison option 4 this problem as the revenue driver only applies when metering volumes reach the tipping point. This is not applicable for option 1 as no allowance is made for metering losses. Under option 2 we could set the baseline allowances to take account of when we consider the tipping point is likely to arise but as this is a forecast it is possible that metering losses could be funded before actual costs are incurred.

Simplicity

1.55. Options 1 and 2 are the simplest options to implement. Option 3 is more complex as we would need to calculate the incremental cost per infill job lost for each GDN. Option 4 is also complex as we need to calculate the tipping point for each GDN as well as calculating the unit cost per metering workload lost once the tipping point is reached.

1.56. Table A11.1 summarises the costs and benefits of each option as discussed above.

Table 11.1 - Loss of meter work revenue adjustment

	Minimises risk of windfall gains and losses	Provides incentive to retain/ find infill work	Additional allowance only where the loss of metering results in significant additional costs	Simplicity
Option 1: no change	×	✓	n/a	✓
Option 2 – ex ante adjustment to baseline allowance	×	✓	×	✓
Option 3 – ex ante adjustment to baseline allowance with revenue adjustment	✓	×	×	×
Option 4 – ex post adjustment to baseline allowance through revenue driver	✓✓	×	✓	××

1.57. Our initial view is that a loss of meter work revenue driver is appropriate and chapter 6 of the consultation document set out the issue and the proposed parameters for the revenue driver.

Further analysis

1.58. We will undertake further analysis to quantify the costs and benefits of the four options discussed above where possible.

Appendix 12 - Impact Assessment on the introduction of an Innovation Funding Incentive (IFI)

Objectives

1.1. The objective of this impact assessment (IA) is to consider the merits associated with a number of options for encouraging GDNs to carry out research, development and demonstration (RD&D).

1.2. The primary objective of introducing an incentive is to secure benefits for consumers. This IA considers the current levels of GDN investment in RD&D, the impact of regulatory frameworks in this area, the potential for RD&D and the likely benefits that it could deliver.

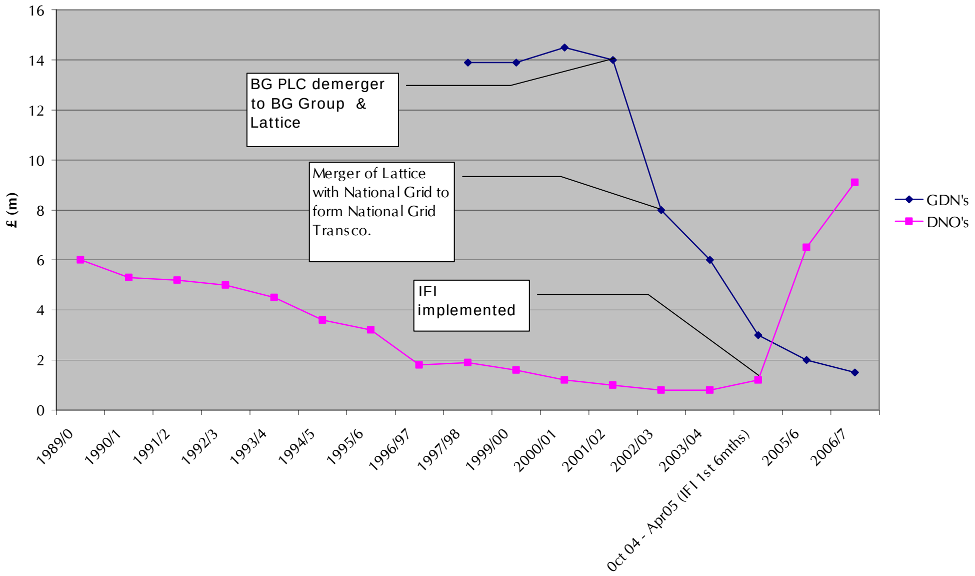
1.3. This IA draws upon Ofgem's experience of the innovation funding incentive IFI with the electricity distribution network operators DNOs where the incentive mechanism has been in operation since October 2004.

Background

1.4. Since early in 2002, Ofgem has been exploring the broad issue of technical innovation in the DNOs. The Innovation Funding Incentive (IFI) was introduced as part of the electricity distribution price control review (DPCR) in October 2004 to address concerns that DNO expenditure on research, development and demonstration (RD&D) had declined to the extent that opportunities for opex and capex efficiency gains were being lost. Considerable evidence pointed to the opportunity for engineering innovation to bring fresh thinking, releasing greater value through adoption of new techniques, tools and materials.

1.5. In the period leading to the electricity distribution price control review implemented in April 2005, Ofgem explored the impact of price regulation on RD&D activity. Evidence from the sector revealed the extent of reductions in RD&D spending since privatisation. This has been mirrored in gas distribution as shown in figure A12.1.

Figure A12.1 - RD&DRD&D / IFI Profile for GDNs and DNOs

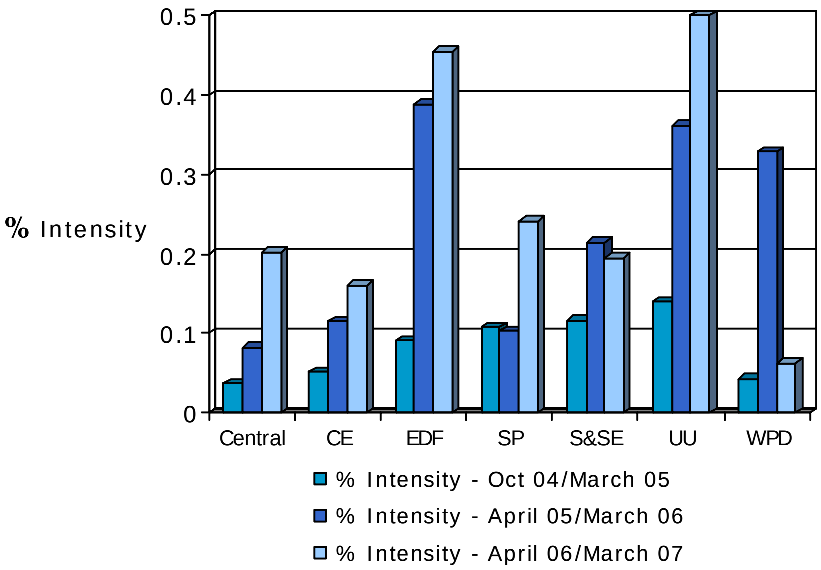


Source: Ofgem IFI reports and DTI Gas R&D scoreboard – with gas distribution disaggregated

1.6. The level of a company's investment in R&D is commonly stated as its R&D Intensity. This is the ratio of R&D expenditure to company turnover. DBERR tracks R&D Intensity for different industrial sectors in the UK and internationally. The results are published annually as their R&D Scoreboard[19] following the introduction of IFI.

[19]DBERR's R& D Scoreboard – http://www.innovation.gov.uk/projects/rd_scoreboard/

Figure A12.2 - DNO R&D Intensity following the introduction of IFI



1.7. There are a number of reasons why companies may have chosen to reduce their expenditure on RD&D. The strength of the RPI-X incentive is valuable in encouraging cost savings that can be passed back to consumers at subsequent reviews. The incentives are especially strong for operating expenditure, which RD&D is classified as for price control purposes. However innovation often has timescales longer than price control cycles, both in its execution and its deployment, which may mean that a GDN does not expect to retain the benefits of RD&D expenditure for long enough to justify the initial investment. This is exacerbated by the riskiness of RD&D, where not all projects are likely to generate a return.

1.8. Our assessment of the introduction of IFI to the DNO sector is that it is proving effective in re-engaging management attention to innovation opportunities. The DNOs' latest returns show forecast net benefits of £46 million for 2006-07. While there is uncertainty about future benefits, this level of return is considered to be reasonable for engineering innovation. In practice it can be expected that some projects in an RD&D portfolio will under-perform or fail, while others will succeed or deliver returns significantly beyond expectations.

1.9. In view of the positive response to the DNO arrangements, the Transmission Price Control final document in December 2006 stated that an IFI mechanism would be implemented for electricity and gas transmission companies. This is now operating but no information is yet available to judge its effectiveness.

1.10. The Third Gas Distribution Price Control consultation document published in November 2006 stated that it was not clear at the time that there was a need for IFI in gas distribution and views were invited. We received wide interest in IFI with 25 responses from a cross section of industry. The responses were submitted from consultants, GDNs, shippers, suppliers and other industry bodies.

1.11. Analysing the responses, those supportive of IFI gave arguments for their position and in some cases provided examples of areas where innovation could be expected to bring particular value in the medium and longer term. These areas encompassed: security of supply, environment, gas quality, asset management, safety, pipeline renovation, maintaining system integrity, street works, data and records management, and communications.

1.12. The responses brought out an important clarification: while there is clear evidence today of innovative techniques being developed and deployed, by mains installation contractors for example, these are nevertheless innovations that had their genesis many years ago. The concern identified is for tomorrow's innovations which need RD&D activity encouraged now, as the lead time between research and deployment can be some 5 to 7 years or longer.

1.13. In our initial proposals document of May 2007[20], we noted that GDNs have expressed support for separate funding for areas such as skills and training, and research and development. They have argued that these costs can lead to long term savings, from which consumers should ultimately benefit, but the savings may take some time to occur. The case was put to us that the strength of opex incentives discourages GDNs from taking the necessary long term outlook. In the May document we stated that if there was merit in these arguments, an opex rolling incentive might, under certain conditions, potentially address the concerns without the need for separate incentives.

1.14. From the responses we have noted the weight of industry opinion expressed in favour of an IFI arrangement rather than a rolling incentive mechanism. Since the publication of the initial proposals document, Ofgem has been contacted by all the GDNs to explain their support for IFI and also to share with Ofgem their views of the engineering challenges ahead, and why they believe IFI is appropriate. The GDNs commented that the efficiency pressures that constrain opex budgets would be likely to continue to restrict RD&D under the mooted rolling opex mechanism.

1.15. The GDNs expressed the view that while an opex rolling incentive may help address the timing/cyclic barrier to innovation, it lacks the ‘indirect influences’ of the IFI framework that creates an enhanced profile for innovation, and the visibility of projects that encourages management engagement and inter-company collaboration.

1.16. An important consideration in the original decision to introduce the IFI for the DNOs was the prospect of a major step-up in capital expenditure, including

[20] Gas Distribution Price Control Review – Initial Proposal 125/07

investment in support of generation projects connecting to the distribution networks (known as distributed generation, or DG). Similar considerations were relevant to electricity transmission. There is however no directly equivalent large scale change of circumstances in the case of gas distribution and the case for following an identical model for IFI is therefore less clear cut.

1.17. While the GDNs are not faced with the challenges of DG, the consultation responses have, nevertheless, drawn attention to a number of material and demanding issues that need to be addressed in the medium and longer term, and for which technical innovation can be expected to provide solutions. These issues are set out in the later part of this IA and include environmental challenges such as gas shrinkage and its carbon impact, and asset management challenges such as ongoing mains replacement (larger diameters) and riser replacements.

Key Issues

1.18. Key issues that we have considered in the design for an innovation incentive for gas distribution are as follows:

- potential benefits to gas consumers in the medium and longer term;
- scope, scale and materiality of the technical challenges identified;
- extent of the parallels as regards innovation between the DNOs and GDNs;
- experience to date of the IFI associated with the DNOs;
- extent of the suitability of the DNO IFI mechanism for gas distribution; and
- Ofgem's duties with respect to promoting sustainable development.

Options

1.19. Against this background, we have considered the following three options:

- option 1 - A continuation of the status quo (do nothing approach) resulting in a traditional R&D component forming part of the GDNs' opex allowances; and
- option 2 - Implementation of an IFI incentive mechanism on a similar basis to electricity distribution but more focused towards sustainable development issues.

1.20. The assessment has been made by considering the impacts of implementing option 2 as compared with option 1.

Option 1 - Do Nothing: R&D opex allowance

1.21. Maintaining the status quo would avoid introducing a new targeted incentive mechanism. This would reduce complexity and avoid the risks associated with the regulator becoming more closely involved in setting the priorities for the companies' management agendas. However, there is little evidence to indicate that the downward trend in RD&D of recent years will be reversed under a no change option and the benefits to gas consumers of cost-effective innovation are likely to be small.

Option 2 - Innovation funding incentive for sustainable development (IFI/SD)

1.22. As set out in this document, the DNO IFI framework is showing evidence of stimulating beneficial changes. In a number of regards there are parallels between gas and electricity distribution networks that give reasonable encouragement that an IFI-like framework would be effective for the GDNs. However there is also a distinctive difference in that the DNO IFI scheme was in part introduced to respond to the challenges of renewable energy and distributed generation; this particular network architecture challenge does not apply to the GDNs.

1.23. However, the GDNs face significant challenges of their own for the medium and longer term, as has been identified by the views of respondees to our earlier consultation. Topics that we agree could helpfully be addressed by technical innovation include environmental challenges such as gas shrinkage and its carbon impact, and asset management challenges such as ongoing mains replacement (especially larger diameter mains) and riser replacements.

1.24. We have considered whether the GDN innovation incentive should be restricted only to "green" projects in view of the government's priorities on sustainability,[21] Ofgem's duties in this regard and concerns that external market mechanisms such as the European Union Emission Trading Scheme (EU ETS) are relatively new and the long tern signals emerging from them may not be sufficiently strong.

1.25. On balance our view is to restrict incentive funding to projects that align with one or more of Ofgem's five published sustainable development (SD) themes. The themes have a reasonably broad description, so alignment with them will ensure a focus on sustainability while leaving a measure of discretion for the companies. This approach leaves some flexibility for the unknown and should ensure that a breadth of innovation capability is developed in the companies through in-house skills and external relationships.

1.26. In summary, the IFI/SD is modelled on the DNO IFI framework but designed to promote innovation targeted at sustainable development. The key elements proposed are as follows:

- GDNs will be permitted to spend up to 0.5 per cent of their regulated turnover on technical innovation, on a use it or lose it basis;
- the companies may pass 80 per cent of the cost of each project to their customers through this mechanism and are required to fund the remaining 20% themselves;

[21] For example, the Energy White paper see www.berr.gov.uk/files/file39387.pdf
Which sets out the following headline priorities:
- to put ourselves on a path to cutting CO2 emissions by some 60% by about 2050, with real progress by 2020;
- to maintain the reliability of energy supplies;
- to promote competitive markets in the UK and beyond;
- to ensure that every home is adequately and affordably heated.

- a mechanism will be established to carry over up to 50 per cent of unused eligible IFI funds from year to year, but not cumulative carry over;
- all innovation projects in the GDN portfolio must be aligned with one or more of Ofgem's five published SD themes[22];
- for clarification, the proposed IFI framework includes innovative gas engineering/technical projects that deliver benefits in safety;
- internal GDN expenditure will be initially capped at 15 per cent;
- the projects must be openly reported to Ofgem annually;
- IFI/SD regulatory instructions and guidance (RIGs) will be established; and
- the GDNs are required to develop a good practice guide (GPG) for gas distribution, and submit it to Ofgem for approval.

Impacts, Costs and Benefits

The DNO Innovation Funding Incentive - experience and parallels

1.27. The DNOs and GDNs have close similarities as operators of utility networks, comprising extensive capital assets with long lives. There are a number of synergies and parallels associated with operating and managing these assets through their life cycle. There are similarities in the challenges that they face as both sectors are required to operate in a safe and efficient manner whilst being measured by the reliability and quality of service they provide. Furthermore, they both have to maintain and implement long term strategic asset management and replacement plans. This includes for example: planning, procurement, asset replacement, network extensions, street works, handling and processing of hazardous materials, management of contaminated land, asset condition and monitoring, leakage / loss management. They share the engineering and management challenge that assets continuously degrade, eventually affecting their serviceability and driving their need for replacement.

1.28. For the purposes of this IA it is judged pertinent to note the experience to date under the electricity distribution IFI, to acknowledge the many parallels between electricity and gas distribution, and conclude that the benefits to customers now emerging from IFI in electricity can reasonably be expected to follow in gas distribution if a similar framework is adopted.

1.29. The DNO IFI allows the distribution companies to spend up to 0.5 per cent of their regulated turnover on engineering innovation on a use it or lose it basis. The companies pass 80 per cent of the cost of each project to their customers through

[22] 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

this mechanism and fund the remaining 20 per cent themselves. The projects are reported in the public domain through Ofgem's website which encourages sharing of best practice and collaboration. Ofgem does not approve individual projects and the self-regulation aspect of this is proving successful with a range of good quality projects being evident. Examples of active and completed DNO projects recently reported are set out in table A12.1.

Table A12.1 - IFI DNO Project Examples

IFI DNO Project Experience: The total number of major projects reported by the DNOs in their 2006/7 IFI Annual Reports is over 180. The majority of these projects involve cooperation with third parties; manufacturers, universities and other DNOs. Some projects are reported by more than one DNO but this double-counting is balanced by the fact that some projects may be regarded as actually a collection of smaller projects. This is particularly the case with EA Technology's Strategic Technology Programme.
Examples of projects that are currently in train include the following:
> Collaborative research programmes involving all DNOs through EA Technology into issues relating to overhead lines, cables, substation equipment and distributed generation. > The development of fault current limiting devices using new technologies. Improved fault current detectors with communications capability. > A study of the potential impacts of climate change on distribution networks. > The development of a remote controlled (using a mobile phone) LV fault-making switch to aid fault location.
Encouragingly, we are now seeing IFI projects completed and delivering outputs that are being adopted by the companies. There are over twenty examples of this quoted in the DNOs' reports including the following:
> Very high resolution photographic surveys of overhead line fittings using helicopters. > More sophisticated health indices for high voltage switchgear delivering better focus for maintenance/replacement. > Intelligent mobile phone systems that identify the location of personnel when unscheduled switching is required, usually post-fault to restore supplies. > Partial discharge detection in underground cables being used to support preventative replacement and avoid in-service disruptive failure. > New analysis technique for circuit breaker performance to identify 'sticky' units, a cause of equipment failure. > Use of fibre optic communications networks in substations to reduce costs.

1.30. The 0.5 per cent intensity limit is equivalent to a maximum annual spend of £16.4 million (2006-07) for the electricity distribution companies in total, £6.1 million for electricity transmission and £2.4 million for gas transmission. In practice, expenditure is still building up in the case of the DNOs and amounted to a total of £9.1 million in the period 2006-07.

1.31. While Ofgem reserves the right to audit projects, the self-regulating framework is largely achieved by the companies complying with a good practice guide (GPG). The companies produced a common guide that Ofgem endorsed and this is available through the ENA[23]. The guide addresses the evaluation of benefits and requires that an estimate is made of the net present value (NPV) of each project. It outlines methods to factor in the probability of success and the duration of the benefits. Experience has shown that capturing benefits in this way has limitations and for some projects is more difficult than others. The GPG is currently being updated and will be re-issued shortly; it will include a wider remit that encompasses environmental aspects and also a balanced scorecard approach. These and other issues arose from the DPCR4 mid-term review that was undertaken for IFI and RPZ operational experience.

1.32. By ring-fencing the RD&D allowance and attaching a 'use it or lose it' condition the risk to the consumer of under-spending an R&D element within a traditional opex allowance is significantly reduced. This is the basis of the IFI framework. It is considered that this approach offers a risk profile for a DNO that is consistent with its business model (depending on the level of pass-through and the actual costs that are allowable). At the same time it offers consumers the potential benefits that innovation can bring together with a reasonable level of financial protection. There remains a risk that the allowed expenditure may deliver little or no value, however this is perceived to be small, particularly now that good DNO experience is being demonstrated through annual reporting. The requirement for DNOs to part-fund IFI projects and the potential rewards should reduce this risk. Ofgem also recognises the value of collaborative projects involving other parties sharing the costs with a DNO. The majority of DNO IFI projects are co-funded in this way.

Considering IFI/SD by impact areas

Probably the most significant aspect of the IFI/SD proposal is the renewed focus it can be expected to provide on the five Ofgem SD themes, bringing forward innovative solutions for the medium and longer term. The output from the analysis of the DNOs' IFI projects is encouraging; the majority of the projects demonstrate retrospectively an alignment with the Ofgem SD themes. Taking each impact area in turn:

Environment

1.33. Several of the SD themes focus on delivering environmental benefits: managing the transition to a low carbon economy, promoting energy saving and supporting improvement in all aspects of the environment. In chapter 7 we set out proposals that will incentivise the companies in the shorter term to address with new priority the challenges arising from shrinkage gas and the carbon consequences associated with it. In this regard the IFI/SD proposals are helpfully aligned, and can be expected to maintain momentum on this important issue for the medium and longer term.

[23] ENA Engineering Recommendation G85 Innovation in Electrical Distribution Network Systems: A Good Practice Guide www.energynetworks.org

Security of supply and sustainable development

1.34. One of the SD themes is that of ensuring a secure and reliable gas and electricity supply. In the medium and longer term, IFI/SD can be expected to enhance security of supply for gas distribution. GDNs have indicated a number of areas in which innovation can be expected to bring forward new solutions. This includes initiatives relating to the mains replacement programme, to replacement of risers, to condition monitoring and whole life asset management.

Health and Safety Issues

1.35. Health and safety has not been a primary driver of the development of IFI/SD. This is because health and safety has a long established priority in the network companies and is actively managed. On the other hand, we do not see any adverse health and safety issues relating to IFI/SD, and indeed it is likely that projects within the IFI portfolio will help further to reduce risk in some areas of activity.

1.36. Ofgem is separately considering as part of the price control whether there would be enhanced safety benefits if the GDNs' Emergency Service personnel carried carbon monoxide measuring equipment during gas emergency investigations. This will enable the presence and levels of this dangerous gas in the atmosphere within the affected and adjacent properties to be quantitatively established and appropriate action taken. Further developments in the medium and longer term might be expected to take place and IFI/SD may make a positive contribution.

Distributional Effects

1.37. One of the SD themes is eradicating fuel poverty and protecting vulnerable customers. While this is an area where there may be less scope for RD&D to make a difference, any projects that are aligned with this them will qualify for IFI funding. In any case, we do not see any adverse distributional effects relating to IFI/SD. Consumers and GDNs will share the funding of innovation projects and it is anticipated that both groups will gain benefits. This aspect will be kept under review as experience with the incentive is gained.

1.38. Collaborative project working is expected, based on DNO experience, and this will be helpful in gaining funding leverage and reducing costs and risks to all parties.

Review and Compliance

1.39. The proposed open reporting of the IFI projects on Ofgem's website, combined with Ofgem’s ability to selectively audit projects is expected to ensure compliance with the objectives of this incentive. We expect the IFI to be largely self-regulating through the mechanism of the Good Practice Guide. No material issues have been identified relating to review and compliance.

Risks and Unintended Consequences

1.40. Under the IFI/SD framework it is considered probable that the GDNs will realise a ratio of costs to returns at least as strong as expected from the DNOs.

1.41. The alternative option to do nothing carries a greater risk that the trend in declining innovation activity would not be changed; that the GDNs would continue to develop their networks by applying extant technology; and potential efficiency gains will be lost to consumers for the medium and longer term. Environmental gains would similarly be jeopardised.

1.42. By the nature of innovation, there remains a risk that IFI/SD funding will be properly spent but not deliver benefits that produce an acceptable return. This is the case with RD&D expenditure in any business. However, whereas in a competitive environment the shareholder takes this risk, under IFI the consumer takes the larger part of it.

1.43. Additionally, there is a possibility that expenditure that would have been carried out in any case is reclassified by the GDNs as qualifying RD&D, so that the consumer gains no incremental benefit from the higher allowances paid to the GDNs. Ofgem therefore regards it as a priority that adequate controls and safeguards are put in place to limit consumers' exposure to these risks. The experience of IFI to date gives confidence that the framework provides sufficient consumer protection.

1.44. As a condition of allowing IFI/SD expenditure, each GDN will be required to participate in and comply with an industry good practice guide to innovation management. It will also be required to produce a public domain annual report of its IFI/SD activities. This report will describe the work being carried out, its relevance in terms of potential consumer benefit, the money spent in the reporting year, the alignment with the Ofgem five SD themes and the planned activities and budget for the next two years. This will promote best practice between companies and act as a driver for high quality activity. Compliance with the good practice guide can be audited by Ofgem.

1.45. A review of the IFI/SD mechanism will be carried out by Ofgem after the publication of the First annual reports (2009). At this stage, the level of funding will be reviewed for each company. Ofgem will retain the option to audit IFI/SD activities and to vary the IFI/SD cap for a GDN if considered necessary.

1.46. Projects in each GDN's IFI/SD Portfolio will need to be aligned with one or more of the five Ofgem SD themes. This focus is judged to help reduce the risk that money is spent inappropriately on RD&D.

1.47. IFI/SD activities will be openly reported. The likelihood of unintended consequences of real materiality is small.

Competition

1.48. Ofgem do not consider there to be any material issues in relation to competition. Ofgem expect that the IFI/SD will encourage the companies to work collaboratively in some areas. This is expected to promote industry-wide sharing of new ideas for the longer term. However, there is scope for companies to work alone and if their performance improves as a result it will assist Ofgem in the future comparisons between companies. There are parallels here with companies in the fully competitive sector (e.g. electricity and gas asset manufacturers); in this case the companies not uncommonly collaborate on a strategic (long term) level and compete on a short term, strategic level.

Costs and benefits

1.49. If IFI/SD funding is fully taken up, assuming an 80 per cent pass through, the average annual cost to consumers would be around £10 million. It is essential to ensure that the benefits that result from IFI/SD projects are shared appropriately with consumers and this would be achieved through normal price review mechanisms.

1.50. The DNO IFI data within table A12.2 demonstrates that the DNOs have forecast to date a benefit of £46 million.

1.51. The IFI scheme has encouraged DNOs to invest in wider technical innovation so as to deliver benefits to consumers in the medium and longer term. It is encouraging to note that the scheme has already had a significant impact on the level of innovation activity amongst the DNOs, through approximately 180 projects and a more than doubling of the level of RD&D intensity across areas that encompass condition assessment of existing assets, fault location and future network architectures to accommodate distributed generation.

1.52. It is understood from Ofgem's discussions with the GDNs that they have several focus areas that they anticipate will benefit from IFI/SD, including:

- shrinkage;
- security of supply;
- gas quality;
- safety;
- asset management;
- pipeline renovation techniques;
- maintaining system integrity;
- street works;
- environment; and
- data and records management and communications.

1.53. GDNs are having increasing difficulty in recruiting and retaining new graduates, qualified with suitable engineering disciplines, into their businesses. Greater involvement in innovation will, arguably, raise the intellectual challenge and opportunities for professional engineers and have a wider positive effect.

Analysis

1.54. RD&D activities deliver knowledge that, when applied, is expected to produce value in excess of its cost. No definitive cost/benefit analysis can be carried out to prove ex-ante that RD&D investment will deliver appropriate returns as, by definition, RD&D has an element of uncertainty. However, it is possible to assess scenarios of potential value that RD&D could deliver, combined with the likelihood that a successful outcome will be achieved, to allow an estimate of its financial value to be obtained.

1.55. Within the RIA for the 2004 Electricity Distribution Price Control Review[24], an independent assessment of the value of innovation was carried out by Mott MacDonald and BPI[25] assessed 20 innovative projects related to improvements in asset management, control and communications and a number of specific technological developments.

1.56. The estimated potential benefit was factored by the likelihood of success, the expected date of deployment and the lifetime of the benefit to calculate a PV. Summing these estimates for the identified IFI innovations gives a total PV of £443 million, against an investment of £57 million.

1.57. The impact of the IFI funding and benefits are set out in table A12.2.

Table A12.2 - IFI budgets and performance

Company	£m IFI Maximum	£m IFI Actual	£m IFI Benefits Forecast
DNOs	16.4 (2006-07)	9.1 (2006-07)	45.8
Gas Transmission	1.9	No spend yet reported	-
Electricity Transmission	5.0	No spend yet reported	-

1.58. In the gas distribution sector, 0.5 per cent of turnover would be equivalent to total spending of circa £12 million per annum, of which 80 per cent would be borne by consumers.

1.59. The actual DNO IFI returns can be found in table A12.3. Ofgem will continue to monitor the overall returns and recognises that it is still early days for work programmes that in some cases extend over a number of years. The DNOs and GDNs operate capital intensive businesses that have similar challenges associated with sustainable development and asset management. The DNOs have commissioned in the region of 180 IFI projects to date since 2004, of which a large majority of the projects align with Ofgem's SD theme four: sustainable security and reliability of supplies. The GDNs have demonstrated that they face several long term challenges that could be addressed though an IFI mechanism. Given the nature and similarities

[24] Regulatory Impact Assessment for Registered Power Zones and the Innovation Funding Incentive
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR4/Documents1/6596-RPZ%20IFI%20RIA%20Final.pdf

[25] MM/BPI – Innovation in Electricity Distribution Networks, March 2004
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR4/Documents1/6763-6204_mottsreport.pdf

of the DNOs' and GDNs' businesses it is reasonable to conclude that the returns will be comparable.

1.60. It may also be possible for the GDNs and other network utilities to collaborate in the future, for example trenching techniques or the reinstatement of excavated material.

Table A12.3 - DNO IFI costs versus expected benefits for 2006-07

Company	Eligible Costs (£k)	Cost / Project £k / project	Intensity (RD&D as % of turnover)	Internal Expenditure (£k)	Forecast Benefits NPV (£k)	Internal expenditure as % of total
CE Group	669	45	0.16%	100	2,341	15%
CN Group	1,114	36	0.20%	160	2,657	14%
EDF Energy Group	3,580	108	0.45%	390	21,700	11%
SP Group	1,269	31	0.24%	174	6,582	14%
S&S Group	1,018	36	0.19%	136	1,683	13%
UU	1,298	41	0.51%	273	10,271	21%
WPD Group	224	25	0.06%	32	518	14%
All DNOs	9,173	49	0.27%	1,266	46	15%

Source: IFI annual reports for DNOs 2006/7

Conclusions

1.61. Current RD&D investment is at a low level and it is likely that, without change to the regulatory environment, companies will continue in this pattern.

1.62. We conclude that the potential value to be derived through innovation is likely to considerably exceed the cost, and on balance we consider that IFI/SD has the potential to deliver benefits to consumers over the price control period and into the longer term. It therefore provides appropriate justification to proceed with the IFI/SD for gas distribution.

1.63. The cost to consumers of the IFI is modest in the overall context of the price control. Mechanisms are proposed to ensure that there is visibility of innovation activities and that consumers gain an appropriate share of the benefits that flow from IFI funded RD&D.

Appendix 13 - Impact Assessment for Environmental Emissions Proposal

Objectives

1.1. The objective of this impact assessment is to consider the merits of introducing an environmental emissions incentive to further incentivise the reduction in environmentally harmful emissions from the gas distribution networks.

Background

1.2. Section 10 of the Utilities Act 2000 places a duty on the Authority to have regard to guidance[26] published by the Secretary of State relating to social and environmental matters. This guidance includes the aim of reducing greenhouse gas emissions and suggests that the Authority considers environmental impact beyond climate change, citing air quality as an example.

1.3. Natural gas emissions contribute to global warming and have an adverse impact on air quality.

1.4. Shrinkage gas is gas lost from the distribution system due to leakage, theft and gas used for operational purposes. It is currently around 0.65 per cent of annual distribution network throughput, of which some 95 per cent relates to leakage.

1.5. Shrinkage gas costs constitute a portion of the revenue allowance under the one year price control. The shrinkage portion of the allowance is based on an ex ante target shrinkage volume with the reference cost of gas based on the prevailing market price. This protects GDNs from price risk due to changes in the wholesale price of gas but, at the same time, provides an incentive for GDNs to reduce costs by decreasing shrinkage volumes (including leakage) and purchasing gas efficiently. We propose to retain the current shrinkage incentive for the future price control but recognise that its strength is related to the economic cost of shrinkage and does not explicitly take account of the environmental impact of gas leakage. We propose introducing a further incentive to reduce gas leakage from the GDNs by exposing them to the social cost of the emissions to better take into account the environmental impact.

1.6. The proposed leakage incentive will set an ex ante baseline for gas leakage for each LDZ for the five year price control period. The baseline will reflect the amount of greenhouse gas leakage that would be expected if this incentive was not introduced.

[26] Social and Environmental Guidance to the Gas and Electricity Markets Authority 24th February 2004

1.7. If the GDNs are able to reduce shrinkage below the baseline they will earn additional revenue that is broadly equivalent to the social benefit of the reduction in environmental emissions. Conversely, if the LDZ emissions are above the baseline, the revenue allowance for that LDZ will be reduced by the social cost of the environmental emissions above the baseline. This will provide an additional economic incentive for the GDNs to reduce greenhouse gas emissions and will provide additional revenue to facilitate additional investment in reducing environmental emissions.

1.8. We propose to introduce cap and collar arrangements to prevent unintended risks of inappropriate payments should the outcome of the new incentive differ substantially from our expectations.

1.9. This impact assessment evaluates the costs and benefits associated with introducing the incentive, including ancillary impacts, where possible in a quantitative manner.

Key issues

1.10. Leakage of natural gas from distribution networks contributes to global warming and to air pollution. We need to consider whether it is appropriate for Ofgem to introduce a new incentive exposing the companies to the environmental costs of emissions.

1.11. The gas distribution companies are currently exposed to procurement costs of gas emitted from their networks but not to the full environmental costs of emissions. A key issue for this incentive is determining the appropriate level of environmental costs used in setting the strength of the incentive.

1.12. Different baselines will have a significant influence on the financial outcome for the companies and a key issue will be setting baselines at an appropriate level to avoid the companies being exposed to windfall gains or losses.

1.13. Gas emissions cannot be measured directly and we estimate leakage from an engineering computer model. The robustness of the leakage model and input data to the model are important issues to be considered.

1.14. The proposed incentive raises the issue of periodicity, particularly where capex is considered. 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 significantly higher allowed revenue than if spent at the end of the period. We are minded not to introduce a rolling incentive allowing the companies to benefit from five years of revenue allowances from the environmental incentive irrespective of when the investment is made because of the complexity, interaction with other incentives and the difficultly in establishing an appropriate mechanism.

1.15. Reducing environmental emissions will not be achieved without incurring costs. We anticipate that increased revenue allowances will result in price increases which will affect all customers proportionately. We anticipate that introducing this incentive will increase average distribution charges by between 0.04 per cent and 0.08 per cent.

Options

Strength of incentive

1.16. Defra recently published interim guidance on valuing greenhouse gas emissions[27]. This guidance introduces a Shadow Price of Carbon (SPC), which is stated in equivalent tonnes of CO2 emissions as £25.40 in 2007 terms, increasing in real terms by 2 per cent per annum.

1.17. In 2005-06 prices, this equates to an average of £93 per tonne of carbon over the price control period, which is approximately £416 per tonne of natural gas leakage, 87 pence per therm or £29,653 per GWh. According to data published by the Joint Office, leakage from the distribution networks during the gas year 2006 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.

1.18. On 17 July 2007, Defra published the Government's air quality strategy[28], 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.

1.19. We recognise that natural gas emissions also affect air quality. 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 seriously damages our ecosystems. Such factors reinforce the introduction of a leakage incentive but do not justify a stronger incentive than that based on global warming potential.

Baseline volume & financial exposure

1.20. The GDNs will be exposed to an increase or decrease in allowed revenue based on the difference between reported actual leakage and the incentive baselines.

1.21. Varying the level of the incentive's baseline will not change the incentive on the company to reduce emissions. The level of reduction will be determined by the companies' response to the strength of the incentive and the actual costs of reducing emissions. Different baselines will have a significant influence on the financial

[27] http:// www.defra.gov.uk/environment/clinatechange/research/carboncost/index.htm
28 http://www.defra.gov.uk/environment/airquality/strategy/index.htm

outcome for the companies and a key issue will be setting baselines at an appropriate level to avoid the companies being exposed to windfall gains or losses.

1.22. The GDNs' submissions suggest that leakage will be further reduced by around 1.5 per cent due to the introduction of this incentive with capital expenditure of around £30 million. We would anticipate some out-performance in the GDNs' estimates and consider that reductions in the range of 2 per cent to 4 per cent achievable.

1.23. Assuming the companies are able to reduce emissions by 2 per cent to 4 per cent below the target baseline, the increase in allowed revenue will be £2.4 million to £4.8 million per annum, which is equal to the shadow cost of the emissions eliminated.

1.24. We propose to set baselines for each network consistent with our forecast level of leakage in the absence of this incentive. Some GDNs forecast increasing leakage over the price control period even though old metallic pipes are being replaced with PE and average system pressures were not forecast to rise. Following discussion, the GDNs submitted supplementary information on forecast leakage. We have based our forecasts on historic leakage submitted in the BPQ responses and assumed that this would trend downwards at the rate shown by the GDNs in the supplementary responses.

Gas Composition

1.25. The composition of natural gas varies considerably depending on its source, for example, gas from LNG terminals tends to have lower levels of methane than gas from some UKCS gas fields. The GDNs have no effective influence on the composition of natural gas in their networks. If we set the incentive based on actual tonnes of each gas component emitted this would expose the GDNs to significant windfall gains or losses as the composition of the gas supplied from the NTS varies.

1.26. Ignoring the effect of variations in composition would not change the behaviour of the GDNs in reducing leakage although they would be responding to an incentive based on reducing natural gas leakage rather than the amounts of individual gases contained in natural gas. This would in theory introduce inaccuracies in the link between the reduction in social cost of emissions and the incentive. However, it should be noted that evaluating the social cost is subject to significant uncertainty.

1.27. Assuming a constant gas composition considerably simplifies reporting and monitoring, while providing virtually identical incentive properties.

1.28. We propose assuming a constant gas composition and setting the incentive on natural gas leakage as a proxy for greenhouse gas leakage.

Competition assessment

1.29. None of the options we are considering are likely to have any impact on competition in the wholesale or retail supply markets.

Impacts, costs and benefits

Environment

1.30. We anticipate that introducing the incentive will lead to a reduction in gas emissions with commensurate environmental improvements. Reduced natural gas leakage will reduce greenhouse gas emissions and lead to air quality improvements.

1.31. We anticipate that environmental benefits will be greater as the strength of the incentive is increased. While the level of baselines selected will have a significant impact on allowed revenue, we do not believe that different baselines will materially change the response of the companies to the incentive as the efficient marginal response remains unchanged.

Security of supply

1.32. We anticipate no material impact on security of supply.

Health and safety issues

1.33. The existing mains replacement incentive policy contributed to reducing shrinkage volumes as it results in the replacement of older metallic pipes with new polyethylene pipes which have lower rates of leakage.

1.34. The introduction of an environmental emissions incentive will increase the focus of the GDNs' management on leakage reduction and is expected to increase the amount of money that will be spent on reducing leakage. This in turn should lead to an increased rate of leakage reduction. The new incentive will provide additional focus on pipes that are not subject to the mains replacement incentive and we expect some of these to be replaced earlier than would have been in the absence of this incentive.

1.35. We anticipate that the average pressure of gas in the networks will be lower as a result of this incentive than the average pressure without the incentive, particularly in areas of predominantly metallic pipe, which will in turn reduce leakage quantities. Lower pressures could, arguably, appear to result in reduced asset utilisation and capital efficiency. We anticipate that pressure reduction will largely stem from improved pressure control in existing networks, where there is no efficiency loss, but we are aware that there may be some marginal changes to network design leading to replacement pipes being larger than would otherwise be the case. The overall incentive package faced by the companies will align their rewards with the most efficient means of reducing leakage.

1.36. Further reducing the quantity of gas leakage is expected to improve safety by reducing the risk of explosions and alleviate health concerns that indirectly result from leakage through the pollutants emitted.

Distributional effects

1.37. Distributional effects between different consumer groups should not arise as a result of implementing the proposed incentive.

Small businesses

1.38. Small businesses are not expected to be affected differently from customers in general.

Risks and unintended consequences

1.39. The most significant risk relates to setting appropriate leakage baselines. Should baselines be set too high the companies will receive windfall gains and conversely if set too low the companies will be subject to windfall losses.

1.40. In initial proposals, we raised concerns about the operation of the leakage model and the robustness of input data into the model. We have since discussed the operation of the leakage model with the GDNs and are satisfied, although the model's uncertainty range is around +/-20 per cent, that the model is satisfactory for the purposes of setting a leakage incentive. We are considering introducing revised governance arrangements to mitigate unintended consequences due to operation of the leakage model and are considering process audits to help to ensure the robustness of the input data.

Costs and benefits

1.41. The total shadow cost of greenhouse gas emissions from the gas distribution networks is currently estimated to be £118 million per annum. The emissions also contribute to air pollution.

1.42. As discussed above, we expect allowed revenue and hence distribution charges to increase by between £2.4 to 4.8 million as the GDNs are expected to increase expenditure on leakage reduction and thus outperform the leakage baseline. This revenue allowance, used to fund the costs of leakage reduction, will ultimately be paid for by consumers.

1.43. In initial proposals we stated that maximum total revenue allowances for the coming period average £2,368 million per annum. The suggested range of increased revenue allowances would result in an average increase in distribution transportation maximum allowed revenue of 0.04 per cent to 0.08 per cent.

1.44. We anticipate that the incentive will incrementally reduce natural gas emissions by between 2 per cent to 4 per cent, which is equivalent to a reduction in the social cost of emissions of between £2.4 to £4.8 million, reducing both greenhouse gas emissions and air pollution.

1.45. The reduction of gas leaking from the networks will also reduce the amount of gas the companies need to purchase under the existing shrinkage arrangements, partially offsetting the cost of the environmental incentive. Assuming a gas cost of 50 pence per therm results in a reduction in shrinkage costs of between £1.4 million and £2.7 million per annum. Under the proposed arrangements these savings accrue to the GDNs until the next price control review. We consider this to be appropriate but we will further consider whether the strength of the environmental incentive should be reduced to take into account the savings in shrinkage gas purchase costs.

1.46. If the GDNs efficiently invest incremental capex to reduce leakage during the 2008 to 2013 period, this would be subject to the proposed capex incentives and is expected to marginally increase allowed revenue during the price control period commencing in 2013. However, this would be offset by further reductions in environmentally harmful emissions and reduced procurement costs for shrinkage gas. We have analysed the benefits of reduced emissions together with savings in procurement costs of shrinkage gas and the analysis indicates that any investment that provides a positive NPV to the GDNs under the proposed environmental and IQI incentive schemes also provides positive benefits to consumers.

Conclusions

1.47. Quantitative analysis shows that customers may pay additional costs which would equal the shadow cost of carbon emissions during the next price control. We are considering introducing cap and collar arrangements to prevent unintended risks due to unforeseen circumstances. There may be some increase in allowed revenue for the following period, due to incremental capex expenditure, but this will be offset by continuing reductions in environmental emissions and anticipated savings in the allowed revenue for procurement of shrinkage gas. Analysis of prices in the future period is highly sensitive to assumptions but based on our projections all efficient investment made by the GDNs will provide positive benefits to consumers.

1.48. Qualitatively, we consider that the introduction of this incentive will bring proportionate environmental benefits and that these benefits outweigh the relatively minor potential increase in transportation charges.

1.49. The design of the incentive internalises the shadow cost of carbon to the GDNs. This is expected to influence management decisions and provide a more appropriate framework for the companies to judge investment decisions that have environmental impacts.

1.50. In the longer term, customers are expected to benefit from reductions in the quantity of shrinkage gas procured as leakage is reduced prior to setting shrinkage allowance for the price control starting in 2013.

1.51. We anticipate that transportation bills will increase as the GDNs are expected to increase expenditure on leakage reduction and thus outperform the leakage baseline. This incremental revenue allowance, used to fund the costs of leakage reduction, will ultimately be paid for by consumers.

1.52. We propose that the strength of the incentive should be set in line with the governments published shadow price of carbon and that it should be set ex ante for the duration of the price control.

1.53. We propose introducing revised governance arrangements to ensure robust operation of the leakage model.

Appendix 14 - Shrinkage arrangements and Environmental Emissions

General Background

1.1. For the one year control Ofgem set allowed revenue based on an ex ante shrinkage factors and a gas price formula linking allowed revenue to three month-ahead gas prices over the period of the control. The GDNs are financially exposed to the difference between the revenue allowance and the cost of the shrinkage gas they actually procure. Linking the allowed revenue to forward gas prices reduces the GDNs' exposure to gas price changes over the price control period when compared to an ex ante fixed price.

1.2. The UNC determines the quantity of shrinkage gas procured by GDNs. The method employed to calculate the quantity of gas procured by the GDNs is based on estimates of leakage from the distribution network, use of gas by specific types of plant within the network and theft. These estimates were developed by Transco during a national leakage survey in 2002-03. The GDNs assess the amount of each type of plant in each LDZ and apply pre-determined factors to calculate shrinkage from the LDZ. The quantity of shrinkage gas to be procured by the GDNs is estimated prior to the gas year and reviewed ex post. Any inaccuracy between the amount of gas procured by GDNs and that actually leaked from or consumed by the GDNs is charged or credited to non-daily metered shippers via the RBD process.

Shrinkage Incentive

Determination of the volume of shrinkage gas

1.3. In the one year control, volume allowances for theft of gas and for own use gas were set as a proportion of demand. We have no information to suggest that this is inappropriate. Volume allowances for leakage were also set as a proportion of demand. We have analysed the relationship between leakage and demand using data provided by the GDNs. The data are illustrated in figures A14.1 to A14.4 below, together with linear trend lines and their associated equations. While the results show that for any fixed network, more leakage takes place from a big network than a small one, there is no clear correlation between leakage and variation in demand for any given network and in some networks leakage appears to decrease with higher demand. This does not appear to justify continuing to link the volume allowance to demand.

Figure A14.1 - Relationship between leakage and demand in NGG's networks

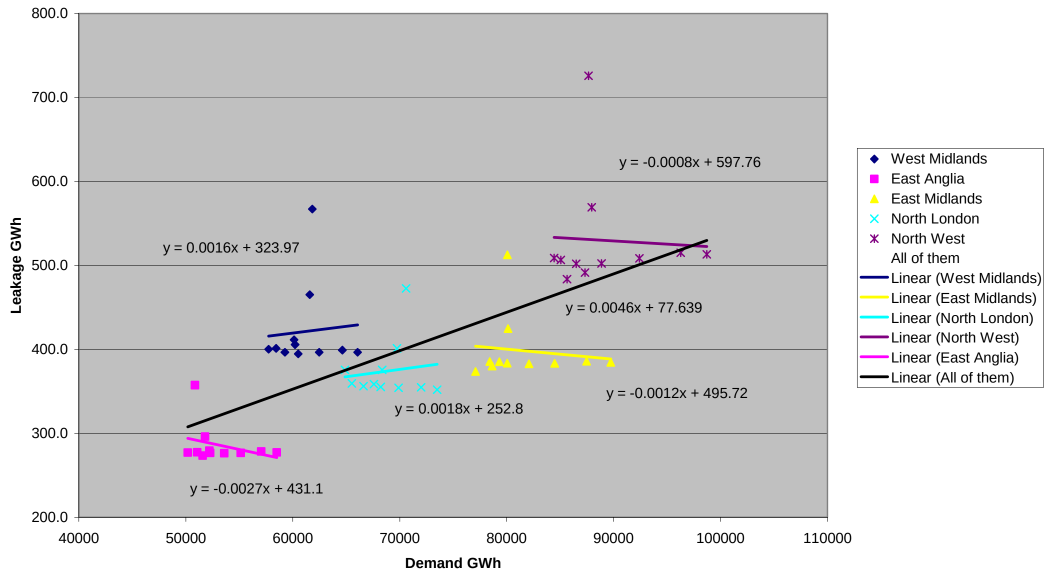


Figure A14.2 - Relationship between leakage and demand in NGN's networks

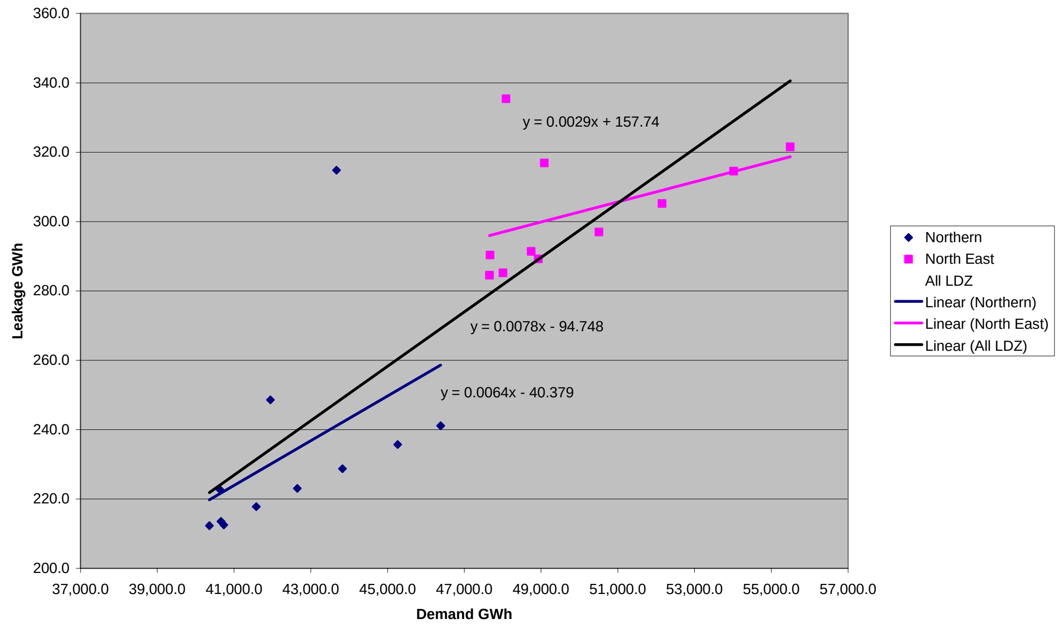


Figure A14.3 - Relationship between leakage and demand in SGN's networks

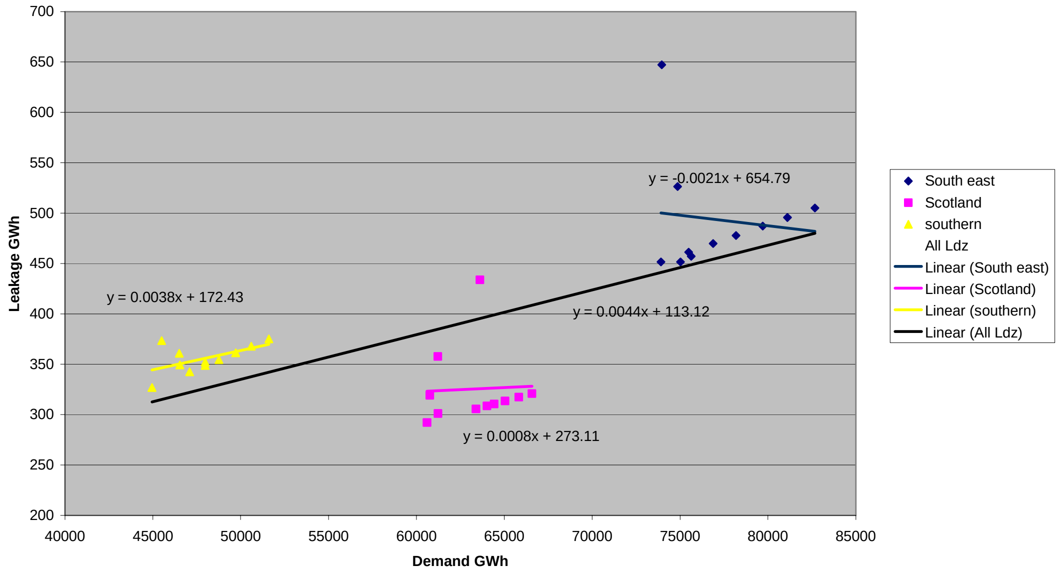
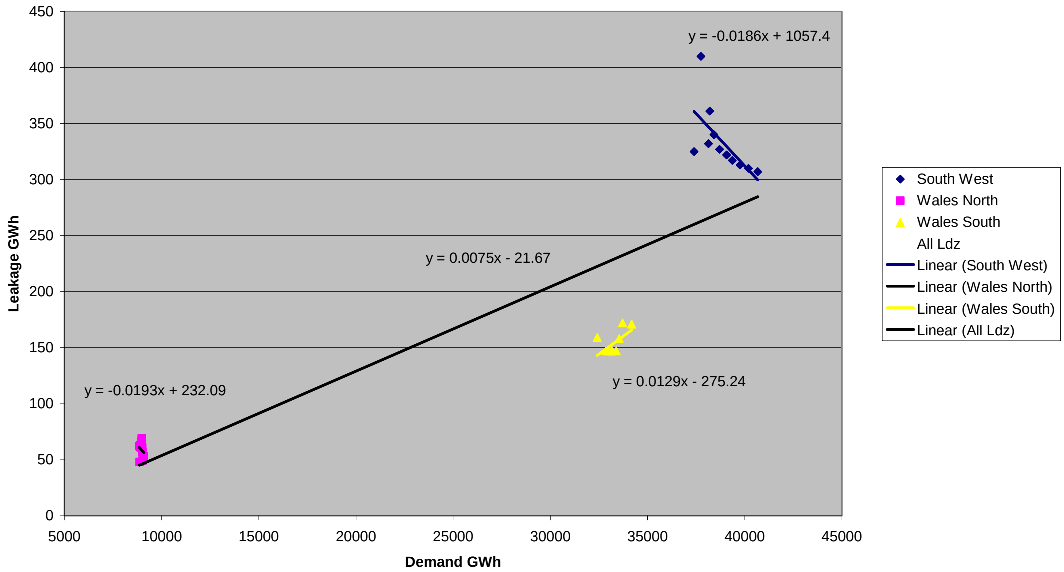


Figure A14.4 - Relationship between leakage and demand in WWU's networks



1.4. The GDNs consider that further analysis would be needed to establish a more robust relationship between leakage and demand. The GDNs provided historical and forecast shrinkage data, which were broadly accepted by our consultants.

1.5. Some of the GDNs forecast that shrinkage factors would remain constant in spite of leaking metallic pipes being replaced with PE pipes, which leak less, with the average system pressure forecast to remain constant. This resulted in an increase in forecast leakage as demand increased.

1.6. Some of the GDNs forecast that shrinkage factors would remain constant but that average system pressure would rise. This resulted in an increase in forecast leakage.

1.7. We accept that mains replacement may result in increasing system pressure and that this may be an efficient consequence of the mains replacement programme. We expect the more significant increases in system pressure to occur generally in areas which have experienced a larger degree of replacement and thus having pipes with a lower propensity for leakage. Historical analysis suggests that the mains replacement programme has to date resulted in decreasing levels of leakage and we expect this trend to continue.

1.8. We considered that there were some issues with the GDNs' forecast in this area and therefore requested supplementary data from them on leakage.

1.9. The supplementary data, although qualified by the GDNs, confirmed that the trend of leakage would continue to reduce throughout the next period. We have therefore adjusted the GDN's forecasts using historical data from the original BPQ submissions as the starting position and used the downward trend shown in the GDN's supplementary responses to provide an adjusted baseline for each LDZ. We have also considered the glidepaths to the levels of leakage anticipated following completion of the mains replacement programme and found the adjustments to be broadly consistent with these glidepaths.

1.10. We have taken into account the GDNs forecasts, our consultant's views and our own analysis and propose establishing leakage baselines as illustrated in the figures A14.5 to A14.9.

1.11. We have labelled the charts for the East Anglia LDZ:

- EA (BPQ), the original BPQ submission;
- EA (Update), the GDN's updated response;
- Adj EA, our adjusted forecast of leakage; and
- other charts are similarly labelled for the other LDZs.

1.12. For SGN we did not have a full breakdown for all LDZs and in some cases we have apportioned total network figures between their LDZs.

Figure A14.5 - Leakage in NGG's EA, EM and NW LDZs

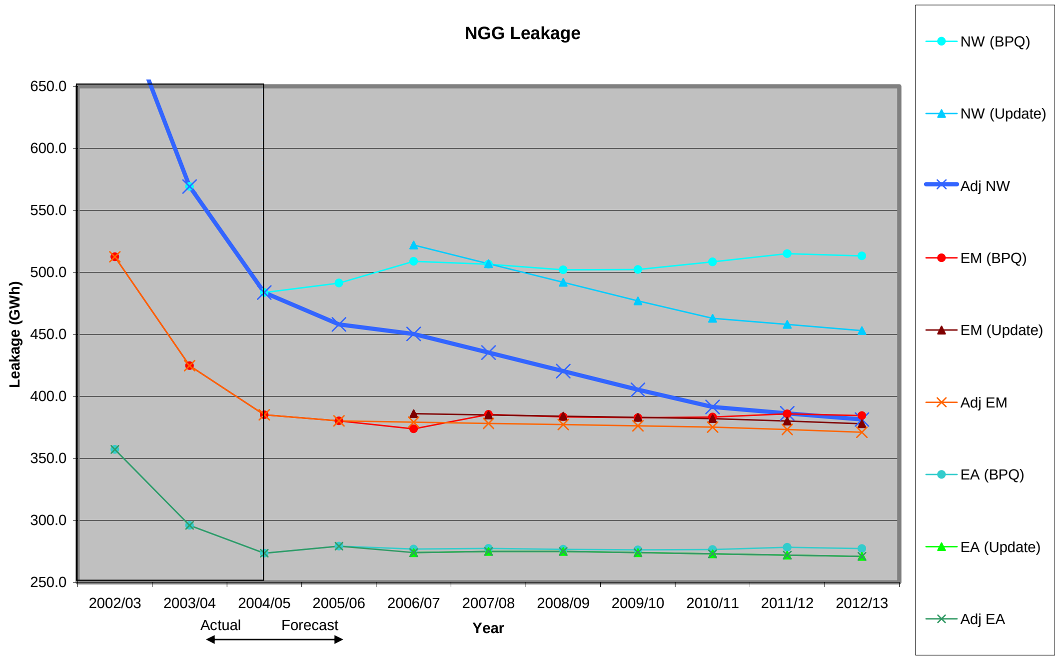


Figure A14.6 - Leakage in NGG's NL and WM LDZs

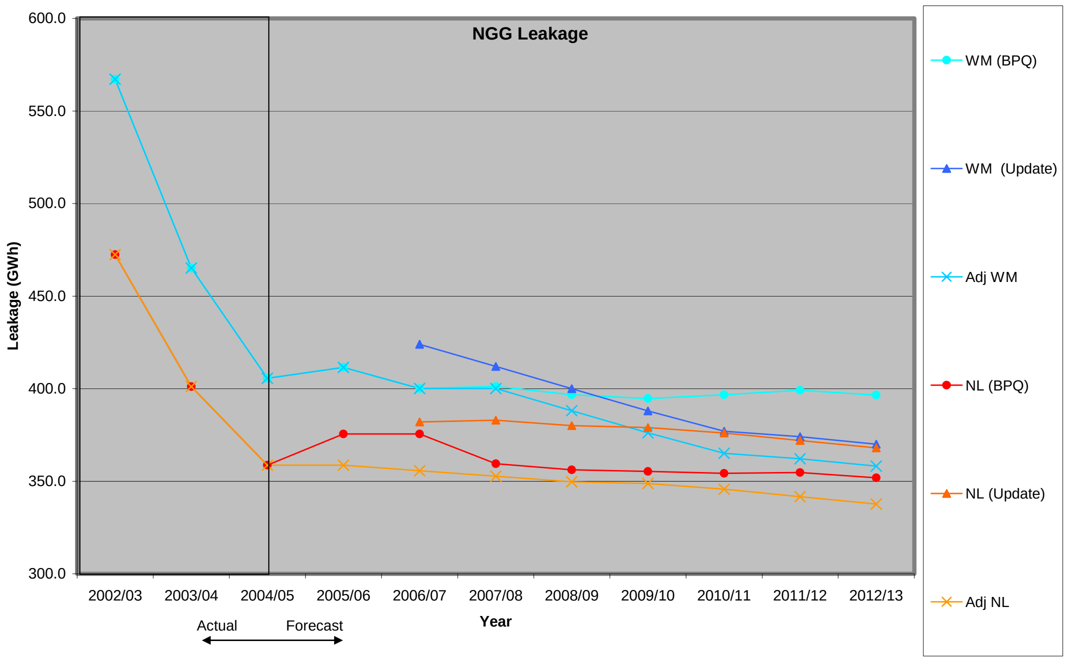


Figure A14.7 - Leakage in NGN's LDZs

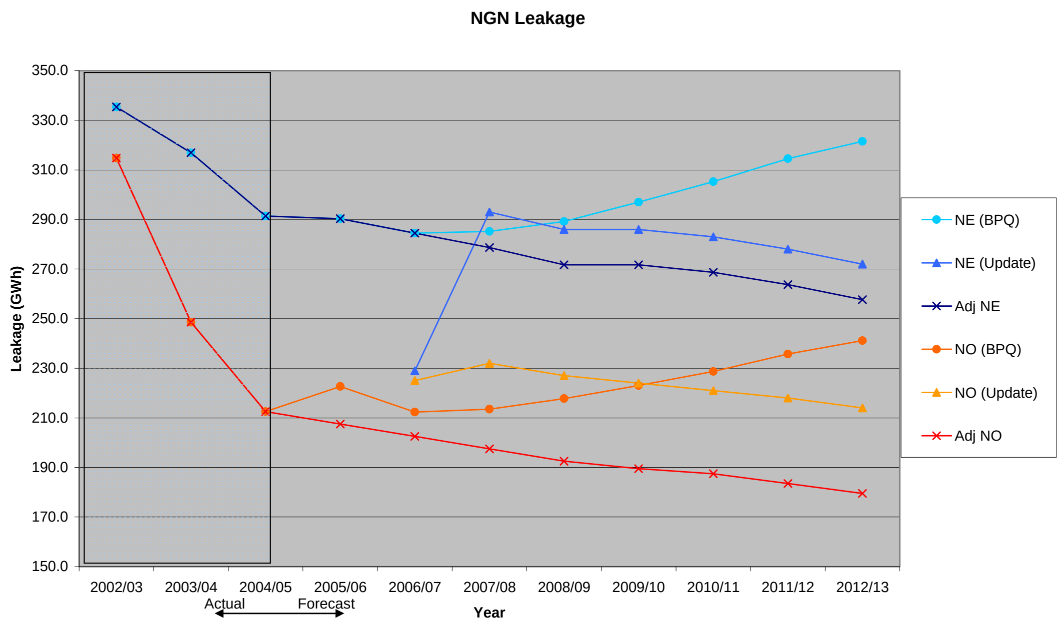
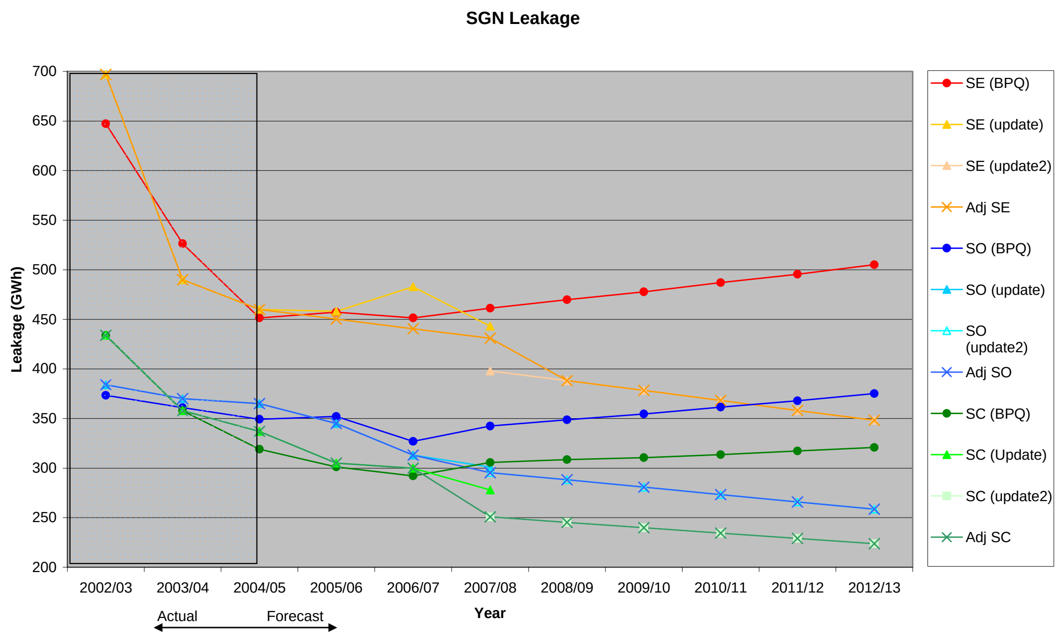
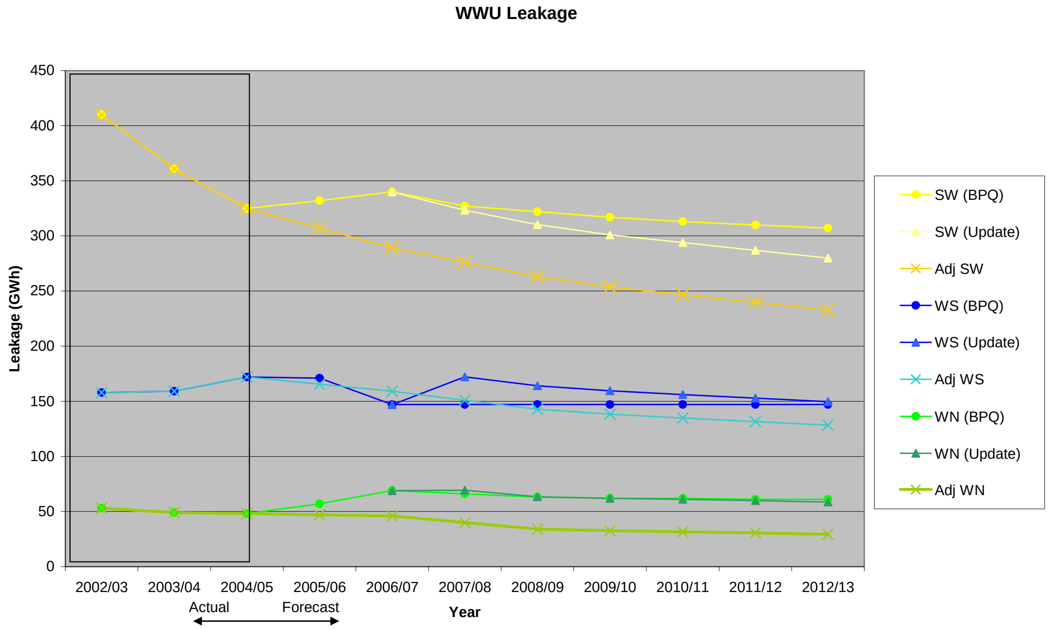


Figure A14.8 - Leakage in SGN's LDZs[29]



[29] Please note that some of the lines in this figure may not be visible as they coincide with other lines. For example, the SO (update) line cannot be seen as it overlaps with the Adj SO line.

Figure A14.9 - Leakage in WWU's LDZs



Determination of gas reference price for the shrinkage incentive

1.13. We consider it appropriate that the gas reference price used to determine the revenue allowance broadly reflects the price an efficient company would pay to procure the gas without exposing the GDN's to significant price risk. For the one year rollover the reference price was calculated as a 3.5 percent uplift over the daily Heren three month-ahead forward offer price. One respondent did not support using an uplift factor and did not support removal of all shrinkage price risk from the GDNs. Another respondent considered that it was efficient to procure gas in the spot market and argued that the reference price should be the actual price on the day the gas was consumed. One GDN considered that the current 3.5 per cent uplift was inadequate.

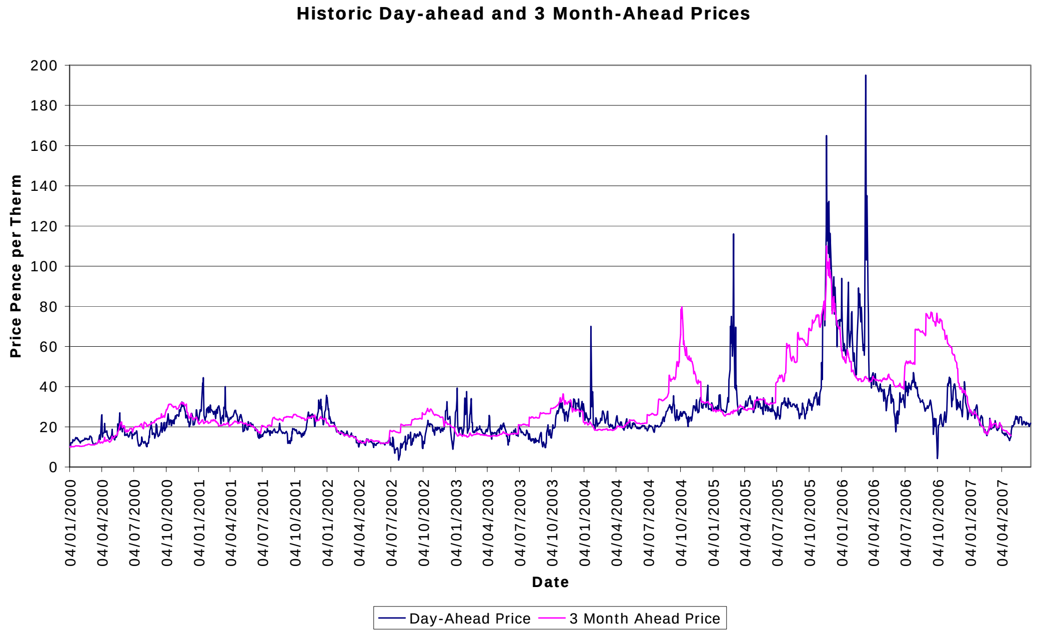
1.14. A number of GDNs provided analysis showing that end of day price or within day prices would have resulted in lower total cost than procuring three months ahead.

1.15. In the one year final proposals paper we stated that we would consider additional information on medium term trends in gas index prices and actual purchase costs. Historical analysis indicates that if the reference price had been based on three month-ahead forward offer prices with the 3.5 per cent uplift it would have been some 6 per cent higher than if the reference price had been based on day-ahead[30] prices.

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

1.16. Use of day-ahead prices would eliminate the inherent price asymmetry due to forecasting errors (if shrinkage gas requirements are higher than forecast, this is usually because demand is higher and so spot prices are usually higher than the forward price. Conversely where shrinkage gas requirements are lower than forecast, the spot price is lower, meaning that the GDN is selling back to the market at a loss).

Figure A14.10 - Historical gas prices



1.17. We propose setting the gas reference price for calculating allowed revenue as the on the day or day-ahead price.

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

1.19. The GDNs will continue to be exposed to the difference between the revenue allowance and the cost of shrinkage gas they actually procure; thus providing an incentive to reduce shrinkage volumes and procurement costs.

Environmental emissions incentive

Background

1.20. In initial proposals we additionally considered strengthening the financial incentives on shrinkage to reflect the environmental costs of gas leakage.

1.21. We propose setting a baseline level of gas emissions, with the companies exposed to the environmental cost of emissions above or below the baseline. We propose that the incentive strength is linked to the Government's published shadow cost of carbon emissions and qualitatively takes into account the cost of air quality pollution.

1.22. The government's published shadow price of carbon is approximately equivalent to £29.6/MWh of gas leakage.

Proposed incentive design

1.23. We propose setting an ex ante baseline for greenhouse gas leakage for each LDZ for the five year GDPCR period. We propose that the baseline will reflect the anticipated amount of greenhouse gas leakage from each LDZ.

1.24. If the GDNs are able to reduce shrinkage below the baseline they will earn additional revenue that is broadly equivalent to the social benefit of the reduction in greenhouse gas emissions. Conversely, if the LDZ emissions are above the baseline, the revenue allowance for that LDZ will be reduced by the shadow cost of carbon above the baseline.

1.25. This will provide an incentive for the GDNs to reduce greenhouse gas emissions and will provide additional revenue to allow specific investment in greenhouse gas reduction projects.

1.26. The GDNs suggested that it would be appropriate to introduce a rolling incentive such that the companies receive ongoing rewards for improvements made in the latter years of the control. 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.

1.27. We propose establishing caps and collars to prevent unforeseen windfall gains and losses.

Determination of greenhouse gas baseline

1.28. We propose setting baselines for greenhouse gas volumes based on the expected leakage in the absence of an environmental incentive. We consider that it is appropriate for the baseline to reflect gas leakage rather than total shrinkage, which includes own use gas and theft components. We propose setting leakage baselines identical to the leakage components of the shrinkage incentive discussed above.

1.29. The GDNs have very little influence on the composition of gas entering the LDZ networks. Basing the incentive on 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 therefore propose using a constant gas composition and set 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.

Determination of the strength of the environmental emissions incentive

1.30. Defra recently published interim guidance on valuing greenhouse gas emissions[31]. This guidance introduces a "Shadow Price of Carbon", which is stated in equivalent tonnes of carbon dioxide (CO2) emissions as £25.40 per tonne in 2007 prices, increasing in real terms by 2 per cent per annum.

1.31. Natural gas comprises a number of different gases including the greenhouse gases methane and carbon dioxide. We have used the average composition for 2006 to calculate the equivalent shadow price of carbon for natural gas emissions.

1.32. 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 £29653 per GWh. 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.

Reporting

1.33. 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.

1.34. Methane leakage is separately reported under standard special licence condition D9 (RIGs). GDNs currently report shrinkage levels to Ofgem as part of the GDPCR process and report to shippers under UNC. Reporting is based on the shrinkage model discussed below. This model apportions a significant amount of money between the GDNs and shippers.

1.35. 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.

Shrinkage Model

1.36. In initial proposals document 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 the governance arrangements surrounding its

31 http://www.defra.gov.uk/environment/climatechange/research/carboncost/index.htm

collection and changes to the model. We have held meetings with the GDNs and received supplementary information about the model.

1.37. 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 and for theft. It is possible to remove items related to own use gas and theft of gas such that gas leakage is reported as a separate sub set of shrinkage. We consider that this subset provides an appropriate measure of leakage for this incentive.

1.38. The current shrinkage model based on a national leakage survey performed in 2002-03. Academics and consultants were involved in selecting test samples, auditing the results, assessing their uncertainty and validating their statistical significance. The work was performed by consultants appointed by Transco, who made all the results and associated reports available to Ofgem and the industry during an open and transparent process. Ofgem representatives participated in this process. The 90 per cent confidence interval of the overall leakage test results was +/19.4 per cent.

1.39. The shrinkage model is currently utilised to determine the quantity of shrinkage gas paid for by the GDNs and the amount paid for by non-domestic shippers and a variation of it is used to report environmental leakage to Ofgem and other government agencies. The model apportions a significant amount of money between the GDNs and shippers and therefore has considerable financial significance. Although we have some concerns about minor issues such as the amount of theft, our current view is that the current model is sufficiently robust for the purposes of setting allowed revenue for the greenhouse gas incentive.

1.40. Input data includes items such as the length of each type of pipe within the network, network operating pressures, the use of operational leakage mitigation tools (i.e. fogging with mono ethylene glycol), the quantity of each type of AGI plant, data on leaks following damage and other information about the network and its operation.

1.41. It would be possible to augment the current leakage model by performing additional leakage tests and performing further studies. We must however consider the cost of such work given the relatively limited scope for improvement in model accuracy. Having a more accurate model is unlikely to affect the incentive properties of the proposed greenhouse gas incentive. Comparison of the 2002-03 leakage results with results of the 1992 national leakage survey indicates significant differences. We considered whether it was appropriate to initiate an ongoing or periodic survey with the aim of reducing the confidence interval. We discussed this with the GDNs who pointed out that the cost of performing sufficient tests to significantly improve the uncertainty in the model would be disproportionate to the benefits.

1.42. 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 inadequacy of the model. 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. We propose incorporating a description of the model either in a licence condition or a document referenced in the licence that can only be changed if a change is formally requested by a GDN and subsequently approved by the Authority if it considers this to be in the interest of consumers.

1.43. We note the possibility that the GDNs could reduce leakage by disposal of assets and if necessary we would take this into account by adjusting the incentive baselines prior to approving such a disposal.

Data validation

1.44. Under the present arrangements forecast shrinkage volumes are determined ex ante during the price control process. 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.

1.45. GDNs currently report shrinkage levels to Ofgem as part of the GDPCR process and report to shippers under UNC. Reporting is based on the shrinkage model discussed above. This model apportions a significant amount of money between the GDNs and shippers.

1.46. As noted above we intend to specify the operation of the model used to calculate leakage in a document governed under the licence.

1.47. 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 will consider initiating periodic independent audits or reviews should we consider this appropriate.

1.48. During the early years of implementing the new incentive we consider that there would be value in performing a process audit and sharing the results across the GDN companies and we will consider this at a later date.

Appendix 15 - Mains and services cost matrices

National Grid Gas - East England

Table A15.1 - Services replacement matrix for 2008-9 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	33,046	463.5	15.3	36,566	455.1	16.6
services transferred	33,046	285.3	9.4	36,566	279.3	10.2
non domestic services	36	1,560.6	0.1	38	1,529.8	0.1
Total	**66,128**		**24.8**	**73,169**		**26.9**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	36,422	453.3	16.5	34,848	450.9	15.7
services transferred	36,422	278.3	10.1	34,848	277.1	9.7
non domestic services	36	1,514.3	0.1	39	1,510.2	0.1
Total	**72,881**		**26.7**	**69,735**		**25.4**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	35,283	448.7	15.8			
services transferred	35,283	275.7	9.7			
non domestic services	41	1,501.4	0.1			
Total	**70,607**		**25.6**			

Table A15.2 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	35	61.9	2.2	38	61.1	2.3
4-5"	382	67.5	25.8	407	66.7	27.1
6-7"	98	95.0	9.3	139	93.9	13.0
8-9"	50	175.8	8.8	42	173.7	7.2
10-12"	40	245.6	9.9	43	242.6	10.5
>12-18"	12	356.1	4.2	13	351.9	4.7
>18-24"	7	497.8	3.3	8	491.8	4.2
>24"	1	614.3	0.4	2	606.9	1.0
Total	**625**		**63.9**	**692**		**70.1**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	29	60.7	1.8	29	59.6	1.7
4-5"	409	66.2	27.1	369	65.0	24.0
6-7"	130	93.2	12.1	119	91.5	10.9
8-9"	53	172.4	9.1	59	169.3	10.0
10-12"	49	240.8	11.8	54	236.5	12.7
>12-18"	11	349.2	4.0	23	342.9	7.9
>18-24"	8	488.1	3.7	13	479.3	6.1
>24"	2	602.4	1.3	4	591.5	2.1
Total	**691**		**70.8**	**669**		**75.4**
	2012-13					
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**			
</=3"	28	59.2	1.6			
4-5"	391	64.7	25.3			
6-7"	116	91.0	10.5			
8-9"	50	168.3	8.4			
10-12"	52	235.1	12.1			
>12-18"	28	340.9	9.6			
>18-24"	14	476.5	6.9			
>24"	3	588.0	1.5			
Total	**681**		**76.0**			

National Grid Gas - London

Table A15.3 - Services replacement matrix for 2008-9 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	21,474	564.2	12.1	18,372	571.8	10.5
services transferred	15,745	337.2	5.3	13,511	342.1	4.6
non domestic services	165	1,981.5	0.3	69	2,002.1	0.1
Total	**37,384**		**17.8**	**31,952**		**15.3**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	19,265	567.8	10.9	21,002	565.0	11.9
services transferred	14,185	339.6	4.8	15,494	337.9	5.2
non domestic services	144	1,994.3	0.3	231	1,985.8	0.5
Total	**33,593**		**16.0**	**36,727**		**17.6**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	20,311	567.0	11.5			
services transferred	14,971	339.1	5.1			
non domestic services	156	1,995.1	0.3			
Total	**35,438**		**16.9**			

Table A15.4 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	22	75.9	1.7	20	76.5	1.6
4-5"	159	82.8	13.1	150	83.6	12.5
6-7"	70	116.5	8.1	48	117.6	5.6
8-9"	33	215.6	7.1	25	217.5	5.5
10-12"	39	301.2	11.6	37	303.9	11.1
>12-18"	29	436.7	12.7	25	440.6	11.0
>18-24"	12	610.4	7.4	10	615.9	6.5
>24"	17	753.3	12.8	15	760.0	11.3
Total	**380**		**74.6**	**330**		**65.1**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	21	77.0	1.6	20	74.3	1.5
4-5"	146	84.0	12.2	155	81.2	12.6
6-7"	67	118.2	7.9	87	114.2	10.0
8-9"	29	218.7	6.4	30	211.3	6.4
10-12"	30	305.6	9.1	30	295.1	8.8
>12-18"	25	443.1	11.3	25	428.0	10.6
>18-24"	12	619.4	7.2	15	598.2	9.2
>24"	15	764.3	11.1	10	738.2	7.2
Total	**344**		**66.8**	**373**		**66.2**
	2012-13					
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**			
</=3"	21	74.6	1.6			
4-5"	148	81.5	12.1			
6-7"	75	114.6	8.6			
8-9"	34	212.0	7.1			
10-12"	33	296.2	9.8			
>12-18"	22	429.6	9.6			
>18-24"	12	600.4	7.3			
>24"	8	741.0	6.2			
Total	**354**		**62.2**			

National Grid Gas - North West

Table A15.5 - Services replacement matrix for 2008-9 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	33,034	447.7	14.8	32,602	446.9	14.6
services transferred	21,904	270.0	5.9	21,614	269.6	5.8
non domestic services	59	1,566.9	0.1	59	1,549.5	0.1
Total	**54,997**		**20.8**	**54,276**		**20.5**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	32,064	446.5	14.3	32,154	444.8	14.3
services transferred	21,256	269.4	5.7	21,315	268.4	5.7
non domestic services	59	1,549.5	0.1	59	1,549.5	0.1
Total	**53,379**		**20.1**	**53,528**		**20.1**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	30,445	446.9	13.6			
services transferred	20,100	269.9	5.4			
non domestic services	59	1,549.5	0.1			
Total	**50,603**		**19.1**			

Table A15.6 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	99	61.5	6.1	98	61.3	6.0
4-5"	248	67.1	16.6	243	67.0	16.3
6-7"	110	94.4	10.4	109	94.2	10.3
8-9"	41	174.6	7.2	40	174.3	6.9
10-12"	35	244.0	8.6	35	243.5	8.6
>12-18"	31	353.8	10.8	32	353.1	11.2
>18-24"	15	494.5	7.2	14	493.5	7.0
>24"	5	610.3	2.8	4	609.1	2.5
Total	**582**		**69.6**	**575**		**68.7**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	90	60.5	5.5	84	60.1	5.0
4-5"	236	66.0	15.6	234	65.6	15.4
6-7"	109	92.9	10.1	108	92.4	10.0
8-9"	54	171.9	9.2	49	170.9	8.3
10-12"	30	240.1	7.1	47	238.7	11.2
>12-18"	28	348.2	9.7	27	346.2	9.4
>18-24"	14	486.6	6.6	11	483.8	5.5
>24"	6	600.6	3.5	5	597.0	2.7
Total	**565**		**67.2**	**564**		**67.5**
	2012-13					
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**			
</=3"	73	59.9	4.3			
4-5"	239	65.3	15.6			
6-7"	91	91.9	8.4			
8-9"	46	170.1	7.8			
10-12"	42	237.6	9.9			
>12-18"	33	344.6	11.3			
>18-24"	9	481.6	4.2			
>24"	3	594.3	1.7			
Total	**535**		**63.2**			

National Grid Gas - West Midlands

Table A15.7 - Services replacement matrix for 2008-9 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	21,056	472.0	9.9	21,250	472.4	10.0
services transferred	20,745	289.1	6.0	20,945	289.3	6.1
non domestic services	115	1,598.8	0.2	115	1,598.8	0.2
Total	**41,916**		**16.1**	**42,310**		**16.3**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	20,857	473.7	9.9	19,832	473.5	9.4
services transferred	20,569	290.3	6.0	19,544	290.5	5.7
non domestic services	115	1,598.8	0.2	115	1,598.8	0.2
Total	**41,540**		**16.0**	**39,491**		**15.3**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	20,255	473.7	9.6			
services transferred	19,967	290.6	5.8			
non domestic services	115	1,598.8	0.2			
Total	**40,336**		**15.6**			

Table A15.8 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	42	61.8	2.6	26	62.3	1.6
4-5"	170	67.5	11.5	180	68.0	12.3
6-7"	76	95.0	7.2	80	95.7	7.6
8-9"	45	175.7	8.0	44	177.1	7.8
10-12"	35	245.5	8.6	44	247.4	10.9
>12-18"	26	356.0	9.1	23	358.7	8.2
>18-24"	14	497.6	7.1	5	501.4	2.6
>24"	2	614.1	1.2	2	618.7	1.1
Total	**410**		**55.3**	**404**		**52.1**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	18	62.3	1.1	19	61.9	1.2
4-5"	195	68.0	13.2	163	67.6	11.0
6-7"	71	95.7	6.8	88	95.1	8.4
8-9"	47	176.9	8.3	38	176.0	6.7
10-12"	35	247.2	8.6	38	245.9	9.3
>12-18"	19	358.5	6.9	22	356.6	7.7
>18-24"	6	501.0	3.1	7	498.4	3.5
>24"	2	618.3	1.0	3	615.0	1.6
Total	**392**		**49.0**	**377**		**49.3**
	2012-13					
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**			
</=3"	25	62.6	1.6			
4-5"	177	68.4	12.1			
6-7"	77	96.2	7.4			
8-9"	46	178.0	8.2			
10-12"	29	248.6	7.1			
>12-18"	19	360.5	6.9			
>18-24"	4	503.9	1.9			
>24"	2	621.8	1.1			
Total	**379**		**46.3**			

Northern Gas Networks - Northern

Table A15.9 - Services replacement matrix for 2008-9 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	27,198	474.7	12.9	27,187	472.1	12.8
services transferred	16,565	289.3	4.8	16,558	287.7	4.8
non domestic services	379	1,620.2	0.6	379	1,612.0	0.6
Total	**44,142**		**18.3**	**44,124**		**18.2**

	2010-11			2011-12		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	27,188	470.0	12.8	27,193	468.4	12.7
services transferred	16,559	286.5	4.7	16,562	285.5	4.7
non domestic services	379	1,603.8	0.6	379	1,598.3	0.6
Total	**44,126**		**18.1**	**44,134**		**18.1**

	2012-13		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	27,190	466.6	12.7
services transferred	16,561	284.4	4.7
non domestic services	379	1,590.2	0.6
Total	**44,130**		**18.0**

Table A15.10 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	89	57.7	5.1	77	56.7	4.4
4-5"	390	63.0	24.5	368	61.9	22.8
6-7"	52	88.7	4.6	72	87.0	6.3
8-9"	15	164.0	2.5	24	161.0	3.8
10-12"	12	229.1	2.6	16	225.0	3.6
>12-18"	15	332.2	5.0	15	326.2	4.9
>18-24"	1	464.4	0.4	1	455.9	0.4
>24"	0	0.0	0.0	0	0.0	0.0
Total	**574**		**44.9**	**573**		**46.2**

	2010-11			2011-12		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	73	56.4	4.1	67	56.2	3.8
4-5"	349	61.6	21.5	345	61.4	21.2
6-7"	95	86.7	8.2	105	86.3	9.1
8-9"	20	160.3	3.3	19	159.7	3.1
10-12"	21	223.9	4.6	21	223.1	4.6
>12-18"	15	324.7	4.9	15	323.6	4.9
>18-24"	1	453.9	0.4	1	452.3	0.4
>24"	0	0.0	0.0	0	0.0	0.0
Total	**574**		**47.0**	**574**		**47.0**

	2012-13		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	63	55.8	3.5
4-5"	332	60.9	20.2
6-7"	119	85.6	10.2
8-9"	20	158.4	3.2
10-12"	23	221.3	5.1
>12-18"	15	321.0	4.8
>18-24"	1	448.6	0.4
>24"	0	0.0	0.0
Total	**573**		**47.5**

Scotia Gas Networks - Scotland

Table A15.11 - Services replacement matrix for 2008-9 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	15,915	502.0	8.0	16,074	499.1	8.0
services transferred	15,915	306.3	4.9	16,074	304.6	4.9
non domestic services	339	1,709.3	0.6	337	1,697.7	0.6
Total	**32,169**		**13.4**	**32,485**		**13.5**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	16,229	498.2	8.1	16,382	496.3	8.1
services transferred	16,229	304.0	4.9	16,382	302.9	5.0
non domestic services	335	1,695.3	0.6	333	1,686.6	0.6
Total	**32,793**		**13.6**	**33,096**		**13.7**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	16,558	493.5	8.2			
services transferred	16,558	301.1	5.0			
non domestic services	331	1,681.0	0.6			
Total	**33,447**		**13.7**			

Table A15.12 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	76	61.7	4.7	55	61.5	3.4
4-5"	138	67.4	9.3	137	67.1	9.2
6-7"	46	94.8	4.4	64	94.5	6.0
8-9"	26	175.3	4.6	28	174.8	5.0
10-12"	19	245.0	4.7	20	244.2	5.0
>12-18"	6	355.3	2.2	6	354.1	2.2
>18-24"	6	496.5	3.0	6	494.9	3.0
>24"	1	612.7	0.6	1	610.7	0.5
Total	**319**		**33.4**	**318**		**34.3**

	2010-11			2011-12		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	45	62.0	2.8	44	62.2	2.7
4-5"	156	67.7	10.5	152	67.9	10.3
6-7"	61	95.2	5.9	67	95.6	6.4
8-9"	22	176.2	3.9	23	176.8	4.0
10-12"	19	246.2	4.7	17	247.0	4.3
>12-18"	6	357.0	2.2	6	358.1	2.1
>18-24"	6	498.9	3.0	6	500.6	2.9
>24"	1	615.7	0.5	1	617.7	0.8
Total	**317**		**33.6**	**316**		**33.6**

	2012-13		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	36	62.3	2.2
4-5"	146	68.0	9.9
6-7"	74	95.6	7.1
8-9"	26	176.9	4.6
10-12"	20	247.2	4.9
>12-18"	6	358.4	2.2
>18-24"	6	501.0	3.1
>24"	1	618.3	0.4
Total	**315**		**34.5**

Scotia Gas Networks - Southern

Table A15.13 - Services replacement matrix for 2008-9 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	45,287	534.9	24.2	47,884	531.2	25.4
services transferred	25,438	326.4	8.3	27,509	324.1	8.9
non domestic services	748	1,821.1	1.4	799	1,809.8	1.4
Total	**71,473**		**33.9**	**76,192**		**35.8**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	47,179	529.1	25.0	46,659	527.0	24.6
services transferred	27,684	322.8	8.9	27,942	321.5	9.0
non domestic services	814	1,802.2	1.5	809	1,795.2	1.5
Total	**75,677**		**35.4**	**75,410**		**35.0**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	46,403	524.8	24.4			
services transferred	28,337	320.1	9.1			
non domestic services	806	1,786.3	1.4			
Total	**75,546**		**34.9**			

Table A15.14 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	44	62.5	2.8	26	62.8	1.6
4-5"	409	68.2	27.9	490	68.5	33.6
6-7"	131	96.0	12.6	134	96.4	13.0
8-9"	56	177.5	9.9	43	178.3	7.7
10-12"	45	248.0	11.2	37	249.1	9.2
>12-18"	16	359.7	5.7	16	361.3	5.8
>18-24"	16	502.7	8.0	16	504.9	8.1
>24"	5	620.4	3.2	7	623.1	4.5
Total	**723**		**81.3**	**770**		**83.5**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	29	62.2	1.8	31	62.3	2.0
4-5"	465	67.9	31.6	455	68.0	30.9
6-7"	144	95.5	13.8	143	95.7	13.7
8-9"	46	176.6	8.2	52	177.0	9.1
10-12"	44	246.8	10.9	47	247.3	11.6
>12-18"	17	357.8	6.1	18	358.6	6.5
>18-24"	17	500.1	8.5	18	501.2	9.1
>24"	6	617.2	3.9	5	618.6	3.0
Total	**769**		**84.7**	**769**		**85.9**
	2012-13					
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**			
</=3"	28	61.9	1.7			
4-5"	421	67.5	28.4			
6-7"	166	95.0	15.8			
8-9"	65	175.8	11.4			
10-12"	47	245.6	11.6			
>12-18"	18	356.2	6.4			
>18-24"	18	497.8	8.9			
>24"	5	614.3	3.3			
Total	**768**		**87.5**			

Wales and West Utilities - Wales and West

Table A15.15 - Services replacement matrix for 2008-9 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	25,105	490.0	12.3	25,047	487.6	12.2
services transferred	23,243	299.1	7.0	23,187	297.7	6.9
non domestic services	349	1,668.5	0.6	349	1,659.5	0.6
Total	**48,697**		**19.8**	**48,583**		**19.7**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	25,047	484.7	12.1	24,854	482.1	12.0
services transferred	23,076	295.9	6.8	22,971	294.3	6.8
non domestic services	349	1,650.5	0.6	349	1,641.5	0.6
Total	**48,472**		**19.5**	**48,174**		**19.3**

	2012-13		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	24,794	480.4	11.9
services transferred	22,921	293.3	6.7
non domestic services	349	1,635.5	0.6
Total	**48,064**		**19.2**

Table A15.16 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	49	59.2	2.9	45	59.1	2.6
4-5"	237	64.7	15.3	233	64.5	15.0
6-7"	75	91.0	6.8	76	90.8	6.9
8-9"	36	168.3	6.0	41	167.9	6.9
10-12"	13	235.1	3.1	14	234.6	3.4
>12-18"	10	341.0	3.5	11	340.1	3.7
>18-24"	0	0.0	0.0	0	0.0	0.0
>24"	0	0.0	0.0	0	0.0	0.0
Total	**420**		**37.7**	**420**		**38.5**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	43	58.5	2.5	43	58.0	2.5
4-5"	217	63.9	13.9	202	63.3	12.8
6-7"	79	89.8	7.1	84	89.1	7.5
8-9"	50	166.2	8.3	56	164.8	9.2
10-12"	19	232.2	4.5	23	230.2	5.4
>12-18"	11	336.7	3.8	12	333.8	4.0
>18-24"	0	0.0	0.0	0	0.0	0.0
>24"	0	0.0	0.0	0	0.0	0.0
Total	**420**		**40.1**	**420**		**41.3**
	2012-13					
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**			
</=3"	42	56.9	2.4			
4-5"	194	62.2	12.1			
6-7"	86	87.5	7.5			
8-9"	61	161.8	9.8			
10-12"	25	226.0	5.7			
>12-18"	12	327.8	4.1			
>18-24"	0	0.0	0.0			
>24"	0	0.0	0.0			
Total	**420**		**41.6**			

Appendix 16 - Cost of Capital

Introduction

1.1. This appendix provides greater detail on:

- the data and methodology used by Ofgem in its quantitative analysis of the relative risk of gas distribution and transmission;
- Ofgem's consideration of what relative risks should be included and what relative risks should be excluded, when evaluating the risk differentials between gas distribution and transmission;
- the submissions from the GDNs and others in respect of relative risk analysis, and Ofgem's views on those submissions; and
- the submissions from the GDNs and others on other aspects of the cost of capital, and Ofgem's views on those submissions.

Ofgem's relative risk analysis

1.2. Our analysis of relative risk has focused on a bottom up analysis of GDNs' and TOs' performance against allowances in previous price control periods, both on a year-on-year basis and across the five year period. In all cases within this section, the relative risks being considered are explicitly those under the forthcoming price control from 2008-13 for the GDNs, compared to the TPCR 2007-12 price control.

1.3. In addition, the network owners (NWOs) may face asymmetric risk, if the point estimate chosen by the regulator for the price control is different to the expected performance. Some risks faced by the NWOs may be subject to a skewed risk profile, where the upside risks and downside risks are of differing scales or probabilities.

1.4. The bottom-up variance analysis is based on analysing all operational risks, without segregation into systematic and non-systematic risks. If we adhered strictly to a CAPM framework, there would be an argument for taking account of systematic risks only. By contrast, Ofgem's objective when setting the allowed return on equity is to ensure that NWOs are able to finance their activities, and that there are appropriate incentives to invest. Both of these are impacted by the overall package of risks taken, including systematic and non-systematic risks.

1.5. In Transmission, the value chosen for the cost of equity was 7.0 per cent. This reflected Ofgem's view of the appropriate cost of equity for the transmission networks as part of the overall package of the transmission price control review. In TPCR final proposals[32], we outlined that this was after an initial review which indicated that transmission may be less risky than distribution, but that there was insufficient evidence gathered to prove this to be the case.

[32] 206/06 "Transmission Price Control Review, Final Proposals", Ofgem, 2006.

1.6. Our relative risk analysis does not include a number of generic risks faced by NWOs, including political risk, regulatory consistency, generic shareholder risk and the risk of inflation in financing costs. We have attempted in our analysis to quantify the materiality of the risk differential between GDNs and TOs against the generic risks faced by both where those risks are quantifiable. Some risks perceived by investors in regulated companies, e.g. political risk, are considered to be non-zero but not quantifiable. In that case, any attempt to quantify the cost of capital impact of the relative risk differential is likely to overstate the materiality.

Key principles

1.7. The following steps are required to produce a bottom-up relative risk analysis:

- firstly, that the expenditure of the GDNs and the TOs can be allocated into discrete categories;
- secondly, that the incentive strength applying to each can be measured; and
- thirdly, that the variability of each, at least on a relative basis, can be estimated.

1.8. All of the analysis is done by comparison to the RAV. The cost of capital is set as a return on RAV, and analysing the risk as a proportion of RAV is consistent. The return on RAV is the measure used by the regulator for allowing the investors in network assets to obtain a return on their investment. The return is adjusted for incentive strengths, since this represents the shareholder gain/loss against the allowed cost of capital.

Data used

1.9. For operating expenditure and replacement expenditure, we considered variability as measured by:

- combined performance against price control allowances across the five year period;
- annual performance against price control allowances; and
- annual change in performance against price control allowances.

1.10. We have analysed actual opex versus like-for-like allowances over the previous price control period for TOs and GDNs. We have excluded pension deficit funding costs for all companies and shrinkage costs for GDNs since measures are in place to reduce or remove companies' exposure to these factors going forward.

1.11. The HSE-mandated repex programme is specific to Gas Distribution and there is no equivalent within the TO data. We have not considered workload risk within the repex programme, since GDNs are protected by the incentive mechanism, which adjusts allowances for changes in workload, both for services and mains repex, for the coming price control.

1.12. We have analysed capital expenditure risk in three ways. There are some major differences between the measurement of capex risk and the other categories:

- firstly, the potential for projects and portfolios to change sharply in scope. A project may overspend, in some cases substantially, without an increase in underlying unit cost, due to an increase in the scope of the project. This may not increase the long-term costs, as it may offset the need for future capex;
- secondly, capital expenditure is more discretionary and flexible than operating expenditure. Many capital expenditure projects are in whole or in part to meet ongoing security of supply requirements, rather than short-term mandatory outputs. This is an important part of managing the capital base of the networks, but allows for scope increases to be incorporated in the capital plan and potentially offset against scope reductions elsewhere, as would likely be the case for an unregulated business; and
- thirdly, capital expenditure can fluctuate sharply from year-to-year, without necessarily reflecting a high risk. In practice, if out-turn capital expenditure fluctuates more than allowed capital expenditure, this may be due to efficient deferral or acceleration of costs as part of project management. Where this does not lead to a cumulative overspend, then it does not necessarily reflect a downside risk.

1.13. To measure like-for-like risk of capital expenditure, we have analysed the risk associated with capital expenditure projects by comparing the forecast project cost to the out-turn for 9 gas distribution, 5 gas transmission and 17 electricity transmission projects. This was done using comparisons of initial project submissions to resubmissions and actuals, depending on what data was available for each project.

1.14. The data compiled was the project cost variance and the time to complete. This allows comparison of total variance and annualised equivalent variance. We looked at splitting the cost variance by category, but contractor cost variance dominates all other categories. Such changes can be as a result of either higher unit costs, scope miscalculations, or unexpected environmental factors (e.g. Foot & Mouth).

1.15. This metric gives the best measure of true like-for-like variability. It needs to be considered in the context of total capital expenditure, including the impact of diversification offset by the risk of increases in capex workload.

1.16. We have also analysed the annual changes in spend by major category of capex. This analysis is on an annual actual versus actual basis. For this purpose, GDN and TO capex have been allocated into three or four material and distinct categories of expenditure. Then, a combined standard deviation is estimated by summing the variances of the different categories.

1.17. Finally, we considered top-down analysis of capital expenditure. We have only considered this over each total price control period, where year-to-year fluctuations, which may simply be caused by changes in the timing of specific projects do not impact the analysis. To attempt to get a better pattern, we analysed all the electricity transmission price controls back to 1991.

1.18. In addition, we have considered the risk of changes to tax rates. In the forthcoming control, the GDNs are forecast to pay little tax. Therefore, the transmission companies face higher exposure to changes in tax rates, levels of capital allowances, or classification of costs for tax purposes. We have reviewed all the changes to tax rates and the capital allowance mechanism since inception, and estimated the average annual change to be five per cent. This is not a material input to the calculation. There is a perceived risk that HMRC might revise its treatment of repex costs if the relevant accounting treatment changes, and this would have a larger impact, but we have explicitly agreed to mitigate tax costs arising via the Income Adjusting Event mechanism.

Data Analysis

1.19. For opex, repex, and project capex, the data used appears to have been of good quality. However, when analysing combined price control performance against allowances, there is an inevitable lack of data – 8 GDNs and 4 TOs. Therefore the analysis of annual data is likely to be more robust.

1.20. In each case, we measured the annual changes and performance against allowances on a percentage basis, to control for the impact of differences in size. We did take care not to compare percentages where the underlying expenditure was different in form or completely different in materiality. As described in the "Data used" section, all data was of a comparable materiality. The largest differences were in respect of the Scottish TOs, which are smaller. We do not believe that this impacted the overall results.

1.21. For some categories, the GDN data may also be weakened by the change in industry structure during the last price control period. However, in most cases, we do not conclude that this will have materially impacted the conclusions.

1.22. The standard deviations of the annualised measures (both annual versus. allowance and annual versus prior year) were then calculated for GDNs and TOs. For the different categories, we performed standard t-tests and F-tests to measure significant differentials in average performance and in variability of performance, and chi-squared tests to assess confidence intervals for the variability of performance. We also tested the data for the five years. Given the smaller data set, the statistical tests were less conclusive and the confidence intervals wider.

1.23. When measuring standard deviation, we excluded the impact of the skew of actual returns to allowances. This is considered separately as an asymmetric risk, in the section beginning in paragraph 1.41 below. We also recognise that some of the statistical tests imply a normal distribution. The annualised change in costs, expressed as a percentage, will not follow a normal distribution. We feel that our conclusions are sufficiently strong that this would not impact the conclusions, and, in addition are supported by qualitative reasoning.

1.24. Overall, we came up with statistically significant differences in variability of out-turns which indicated the following:

- capex is more risky than repex (measured across the price control, and annually for GDNs);
- repex is more risky than opex. (measured annually);
- incremental and project capex are similarly risky; and
- opex is more risky than tax.

1.25. With respect to opex, the TO and GDN data suggested that, measured as a percentage of opex expenditure, the risks taken were comparable. However, with respect to capital expenditure, the various measures suggested, on balance, that the risk faced by GDNs may be greater than the risk faced by TOs, as a percentage of expenditure.

1.26. There are three main reasons why we conclude this may be the case:

- greater experience – the TOs undertake several large projects during the price control period and a large number of smaller projects. By contrast, the majority of the GDNs undertook one large project and otherwise none over £5m in the last control;
- portfolio diversification effect – larger number of individual projects reduces overall risk; and
- portfolio management effect – the larger number of individual transmission projects provides a greater capability to manage and allocate resources and to offset changes in project scope.

1.27. On a total project basis and on an annualised project basis, gas distribution projects appear statistically more risky than transmission projects.

1.28. Equally, the average change in capex by categories was significantly more variable for the GDNs than the TOs. This testing required adjustments with respect to a relatively large number of data points where capex changes sharply year on year, as discussed in 1.12 above.

1.29. We have reviewed the performance of the TOs against capex allowances back to 1991 using data also included in the TPCR Final Proposals. Total capex variance to allowance is smaller for TOs than for GDNs over the last control, but the differential is not statistically significant. However this is driven by two price controls where the TO underspent their capital expenditure allowance sharply. The project analysis suggests that like-for-like capex does not reduce sharply in cost. Therefore this impact is likely to be driven by manageable changes in the projects undertaken, rather than business risk.

1.30. Unmanageable variability as measured by overspend is low for the TOs. The overspend for the combined GDNs from 2002-07 against Transco's capital expenditure allowance was around 65 per cent and the standard deviation between the performance of each GDN was around 40 per cent. These are statistically significantly higher than the TO data, regardless of the small sample.

1.31. As a result we have taken the GDN data for variance (which is broadly consistent between total variance, incremental capex variance and project variance) and reduced to reflect the lower like-for-like variance of the TOs. This may understate the differential, to the extent that it may partially exclude the impact of portfolio diversification for the TOs, but this would not impact the overall conclusion.

Parameter selection for variability analysis

1.32. Table A16.1 below summarises our assessment of point estimates for total and annualised volatility in each area of expenditure, based on the input data described above. We have used a chi-squared test to estimate 95 per cent confidence intervals around this point estimate.

Table A16.1- Assessment of parameters for comparison of volatility for GDNs and TOs

	Total volatility over price control period		Annualised volatility	
Parameter	Point Estimate	95 % confidence interval	Point Estimate	95 % confidence interval
Opex volatility	10%	7%-17%	10%	9%-12%
Repex volatility	10%	7%-15%	18%	15%-22%
Capex volatility – GDNs	35%	23%-71%	25%	17%-48%
Capex volatility – TOs	25%	19%-38%	20%	15%-29%
Tax volatility	5%	n/a	5%	n/a

Results

1.33. The combined exposure as a percentage of RAV was then calculated for the TOs and GDNs as $\sqrt{\sum_i \frac{Z_i}{RAV} \delta_i \sigma^2{}_i}$ where for each category of expenditure i, Z_i is the allowed expenditure, δ_i is the incentive strength and $\sigma^2{}_i$ is the variance. Details of the calculations are given below. The conclusion is that there is a significant differential, on an annualised basis, as in table A16.2 below.

Table A16.2 – Risk differentials and confidence intervals between GDNs and TOs

	Five year total		Annualised	
	Point estimate	95% confidence interval	Point estimate	95% confidence interval
Differential	1.1%	-0.7% to 2.9%	0.3%	0.17% to 0.45%

1.34. The most surprising assumption underlying this analysis may be that the capital expenditure volatility measure is higher for the GDNs for the TOs. As described above, we are not reliant on a single measure to reach this conclusion, but it is based on consideration of a number of measures producing comparable results.

1.35. However, we have also considered the sensitivity of assuming the variability of TO and GDN capex are the same. This increases the measure of transmission risk, but does not change the primary conclusions above, that the GDN risk measure is higher, and for annualised data that it is significantly higher with at the 95 per cent confidence level.

1.36. A summary table of the five year price control relative risk calculation is as follows.

Table A16.3 - Five year price control relative risk calculation

Category	**Transmission**					
	Total spend (% of opening RAV)	**Incentive strength**	**Standard deviation**	**Exposure (% of opening RAV)**	**Variance**	**Total Standard deviation as %age of RAV**
Non-load capex	26.6%	25%	25%	1.7%	0.03%	
Load related capex	22.1%	25%	25%	1.4%	0.02%	
Controllable opex	12.6%	100%	10%	1.3%	0.02%	
Tax	8.4%	100%	5%	0.4%	0.00%	
Total	**69.7%**				**0.06%**	**2.5%**

Category	**Gas Distribution**					
	Total spend (% of opening RAV)	**Incentive strength**	**Standard deviation**	**Exposure (% of opening RAV)**	**Variance**	**Total Standard deviation as %age of RAV**
Repex	29.9%	33%	10%	1.0%	0.01%	
Capex	14.2%	33%	35%	1.6%	0.03%	
Controllable opex	30.6%	100%	10%	3.1%	0.09%	
Tax	1.2%	100%	5%	0.1%	0.00%	
Total	**75.9%**				**0.13%**	**3.6%**

Differential = Total GD standard deviation as %age of opening RAV (3.6%) less total Transmission standard deviation as %age of opening RAV (2.5%) = 1.1%.

1.37. A summary table of the annualised relative risk calculation is as follows.

Table A16.4 - Annualised relative risk calculation

Category	Transmission					
	Total spend (% of opening RAV)	Incentive strength	Standard deviation	Exposure (% of opening RAV)	Variance	Total Standard deviation as %age of RAV
Non-load capex	5.3%	25%	20%	0.3%	0.001%	
Load related capex	4.4%	25%	20%	0.2%	0.000%	
Controllable opex	2.5%	100%	10%	0.3%	0.001%	
Tax	1.7%	100%	5%	0.1%	0.000%	
	13.9%				0.002%	0.4%
Category	Gas Distribution					
	Total spend (% of opening RAV)	Incentive strength	Standard deviation	Exposure (% of opening RAV)	Variance	Total Standard deviation as %age of RAV
Repx	6.0%	33%	18%	0.4%	0.001%	
Capex	2.8%	33%	25%	0.2%	0.001%	
Controllable opex	6.1%	100%	10%	0.6%	0.004%	
Tax	0.2%	100%	5%	0.0%	0.000%	
	15.2%				0.006%	0.7%

Differential = Total GD standard deviation as %age of opening RAV (0.7%) less total Transmission standard deviation as %age of opening RAV (0.4%) = 0.3%.

1.38. The risk differential is particularly evident from the annualised analysis, which is likely to be more accurate as it reflects more data points, although it is also reflective of the assumption that uncontrollable capex risk is higher over the five year period, due to the greater intra-year correlation between the risks faced on large capex projects.

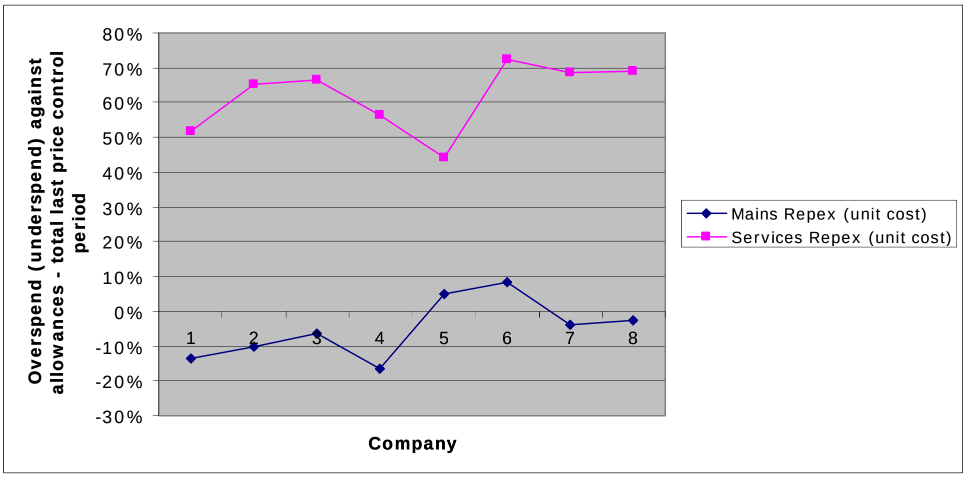
1.39. In addition we have performed sensitivity analysis which has shown that changes to the input parameters within sensible boundaries do not materially impact the conclusions.

1.40. The cost of equity and cost of debt inputs to Ofgem’s cost of capital assumptions are based on an assessment of the annualised returns required by investors. It seems likely that investors will be more concerned with this measure than with average risk over the price control period. We consider that it may be appropriate to place greater weight on the results of the annualised analysis.

Asymmetric & regulatory risk

1.41. In addition to comparing the variability of performance, we performed t-tests to compare the absolute differentials in performance. For example, figure A16.1 shows the difference in performance against opex allowances for TOs and GDNs.

Figure A16.1- Individual GDN performance against the mains replacement and service repex unit cost allowances



1.42. Figure A16.1 illustrates one of our initial conclusions – that the concept of regulatory risk applying to the package is separate to the underlying business risk. It is clear from the picture,that the unit cost allowances for mains replacement closely matched of the actual costs, whereas the service replacement unit costs exceeded expectations. This does not mean that this will be the case for the future, and so this absolute differential was excluded from the variability analysis above. The underlying standard deviation of the results is however similar.

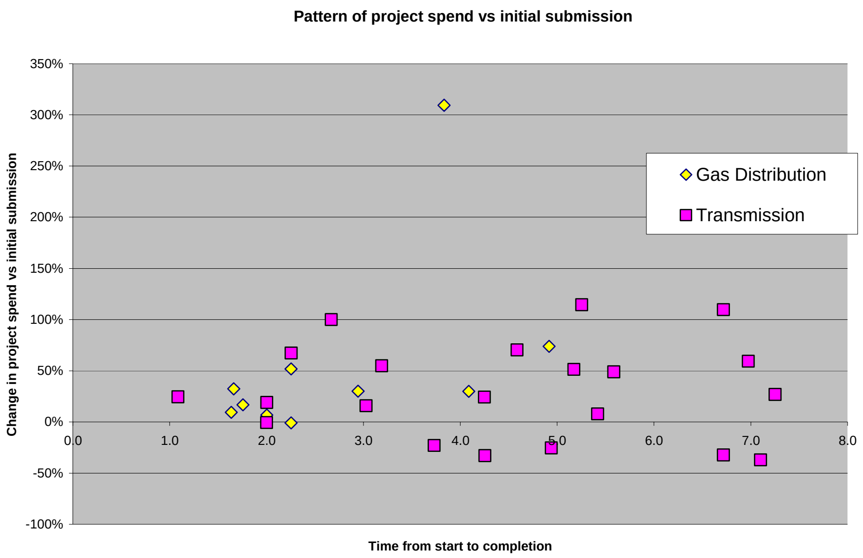
1.43. A similar picture can be seen for the GDNs and TOs in respect to opex, where the GDNs broadly performed in line with expectations during the 2002-07 price control (excluding pensions and shrinkage), whereas the TOs underspent their allowances. The relative spread of performance was similar.

1.44. In the last price control, the GDNs took losses as a result of several large areas of cost over-run, over and above normal fluctuations in costs. These included shrinkage and service repex allowances - both of which resulted in cost overruns for the GDNs of close to £100 million or around 0.8 per cent of RAV.

1.45. In addition, the GDNs are subject to comparative competition, which reduces the benefit of asymmetric information.

1.46. There is evidence from the project data that individual capital projects appear to over-run on average. The outturn versus initial submission was significantly different from zero (using a t-test). Figure A16.2 below plots the spend against initial forecast by project for the 31 projects analysed.

Figure A16.2 - Capital expenditure project out-turn compared to initial submission



1.47. The TOs are likely to have more flexibility to manage their portfolio of investment projects. For the GDNs, since their capital expenditure is more concentrated around one or two major LTS projects and to customer connections, they will be more exposed to the consequences of any skew in capital expenditure performance.

1.48. This is not sufficient evidence to quantitatively demonstrate a significant differential between transmission and distribution. However, as summarised in chapter 9, to the extent that we feel there is any differential in asymmetric risk, it is likely that the asymmetric risk faced by the GDNs is at least as high as that faced by the TOs.

Other risks

1.49. We have not included in the above analysis various generic risks. A rationale is outlined in this section.

Operational failure and asset stranding risks

1.50. The GDNs have argued that they face greater operational failure risks, due to the higher reliability built into the transmission networks. They have referred to their security of supply obligations and the greater dangers of gas by comparison to electricity as reasons for a higher cost of capital for the distribution networks.

1.51. Whilst this may be the case, analysis of the interruptions data suggests that these operational risks have a limited cash impact, above the costs allowed within the opex allowances to manage these risks and to pay compensation for normal levels of interruption. There has only been one major interruption event in the last twenty-five years.

1.52. In addition, the GDNs have raised the risk of stranded assets, when gas runs out. This would also be an issue for the NTS but not for the electricity transmission companies.

1.53. The advent of LNG and increase in transportation of gas suggests there is little risk of gas running out in the forthcoming decades. Nevertheless, should it appear that the asset lives used for depreciation purposes no longer reflect the useful lives of the assets, the approach to depreciation will need to be reconsidered at future reviews.

Interest Rate Risks

1.54. Ofgem's approach to the cost of capital assumes that the current RAV is financed with existing debt. On that basis, we consider that the financing of the opening RAV requires no risk differential and arguably no risk premium since the cost of financing is a sunk cost. Refinancing of embedded debt over the forthcoming control period will result in a risk to the GDNs and the TOs, but there should not be a risk differential.

1.55. There will be a risk differential relating to the different rates of RAV growth to be financed at prevailing market rates. The RAV growth for TOs is on average 20% over the review period by comparison to 10 per cent for the GDNs. However, when this is multiplied by the interest rate, the variability of interest and the proportion of debt financing, the total relative risk is immaterial, so has been excluded from the analysis.

Inflation Risk

1.56. The GDNs and the TOs face RPI basis risk, to the extent that they have costs which are not indexed to RPI. The GDNs have outlined other indices which they argue are more closely linked to their underlying cost base. Ofgem have concluded that RPI still forms the most appropriate measure when setting price control allowances.

1.57. As a result, inflation risk should be taken account of in setting price control allowances. However, the risk relating to cost inflation will already be recognised in the analysis of costs described above. The measures of variability used will include the impact of changes in costs against allowances or prior year because of cost inflation being different to RPI.

1.58. The risk of inflation in financing costs is not included in the analysis. The cost of capital is set on a real basis. Whilst equity investors expect dividends to rise with inflation, debt interest is normally on a nominal basis, and we assume in our financing model that the NWOs fund themselves on a nominal basis. However this risk is common to GDNs and TOs.

Incentive schemes

1.59. Other than the rolling incentive, the RPI-X incentive and the mains replacement incentive, other smaller incentive schemes are not included in the analysis. Our initial conclusion is that in general these are small and reflect low risk by comparison to the main categories of expenditure analysed above. We will reflect further as we finalise the GDPCR package of incentives up to final proposals.

Political risk and regulatory consistency

1.60. Regulated companies including NWOs rely on the regulator to ensure that their asset value is retained. Therefore there is a risk, which is likely to be considered asymmetrical, that a change in the political climate could impact the value of the NWO assets, whether explicitly or through a change to the regulatory regime.

1.61. Qualitatively, transmission companies could be considered more at risk of political interference, since they are more exposed to strategic considerations in the context of wider energy policy. However it is not clear whether this is an asymmetric risk, and if so whether it is more likely to favour or penalise TOs.

1.62. In addition, where outside commentators refer to the regulatory framework faced by UK regulated networks; this is generally perceived to be benign. For example, a Moody's (2005)[33] report on rating electric utilities categorised the UK framework in their lowest category of risk.

1.63. Whilst there will remain some exposure to investors in regulated assets, since this risk relates to behaviour outside the current regulatory paradigm, it cannot be taken into consideration. It is likely to result in total generic risk being perceived as higher than measurable risk. This is a qualitative factor to take into consideration when considering the impact on total cost of equity.

Generic Shareholder Risks and treatment of diversifiable risk

1.64. Oxera's analysis for the GDNs[34], considers the range of asset betas and equity betas for energy utilities. This was also considered in Smithers (2006) [35]. These all

[33] "Rating Global Electric Utilities", Moody's, 2005, available on www.moodys.com
[34] "Is there a risk differential between energy networks", Oxera, 2007

indicate evidence of a sustained positive equity beta and asset beta for energy utilities.

1.65. Europe Economics (2006)[36] reviewed the underlying beta risks faced by another regulated company (BAA). Their conclusion was that the systematic risk associated with the costs incurred in operating the airport was negligible.

1.66. This suggests that, in theory, network utility (and water utility) asset betas, and by extension, equity betas, should not be significantly different from zero. The existence of the RAV should also reduce the systematic risk faced by NWOs. In practice, the data suggests that equity markets react to changes in general market conditions, with knock-on effects for the relative supply and demand for equity compared to debt, and few shares remain insulated. In this context, Ofgem has taken the view that the total equity return for investors in NWOs needs to be broadly consistent with the overall equity market return.

1.67. We have considered whether we should seek to explicitly exclude diversifiable risk, as suggested by the CAPM. This was the headline approach taken by Europe Economics (2006) in analysing the relative risks of the airport operator in operating different airports.

1.68. Oxera (2007b)[37], for BAA, analyse the relative risk using both beta measures and other measures which would be influenced by non-systematic risks, based on accounting and cash flow measures. This is based on the assumption that relative betas will be directly correlated to relative volatilities. Oxera's analysis appears to indicate that this approach of considering total risk (including systematic and non-systematic risk) produces a comparable relative risk position to market measures (which according to the CAPM theory would only relate to systematic risk). However, it does also appear to produce greater differentials. This may be partly due to the analysis (which is primarily intended to produce a relative risk picture) not therefore taking account of some generic risks also allowed for by equity investors.

1.69. In addition, the market risk analysis outlined by Oxera (2007a) for the GDNs and discussed further below suggests that any asset beta differential does not result from a differential in equity betas. The differential instead results from higher gearing. Higher gearing may be a consequence of either systematic or non-systematic risks. Both this evidence and the review of gearing versus equity betas in Smithers (2006) suggest that equity betas for energy companies are not correlated to gearing levels. We therefore conclude that investors may react to lower risk at least in part by expecting management to increase gearing, not by reducing their required rate of return on equity. This again suggests that both systematic and non-systematic risks need to be taken into consideration, as both impact the appropriate level of gearing and therefore the weighted average cost of capital.

[35] "Report on the Cost of Capital provided to Ofgem", Wright et al, 2006.
[36] "Cost of capital – estimating separate costs of capital for Heathrow and Gatwick", EE, December 2006
[37] "Stand-alone costs of capital of Heathrow, Gatwick and Stanstead airports". Oxera, May 2007(a)

1.70. Overall, we are analysing a variety of costs which are drawn from input markets (labour, materials and contractor costs) which are impacted by systematic factors. We consider that while the scale of these are impacted by non-systematic factors, it would be inappropriate to attempt to exclude any of these costs from the analysis.

Oxera's analysis of comparative risk

1.71. The main submission from the GDNs in respect of relative risk analysis was a report by Oxera (2007a).

1.72. Oxera's analysis includes three areas of work:

- Quantitative market analysis based on asset betas;
- Quantitative analysis based on regression of betas to asset and profit ratios; and
- Qualitative assessment of risk characteristics.

1.73. The quantitative study analyses companies that focus on one area of energy networks. The sample is heavily weighted towards US firms. We have compared to the sample prepared by Grant Thornton (2006)[38] as background to the Smithers (2006) report and have not identified any omissions. Oxera's analysis indicates that owners of gas transmission networks have asset betas around 0.2 lower than owners of gas distribution networks. This difference is statistically significant, indicating higher risk for distribution companies.

1.74. The US regulatory regime is different to the UK regulatory regime, to the extent that transmission and distribution companies are subject to regulation by different regulators. The distribution companies are regulated by PUCs (state regulators) which may have a perceived higher risk, due to their local accountability, political affiliation and their greater number. In addition, we understand that PUCs have tended to use more incentive regulation than FERC, which continues to use rate-of-return regulation. Therefore, a risk differential may be related to differences in the perceived risks of the different regulatory regimes.

1.75. Oxera has provided us with the data used in its study, enabling us to test the assumptions underlying its analysis. Our review indicates that many of these assumptions are sound. For example, it appears that the data reflects transmission versus distribution accurately, that there is no other difference in the sample that would explain the risk differential, and that equity beta is measured correctly.

1.76. We consider, however, that certain other assumptions may not be robust. These are discussed further below.

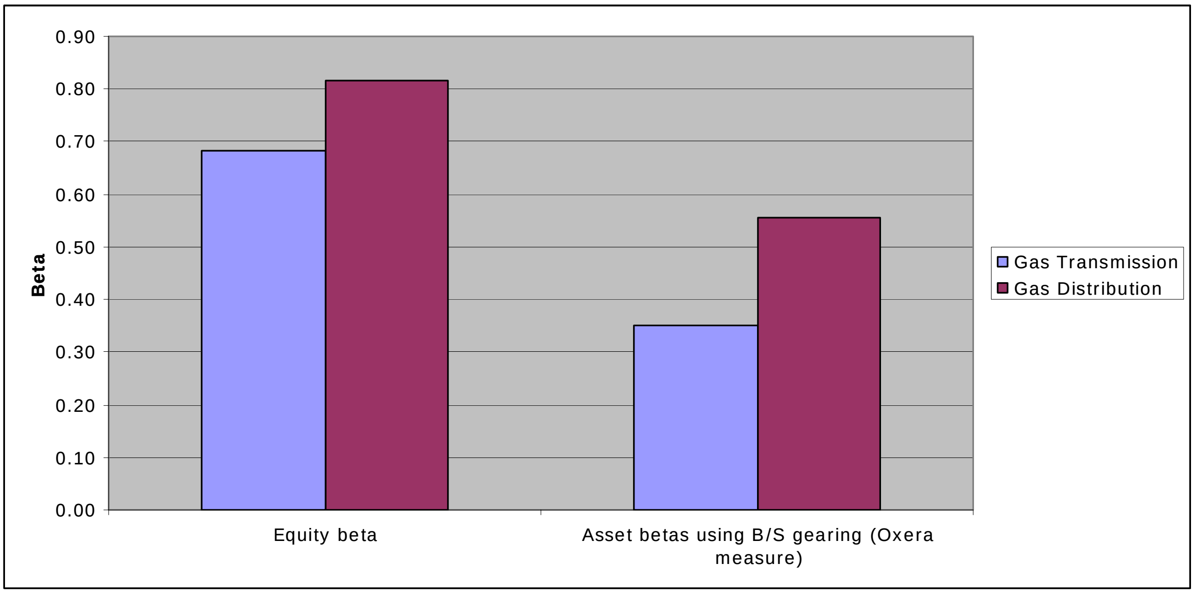
[38] "Utility Bond Analysis 1995-2005", Grant Thornton, June 2006,

Use of asset betas

1.77. Oxera has used asset betas to compare the relative riskiness of different sectors. Asset betas cannot be measured directly and must be inferred from equity betas, adjusted for the firm's level of gearing. This transformation is based on Modigliani and Miller's theory that equity betas rise with gearing. Oxera have used Miller's transformation, which also assumes zero debt beta and zero tax shield.

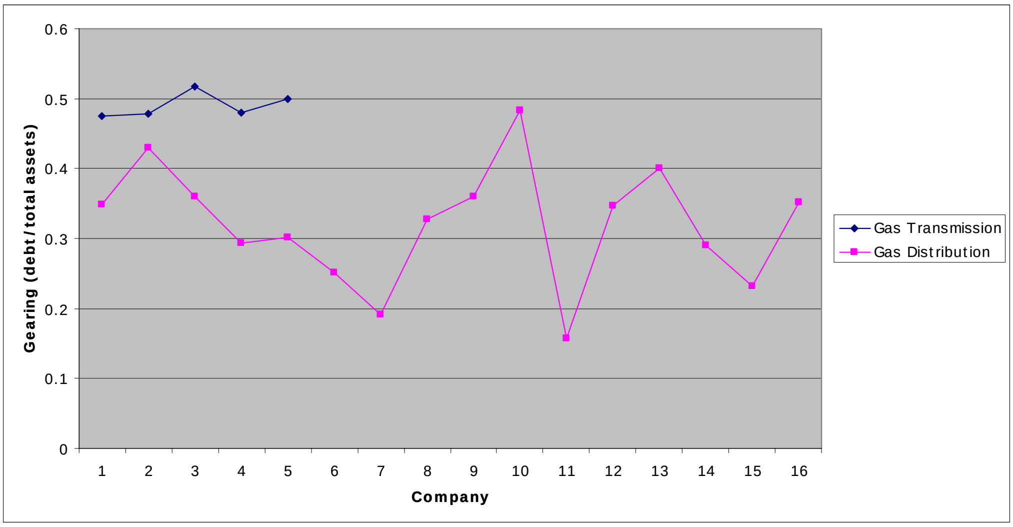
1.78. In this sample, equity betas in fact appear to be negatively correlated with gearing. This implies that asset betas are not a reliable measure of risk. The equity betas of gas distribution companies are higher than their transmission counterparts, but the difference is not significant at the 95 per cent level, using Oxera's statistical tests. Figure A16.3 below shows the equity betas and asset betas (as calculated by Oxera) for the two sectors.

Figure A16.3 - Comparison of equity betas and asset betas for the companies in the Oxera sample



1.79. The differential in asset betas as measured by Oxera reflects significantly higher levels of gearing (measured as debt/total assets) among gas transmission companies. Figure A16.4 below illustrates this. If two companies have the same equity beta, the company with higher gearing will have a lower implied asset beta.

Figure A16.4 - Comparison of gearing for gas transmission and gas distribution companies in Oxera's sample



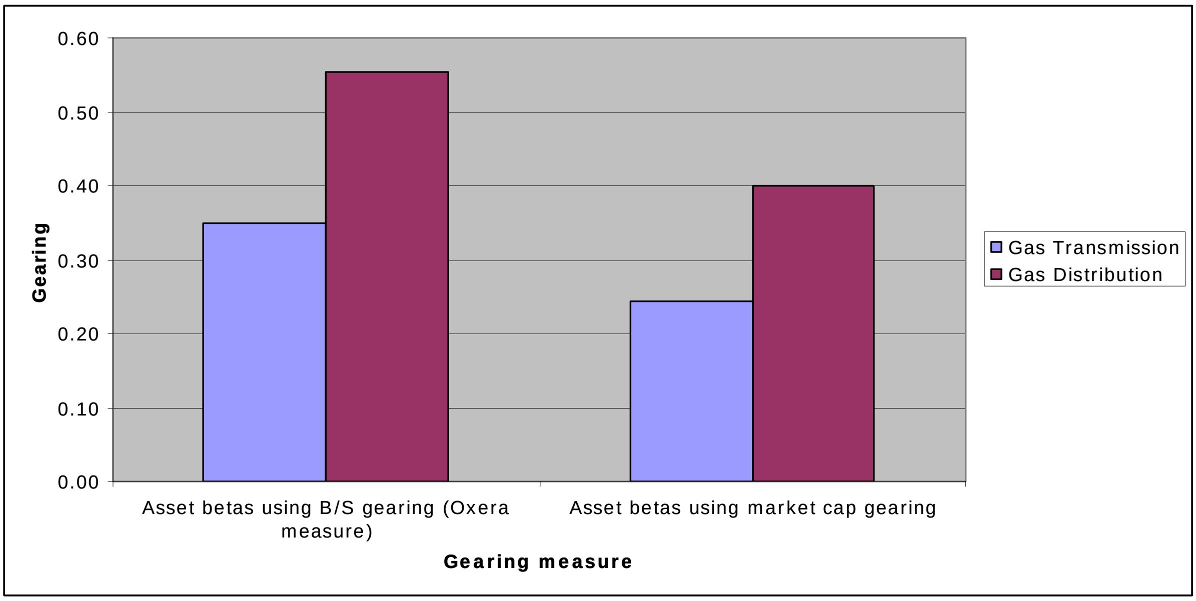
1.80. This gearing differential (which is statistically significant at the 99.9 per cent level) may itself imply that gas transmission companies are lower risk. Shareholders will accept higher levels of debt in companies that are perceived as lower risk.

Measure of gearing

1.81. Oxera has used a balance sheet measure of gearing in its calculation of asset betas. Given that its analysis is based on equity market data, we consider that a market based measure of gearing is more appropriate.

1.82. If asset betas are calculated using a debt/market cap gearing measure rather than a debt/total assets measure, the differential between transmission and distribution companies is smaller (around 0.15) and is no longer significant at the 95 per cent level. Figure A16.5 below illustrates the difference between the two measures.

Figure A16.5 - Relative risk measured by asset beta – comparison of balance sheet gearing measure to market gearing measure



Market data – conclusion

1.83. We consider that while the factors set out above may weaken Oxera's conclusions on the systematic risk of gas distribution versus transmission, they do not invalidate the overall conclusion that gas distribution betas are higher.

Remainder of Oxera's analysis

1.84. Oxera have also performed a number of regressions of financial ratios to betas, and used this to demonstrate that the expected beta of the gas distribution companies, based on these regressions, would be higher.

1.85. In principle, Oxera's analysis is consistent with our conclusions. However, Oxera's conclusions are based on a number of potentially highly variable inputs. We would expect the confidence intervals around the Oxera analysis to be higher than our bottom-up analysis.

1.86. In addition, Oxera's data does not focus on the regulatory asset measures used by the regulator when setting cost of capital. Ofgem will not give a premium to GDNs or other regulated companies because of differences in balance sheet and income statement measures. Our analysis focuses on whether the GDNs are able to finance their activities using measures based on regulatory asset measures. If we give GDNs additional returns to reflect differences in balance sheet ratios, then the GDNs would effectively be getting returns twice.

1.87. Oxera have also presented qualitative factors. Where these are relevant to the forthcoming price control, we consider that they are taken account of in our quantitative risk analysis.

Impact on cost of equity

1.88. We have attempted to quantify the materiality of the risk differential against the generic risks, as a sense check prior to proposing an adjustment to the cost of capital. This has been done using the same methodology as for the operating cost analysis.

1.89. Using assumptions on measurable generic risks faced, we have estimated the differential to be of the order of 10-20 per cent of the measurable risks. However, this should form a cap, as the range of measurable risks excludes generic equity risk and political risk. Our proposal that the cost of equity for gas distribution should be at least as high and up to 0.5 per cent higher than for transmission appears consistent with this conclusions.

Other aspects of the cost of capital

Cost of Equity

1.90. CEPA[39] have submitted a detailed review of the cost of capital. In particular, they argue for a lower cost of debt, based on evidence over the past five years (discussed in 1.97 below), and for a lower cost of equity, based on evidence from market to RAV ratios.

1.91. Oxera (2007c)[40] have submitted a rebuttal analysis to CEPA's arguments on market to RAV ratios.

1.92. On balance, we agree with Oxera that market to RAV ratios within the UK market cannot be used to justify a cost of capital for the GDNs. Specifically, we consider there are too many degrees of freedom between the market/RAV ratio and the cost of capital. This requires assumptions on an investor's expectations for performance against operational targets, their expectations for funding cost, and their views on future cost of capital policy by the regulator.

1.93. If the GDNs and transmission networks were all traded on the UK market, then we consider that the market/RAV ratio would be a useful measure of relative risk and changing perceptions of risk. Since this is not the case, we concur that the cost of equity interpreted by this method can only be a sense check. On this basis, the values produced by CEPA are, on this basis, comparable to our calculations of the cost of equity.

[39] "The Allowed Cost of Capital. Ofgem: GDPCR 2008-13", CEPA, 2007.
[40] "Do market-to-asset ratios provide reliable evidence on the cost of capital", Oxera, 2007.

1.94. Scotia Gas Networks have argued that the use of the Dividend Growth Model (DGM) points to a higher cost of equity. As with the market/RAV ratio above, it is our view that the DGM can only produce an estimate of the cost of capital. To derive a cost of capital from the DGM requires assumptions of investors' expected rate of growth in dividends over the long-term, and also the value they would place on any likely disposals of assets or other returns of value to shareholders.

1.95. In addition, there is a circularity implied by any use of the DGM. If Ofgem are perceived to consider the DGM as a relevant influence on the cost of capital, then this will itself impact investors' attitudes and the dividend policies of the investors.

1.96. As such, we consider that the DGM also provides a sense check on the cost of capital, rather than a number which can be used without reservation. The levels suggested by Scotia are, whilst higher, of a comparable materiality to our proposed range of values for the cost of equity.

Cost of Debt

1.97. CEPA have also argued for a shorter-term analysis of the cost of debt, and using five year averages have concluded that a 3 per cent cost of debt is sufficient.

1.98. On balance, Ofgem feels it is important to maintain an approach to the cost of capital which balances the short-term and long-term cost of debt financing. To attempt to use the recent lower rates would appear opportunist in the context of an industry which has and continues to finance long-term assets with a mix of medium-term and long-term debt.

1.99. Oxera have also submitted an analysis of a variety of possible measures for the cost of debt. Their analysis demonstrates that certain measures can be used which imply a higher cost of debt and equity.

1.100. Their analysis also includes many measures (including their calculation of the 10 year trailing average debt cost) which are below Ofgem's assumption. Oxera's range of measures is consistent with our parameters used in the vanilla WACC. As outlined in chapter 9, we are of the view that our cost of debt proposals sensibly balances the cost of financing the networks over time.

Gearing

1.101. Oxera also argue that the use of 62.5 per cent gearing invalidates our cost of debt and equity and that they would need to be increased. In respect of the cost of debt, there is no evidence that the rating agencies or the financial markets view 2.5 per cent as material and would require a higher cost of debt. In respect of the cost of equity, we do not agree with this conclusion, as discussed in 1.69 above.

Appendix 17 – Calculating allowed revenue

Allowances

1.1. We have calculated our updated proposals for the five year control using an Excel spreadsheet (the financial model). The version of the model used to set updated proposals is very similar to the version used at initial proposals. The previous version was audited by an external firm (PKF) to ensure its arithmetic accuracy and that its calculations of allowed revenues are consistent with our financial, regulatory and economic assumptions. The updated model (unaudited) will be published shortly after this document.

Calculating allowed revenue

1.2. Tables A17.1 to A17.8 demonstrates the calculation of the price control allowances and projected RAV roll forward for 2008-13 for each of the eight GDNs. The calculation of the movement in the RAV is shown on lines 1 to 7. The opening value of the RAV (line 1) is equal to the closing value of the RAV under our one year control final proposals. The different elements of capital expenditure (lines 2-3) are as follows:

- new capital expenditure (line 2); and
- 50 per cent of new replacement expenditure (line 3).

1.3. These elements are added to the opening RAV, and the allowed level of depreciation (line 4) is subtracted from it to give a closing asset value (line 5). The closing value in any year then becomes the next year's opening value.

1.4. The present value of the closing RAV in 2007-08 is shown in line 6. The present value movement in the RAV is then derived by subtracting the present value of the closing RAV from the opening RAV (line 7). Present value calculations involve discounting values by the vanilla WACC of 4.84 per cent.

1.5. The allowed levels of costs and associated items are shown in lines 8 to 18. Operating costs include:

- operating expenditure including ongoing pensions costs but excluding shrinkage, which has been considered separately (line 8);
- shrinkage allowances which for our updated proposals base case are assumed to be equal to those underlying our one year control final proposals (line 9);
- funding of pensions deficits (line 10); and
- 50 per cent of new replacement expenditure (line 11).

1.6. Our proposed allowances for corporation tax are set out on line 12. The cash allowance for capital expenditure in each year is the sum of lines 13 and 14, being the return on the RAV plus the depreciation allowance. This is equal to the sum of lines 2, 3 and 7.

1.7. Line 15 shows the additional income earned or penalty incurred by the company under the information quality incentive. Line 16 represents the portion of the capital expenditure allowance which is disallowed under the rolling incentive from 2002-07, where the companies do not receive allowances for five years. Finally, line 17 is the allowance for under-recoveries from the 2002-07 control (Pot 3 capital expenditure and pensions) and under-recovery of tax from the 2007-08 control. Line 18 is the sum of lines 8-17.

1.8. The total price control revenue is shown in lines 19-22. Line 19 is equal to line 18, and lines 20 and 21 are estimated non-controllable costs, being the NTS pension charge, rates and the licence fee. Line 22 is the sum of lines 19 to 21, and is the total price control revenue allowance. Line 23 is the equivalent for the 2007-08 control, and line 24 shows the percentage change in total allowed costs.

Table A17.1 - National Grid Gas - East of England price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	2,182.4	2,186.3	2,189.2	2,197.9	2,211.7	2,193.5
2	Total capital expenditure	34.8	30.2	36.1	40.1	44.9	37.2
3	Replacement expenditure added to RAV	47.1	51.3	51.6	53.3	53.7	51.4
4	Depreciation	-78.0	-78.5	-79.0	-79.6	-80.3	-79.1
5	Closing asset value	2,186.3	2,189.2	2,197.9	2,211.7	2,230.0	2,203.0
6	Present value of opening/closing RAV (at vanilla WACC of 4.84%)	2,085.3	2,088.1	2,096.4	2,109.5	2,127.0	2,101.2
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	99.4	100.5	95.1	90.5	86.7	94.5
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	98.0	96.0	93.7	91.2	90.5	93.9
9	Shrinkage allowance	14.2	14.2	14.2	14.2	14.2	14.2
10	Pension deficit funding	1.0	1.0	1.0	1.0	0.9	1.0
11	Expensed repex allowance	47.1	51.3	51.6	53.3	53.7	51.4
12	Tax allowance	7.0	7.6	9.1	9.5	11.2	8.9
13	Return on RAV	103.3	103.5	103.8	104.3	105.1	104.0
14	Depreciation	78.0	78.5	79.0	79.6	80.3	79.1
15	IQI incentive allowance	1.5	1.5	1.6	1.7	1.7	1.6
16	Incentive allowance / (disallowance) under capex roller from 2002-07	-6.1	-5.0	-3.6	-1.4	0.0	-3.2
17	Under-recoveries from 2002-07 control	6.1	6.1	6.1	6.1	6.1	6.1
18	Total of allowed costs	350.1	354.7	356.3	359.5	363.6	356.8
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	350.1	354.7	356.3	359.5	363.6	356.8
20	NTS charge for pensions	4.4	4.3	4.2	4.1	4.0	4.2
21	Non-controllable costs	59.3	59.3	59.3	59.3	59.3	59.3
22	Price control revenue	413.8	418.3	419.9	423.0	426.9	420.4
23	Price Control Revenue for 2007-08	427.2					
24	Change as %age	-3.1%	1.1%	0.4%	0.7%	0.9%	-0.5%

Table A17.2 - National Grid Gas - London price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,241.1	1,307.4	1,359.6	1,385.1	1,415.9	1,341.8
2	Total capital expenditure	59.7	53.0	26.2	31.5	39.1	41.9
3	Replacement expenditure added to RAV	50.4	44.7	46.3	47.1	44.8	46.7
4	Depreciation	-43.8	-45.5	-47.0	-47.8	-48.8	-46.6
5	Closing asset value	1,307.4	1,359.6	1,385.1	1,415.9	1,450.9	1,383.8
6	Present value of opening/closing RAV (at vanilla WACC of 4.84%)	1,247.0	1,296.8	1,321.1	1,350.5	1,383.9	1,319.9
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	-6.1	10.9	39.4	35.5	32.7	22.5
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	75.2	72.0	70.9	69.4	68.4	71.2
9	Shrinkage allowance	8.3	8.3	8.3	8.3	8.3	8.3
10	Pension deficit funding	0.6	0.6	0.6	0.6	0.5	0.6
11	Expensed repex allowance	50.4	44.7	46.3	47.1	44.8	46.7
12	Tax allowance	0.0	0.0	0.0	0.0	0.0	0.0
13	Return on RAV	60.3	63.1	64.9	66.2	67.8	64.5
14	Depreciation	43.8	45.5	47.0	47.8	48.8	46.6
15	IQI incentive allowance	1.4	1.2	1.3	1.4	1.2	1.3
16	Incentive allowance / (disallowance) under capex roller from 2002-07	-5.2	-4.4	-3.2	-1.5	0.0	-2.9
17	Under-recoveries from 2002-07 control	4.1	4.2	4.2	4.2	4.2	4.1
18	Total of allowed costs	239.0	235.2	240.2	243.5	244.1	240.4
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	239.0	235.2	240.2	243.5	244.1	240.4
20	NTS charge for pensions	2.6	2.5	2.5	2.4	2.3	2.5
21	Non-controllable costs	33.1	33.1	33.1	33.1	33.1	33.1
22	Price control revenue	274.6	270.8	275.7	279.0	279.5	275.9
23	Price Control Revenue for 2007-08	245.1					
24	Change as %age	12.1%	-1.4%	1.8%	1.2%	0.2%	4.1%

Table A17.3 - National Grid Gas - North West price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,410.2	1,433.8	1,456.0	1,481.4	1,506.8	1,457.6
2	Total capital expenditure	25.0	25.1	29.9	30.7	28.5	27.9
3	Replacement expenditure added to RAV	47.9	47.4	46.5	46.6	44.1	46.5
4	Depreciation	-49.4	-50.2	-51.0	-51.9	-52.8	-51.1
5	Closing asset value	1,433.8	1,456.0	1,481.4	1,506.8	1,526.5	1,480.9
6	Present value of opening/closing RAV (at vanilla WACC of 4.84%)	1,367.5	1,388.8	1,412.9	1,437.2	1,456.0	1,412.5
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	43.7	46.1	44.1	45.3	52.0	46.2
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	78.8	78.1	76.8	74.7	74.9	76.7
9	Shrinkage allowance	11.2	11.2	11.2	11.2	11.2	11.2
10	Pension deficit funding	0.7	0.7	0.7	0.7	0.6	0.7
11	Expensed repex allowance	47.9	47.4	46.5	46.6	44.1	46.5
12	Tax allowance	0.0	0.0	0.0	0.0	0.2	0.0
13	Return on RAV	67.3	68.3	69.5	70.7	71.7	69.5
14	Depreciation	49.4	50.2	51.0	51.9	52.8	51.1
15	IQI incentive allowance	1.4	1.4	1.4	1.5	1.4	1.4
16	Incentive allowance / (disallowance) under capex roller from 2002-07	-4.7	-4.4	-3.5	-1.6	0.0	-2.9
17	Under-recoveries from 2002-07 control	3.2	3.2	3.2	3.2	3.2	3.2
18	Total of allowed costs	255.3	256.2	256.8	258.9	260.2	257.5
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	255.3	256.2	256.8	258.9	260.2	257.5
20	NTS charge for pensions	3.0	3.0	2.9	2.8	2.8	2.9
21	Non-controllable costs	31.7	31.7	31.7	31.7	31.7	31.7
22	Price control revenue	290.1	290.8	291.4	293.3	294.6	292.0
23	Price Control Revenue for 2007-08	285.5					
24	Change as %age	1.6%	0.3%	0.2%	0.7%	0.4%	0.8%

Table A17.4 - National Grid Gas - West Midlands price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,089.7	1,106.1	1,117.4	1,129.0	1,143.5	1,117.2
2	Total capital expenditure	17.6	14.5	16.9	20.5	18.2	17.5
3	Replacement expenditure added to RAV	37.4	35.9	34.4	34.1	32.9	34.9
4	Depreciation	-38.6	-39.1	-39.6	-40.1	-40.7	-39.6
5	Closing asset value	1,106.1	1,117.4	1,129.0	1,143.5	1,154.0	1,130.0
6	Present value of opening/closing RAV (at vanilla WACC of 4.84%)	1,055.0	1,065.8	1,076.9	1,090.7	1,100.7	1,077.8
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	35.5	41.3	41.5	39.2	43.9	40.3
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	58.2	67.2	56.5	54.6	53.8	58.1
9	Shrinkage allowance	8.7	8.7	8.7	8.7	8.7	8.7
10	Pension deficit funding	0.5	0.5	0.5	0.5	0.5	0.5
11	Expensed repex allowance	37.4	35.9	34.4	34.1	32.9	34.9
12	Tax allowance	0.0	0.0	0.6	2.4	3.9	1.4
13	Return on RAV	51.9	52.6	53.1	53.7	54.3	53.1
14	Depreciation	38.6	39.1	39.6	40.1	40.7	39.6
15	IQI incentive allowance	1.1	1.0	1.0	1.1	1.0	1.0
16	Incentive allowance / (disallowance) under capex roller from 2002-07	-3.1	-2.4	-1.7	-0.7	0.0	-1.6
17	Under-recoveries from 2002-07 control	3.4	3.4	3.4	3.4	3.4	3.4
18	Total of allowed costs	196.6	206.1	196.1	198.0	199.1	199.2
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	196.6	206.1	196.1	198.0	199.1	199.2
20	NTS charge for pensions	2.2	2.1	2.1	2.0	2.0	2.1
21	Non-controllable costs	24.7	24.7	24.7	24.7	24.7	24.7
22	Price control revenue	223.6	233.0	222.9	224.8	225.9	226.0
23	Price Control Revenue for 2007-08	217.8					
24	Change as %age	2.7%	4.2%	-4.3%	0.8%	0.5%	1.2%

Table A17.5 - Northern Gas Networks - Northern price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,340.1	1,375.3	1,416.6	1,433.6	1,479.3	1,409.0
2	Total capital expenditure	43.8	39.7	29.3	58.6	44.1	43.1
3	Replacement expenditure added to RAV	38.3	49.5	36.9	37.1	37.2	39.8
4	Depreciation	-46.9	-47.9	-49.2	-49.9	-51.2	-49.0
5	Closing asset value	1,375.3	1,416.6	1,433.6	1,479.3	1,509.4	1,442.8
6	Present value of opening/closing RAV (at vanilla WACC of 4.84%)	1,311.8	1,351.1	1,367.3	1,411.0	1,439.7	1,376.2
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	29.0	24.8	50.4	23.1	40.6	33.6
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	74.9	76.0	75.4	75.1	74.2	75.1
9	Shrinkage allowance	10.7	10.7	10.7	10.7	10.7	10.7
10	Pension deficit funding	3.4	3.4	3.4	3.4	3.4	3.4
11	Expensed repex allowance	38.3	49.5	36.9	37.1	37.2	39.8
12	Tax allowance	0.8	0.0	0.3	3.3	4.1	1.7
13	Return on RAV	64.2	66.0	67.4	68.9	70.7	67.4
14	Depreciation	46.9	47.9	49.2	49.9	51.2	49.0
15	IQI incentive allowance	1.0	1.2	0.9	0.9	0.9	1.0
16	Incentive allowance / (disallowance) under capex roller from 2002-07	-2.9	-2.3	-1.8	-0.8	0.0	-1.6
17	Under-recoveries from 2002-07 control	3.4	3.5	3.5	3.5	3.5	3.5
18	Total of allowed costs	240.8	256.0	245.9	251.9	255.8	250.1
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	240.8	256.0	245.9	251.9	255.8	250.1
20	NTS charge for pensions	2.8	2.8	2.7	2.6	2.6	2.7
21	Non-controllable costs	30.9	30.9	30.9	30.9	30.9	30.9
22	Price control revenue	274.5	289.6	279.5	285.5	289.3	283.7
23	Price Control Revenue for 2007-08	273.5					
24	Change as %age	0.4%	5.5%	-3.5%	2.1%	1.3%	1.2%

Table A17.6 - Scotia Gas Networks - Scotland price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	973.2	1,020.1	1,047.4	1,076.3	1,092.9	1,042.0
2	Total capital expenditure	53.7	35.1	37.7	26.3	32.7	37.1
3	Replacement expenditure added to RAV	25.6	26.0	25.7	25.8	26.4	25.9
4	Depreciation	-32.4	-33.7	-34.6	-35.5	-36.2	-34.5
5	Closing asset value	1,020.1	1,047.4	1,076.3	1,092.9	1,115.8	1,070.5
6	Present value of opening/closing RAV (at vanilla WACC of 4.84%)	972.9	999.0	1,026.5	1,042.4	1,064.2	1,021.0
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	0.3	21.5	21.4	34.7	29.4	21.4
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	65.3	63.7	64.0	63.0	61.8	63.6
9	Shrinkage allowance	6.3	6.3	6.3	6.3	6.3	6.3
10	Pension deficit funding	3.8	3.7	3.6	3.5	3.4	3.6
11	Expensed repex allowance	25.6	26.0	25.7	25.8	26.4	25.9
12	Tax allowance	0.0	0.0	0.0	0.0	0.0	0.0
13	Return on RAV	47.1	48.9	50.2	51.3	52.2	50.0
14	Depreciation	32.4	33.7	34.6	35.5	36.2	34.5
15	IQI incentive allowance	0.1	0.1	0.1	0.1	0.1	0.1
16	Incentive allowance / (disallowance) under capex roller from 2002-07	-6.6	-6.1	-3.9	-1.4	0.0	-3.6
17	Under-recoveries from 2002-07 control	1.9	1.8	1.8	1.8	1.8	1.8
18	Total of allowed costs	176.0	178.2	182.4	186.0	188.3	182.2
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	176.0	178.2	182.4	186.0	188.3	182.2
20	NTS charge for pensions	2.0	1.9	1.9	1.8	1.8	1.9
21	Non-controllable costs	15.6	15.6	15.6	15.6	15.6	15.6
22	Price control revenue	193.5	195.6	199.9	203.4	205.6	199.6
23	Price Control Revenue for 2007-08	194.3					
24	Change as %age	-0.4%	1.1%	2.2%	1.8%	1.1%	0.9%

Table A17.7 - Scotia Gas Networks - Southern price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	2,244.5	2,316.9	2,394.9	2,457.4	2,509.5	2,384.7
2	Total capital expenditure	84.1	82.7	76.7	67.7	53.7	73.0
3	Replacement expenditure added to RAV	66.6	75.7	68.5	69.0	69.9	69.9
4	Depreciation	-78.3	-80.4	-82.7	-84.6	-86.4	-82.5
5	Closing asset value	2,316.9	2,394.9	2,457.4	2,509.5	2,546.7	2,445.1
6	Present value of opening/closing RAV (at vanilla WACC of 4.84%)	2,209.9	2,284.3	2,343.9	2,393.6	2,429.1	2,332.1
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	35.4	33.4	52.3	65.4	82.4	53.8
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	118.0	115.0	113.2	111.7	110.1	113.6
9	Shrinkage allowance	16.8	16.8	16.8	16.8	16.8	16.8
10	Pension deficit funding	8.8	8.5	8.3	8.1	7.9	8.3
11	Expensed repex allowance	66.6	75.7	68.5	69.0	69.9	69.9
12	Tax allowance	0.0	0.0	0.0	0.0	0.0	0.0
13	Return on RAV	107.9	111.4	114.8	117.5	119.6	114.2
14	Depreciation	78.3	80.4	82.7	84.6	86.4	82.5
15	IQI incentive allowance	0.2	0.2	0.2	0.2	0.2	0.2
16	Incentive allowance / (disallowance) under capex roller from 2002-07	-6.7	-5.5	-4.7	-2.6	0.0	-3.9
17	Under-recoveries from 2002-07 control	2.4	2.5	2.5	2.5	2.5	2.5
18	Total of allowed costs	392.4	405.1	402.2	407.7	413.3	404.2
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	392.4	405.1	402.2	407.7	413.3	404.2
20	NTS charge for pensions	4.5	4.4	4.3	4.2	4.1	4.3
21	Non-controllable costs	51.4	51.4	51.4	51.4	51.4	51.4
22	Price control revenue	448.3	460.9	457.9	463.3	468.8	459.9
23	Price Control Revenue for 2007-08	432.4					
24	Change as %age	3.7%	2.8%	-0.6%	1.2%	1.2%	2.1%

Table A17.8 - Wales & West Utilities - Wales & West price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,235.0	1,282.3	1,333.0	1,369.9	1,406.5	1,325.3
2	Total capital expenditure	56.4	55.9	45.6	46.3	43.6	49.6
3	Replacement expenditure added to RAV	33.1	38.4	36.3	36.3	35.6	35.9
4	Depreciation	-42.2	-43.5	-45.0	-46.1	-47.3	-44.8
5	Closing asset value	1,282.3	1,333.0	1,369.9	1,406.5	1,438.3	1,366.0
6	Present value of opening/closing RAV (at vanilla WACC of 4.84%)	1,223.1	1,271.4	1,306.7	1,341.5	1,371.9	1,302.9
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	12.2	11.2	27.0	29.1	35.4	23.0
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	78.1	78.2	76.0	74.4	72.6	75.9
9	Shrinkage allowance	11.9	11.9	11.9	11.9	11.9	11.9
10	Pension deficit funding	5.1	4.9	4.8	4.7	4.6	4.8
11	Expensed repex allowance	33.1	38.4	36.3	36.3	35.6	35.9
12	Tax allowance	0.0	0.0	0.0	0.0	0.0	0.0
13	Return on RAV	59.5	61.8	63.9	65.7	67.3	63.6
14	Depreciation	42.2	43.5	45.0	46.1	47.3	44.8
15	IQI incentive allowance	0.2	0.2	0.2	0.2	0.2	0.2
16	Incentive allowance / (disallowance) under capex roller from 2002-07	-5.1	-3.9	-2.8	-1.1	0.0	-2.6
17	Under-recoveries from 2002-07 control	3.3	3.2	3.2	3.2	3.2	3.2
18	Total of allowed costs	228.2	238.2	238.4	241.3	242.6	237.7
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	228.2	238.2	238.4	241.3	242.6	237.7
20	NTS charge for pensions	2.7	2.6	2.6	2.5	2.5	2.6
21	Non-controllable costs	22.3	22.3	22.3	22.3	22.3	22.3
22	Price control revenue	253.1	263.1	263.2	266.0	267.3	262.6
23	Price Control Revenue for 2007-08	252.0					
24	Change as %age	0.5%	4.0%	0.0%	1.1%	0.5%	1.4%

Appendix 18 – Impact of proposals

1.1. The price control allowances represent the maximum revenue that the GDNs can collect via gas transportation charges (primarily use of system charges and customer charges) under our baseline assumptions. Other revenue streams such as connections contributions, metering and meter reading are not affected.

1.2. The precise impact of these proposals on charges to different types of customers will depend on a number of additional factors, including:

- the rate of inflation;
- changes in the level of business rates, due to be re-evaluated in 2010;
- the application of a k factor as a result of under or over-recoveries;
- potential changes to the structure of charges;
- the gains or losses that may be made by GDNs due to specific incentive schemes;
- GDNs' allowance under the shrinkage incentive, which is affected by the outturn gas price index;
- the impact of additional allowances under the loss of meter work revenue driver; and
- the impact of the innovation funding incentive (IFI).

1.3. We do not normally include incentive gains or losses in our assessment of future charges, because we cannot predict how companies perform against them, it is appropriate to estimate their impact as zero. However, these last three factors are not symmetric incentives, and so it is reasonable to expect them to be higher than zero, although they are contingent on factors that prevent us from accurately predicting the out-turn. Only the shrinkage incentive allowance is currently included in our base case allowances, and it is simply carried forward at the same level as the one year control so that it doesn't obscure the impact of our proposals. We set out in chapter 10 the overall impact of:

- updating the shrinkage allowance for changes in the form of the incentive and the latest gas prices;
- the cost of the revenue driver if the GDNs lose meter work at the rate they have forecast; and
- the cost of the IFI if taken up in full by the GDNs.

1.4. Additionally, the impact of inflation is not included in our baseline allowed revenue figures, which are presented in 2005-06 prices.

1.5. We appreciate that shippers and consumer groups are keen to understand the overall change in charges, which is the cumulative effect of all factors. In our one year proposals, we published a table showing the likely change in charges to customers between 2006-07 and 2007-08.

1.6. Below, we set out the likely impact of our updated proposals for the main control on GDNs' allowed revenues once inflation and changes to allowances for shrinkage, the loss of meter work revenue driver and the IFI are taken into account. We assume that GDNs do not make gains or losses under other incentives and that they recover their allowed revenue in each year with no adjustments for over or under-recoveries.

1.7. Table A18.1 shows the results in terms of forecast values for the licence terms DNZ (baseline allowance), DNSh (shrinkage) and DNF (non controllables) in 2007-08 and 2012-13, the final year of the price control period. We compare the 2007-08 forecast with the figures published in our one year control final proposals; the differences between the two values for this year are due to updated information on inflation and shrinkage gas prices.

1.8. We have also included a figure to show the impact on a typical domestic consumer (this cannot be simply derived by dividing total allowed revenue by number of customers, since each GDN has a number of large industrial users that use much more gas than a domestic customer). This is calculated as follows:

- starting with current charges for an average domestic customer, calculate forecast charges in 2007-08 for each GDN, assuming that GDNs recover their allowed revenue during that year; and
- apply our per cent increase figure, calculated from adjusted allowed revenues, to the 2007-08 charges to give a forecast customer charge for 2012-13. This represents the amount that a typical domestic customer might expect to pay to cover gas distribution charges in this year.

1.9. This calculation is not dependent on the proportion of the total bill that relates to gas distribution charges, which varies with gas prices.

Table A18.1 - Changes in allowed revenue from 2007-08 to 2012-13 (nominal prices, unless stated)[41]

£m	2007-08 per one year control final proposals	2007-08 latest view	2012-13 latest view	Change from 2007-08 to 2012-13 latest views
Baseline allowance (2005-06 prices) less shrinkage	1,945.8	N/A	2,077.9	132.1
Shrinkage assumed within baseline allowance (2005-06 prices)	88.1	N/A	88.1	0.0
Non controllables assumed in total allowances (2005-06 prices)	293.8	N/A	292.0	-1.8
Total allowances (2005-06 prices)	2,327.7	N/A	2,458.0	130.3

Baseline allowance less shrinkage, adjusted for inflation (DNZ)	2,045.9	2,070.1	2,501.2	431.0
Shrinkage, after adjustment for price, volume and inflation (DNSh)	92.7	38.4	43.2	4.8
Total non controllables, adjusted for inflation (DNF)	308.9	315.8	355.2	39.4
Additional revenue under loss of meter work revenue driver, adjusted for	0.0	0.0	27.7	27.7
Additional revenue under IFI, adjusted for inflation	0.0	0.0	12.0	12.0
Total revenue	2,447.4	2,424.4	2,939.2	514.8
Average revenue per domestic customer	£94.26	£93.58	£113.48	£19.90

1.10. The change in forecast revenues shown above is equivalent to a 4.4 per cent average annual rise. This is equal to the 1.3 per cent average annual increase presented in previous chapters + 2.5 per cent pa inflation + average annual impact of loss of meter work revenue of 0.4 per cent + average annual impact of IFI revenue of 0.2 per cent.

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[41] Figures in the first column may differ slightly from those published in our one year control final proposals due to rounding.

Revised shrinkage allowances are based on estimated average gas prices for 2007, taken from Heren at 29 August 2007, and our forecast volumes. The prices are lower than those underlying our one year control final proposals. Gas prices are assumed to rise by inflation in the remaining years of the price control.

Inflation adjustments for shrinkage and non controllables reflect actual inflation between 2005-06 and 2006-07. We assume inflation of 3 per cent in 2007-08 and 2.5 per cent thereafter. For the baseline allowance we calculate 2006-07 and 2007-08 inflation according to the formula in the DNZ licence term and assume 2.5 per cent annual inflation thereafter.

1.11. The difference between the shrinkage numbers underlying our base case allowances and our updated shrinkage forecasts has a negligible impact on the forecast change in revenues as we have assumed the gas price remains constant in real terms between 2007-08 and 2012-13. However, our revised estimate of the cost of shrinkage means that 2007-08 charges should be around 2 per cent lower than they would otherwise have been.

1.12. In our final proposals for the main control we expect to update this table to include more accurate information on likely charges to customers in 2008-09.

1.13. We would welcome respondents' views on the most helpful way to present the impact of our proposals on customers.