

## **Gas Distribution Price Control Review Second Consultation Document**

### **A Response by National Grid Gas**

**August 2006**

1. This is National Grid's response to the Gas Distribution Price Control Review Second Consultation Document published in July 2006. The consultation provides a clear and balanced view of the issues which we expect to be dealt with as part of the extension and main price control reviews.
2. Our response is in two sections. The first provides a summary of our views on the extension year, whilst the second provides answers to the specific questions posed by Ofgem in the consultation document.

#### **Section One: Our views on the extension year**

##### **Principles for the extension year review**

3. In order to achieve an acceptable outcome for the extension year review, we recognise that Ofgem must balance a number of factors:
  - Enabling each GDN to finance its operations for 2007/08,
  - Protecting consumers from inefficiency and unnecessary price rises, and
  - Ensuring that the workload undertaken for a single year control is proportionate.
4. Therefore, we would not expect the outcome of the review to materially depart from the current price control settlement except where there is strong evidence that the balance between shareholders and customers, as established as part of the original settlement, has been overtaken by events.

##### **Starting position for the extension year**

5. Our starting point is that, over the period, we have experienced significant financial underperformance, with actual pre-tax returns consistently below 6% (before any restructuring costs) compared to the 6.25% pre-tax return used to set the control. This is despite substantially meeting underlying efficiency targets (achieved only by incurring those unfunded restructuring costs). Externally driven cost pressures such as insurance costs, gas prices and pensions costs, have meant that total operating expenditure has exceeded allowances. The

impact of overspends against capital allowances plus consistently mild weather have further exacerbated the financial position.

6. We contend that it would be inequitable for the extension year review to perpetuate current levels of financial performance. Having considered the consultation document, we are concerned that the current proposals would actually tilt the settlement even further against shareholders.

### **Building blocks for the extension year**

#### *Operating Expenditure*

7. Ofgem face the task of setting an equitable allowance without being able to carry out a full bottom up analysis of the operating costs on a GDN basis. Given the timescales available, and the limited impact that resetting a one year allowance for opex has for both customers and GDNs, we believe that the opex allowance for 2007/08 should be determined simply but transparently. We have already discussed the need to ensure that the overall outcome is balanced, and therefore the allowances set for 2007/08 will need to reflect the impact of:
  - Gas price increases on shrinkage costs,
  - Changes in pension valuations on the level of payments into the scheme, and
  - Perceptions of terrorism risks on insurance premiums.
8. We agree that extrapolation of the opex allowances set at the last review may lock outdated cost allocations into customer prices and we therefore propose that allowances for 2007/08 are premised on the actual split of costs by GDN reported for 2004/05. The use of 2004/5 actuals will mitigate Ofgem's concerns relating to atypical costs arising as a result of network sales as this was the last year of common ownership and operation.

#### *Past Investment*

9. A cornerstone of the extension year review will be the settling of the Regulatory Asset Value (RAV) roll forward by establishing the correct opening balance and building in the efficient and necessary investment expenditure undertaken during this review period. It is appropriate therefore that our investment performance and plans are reviewed in detail at this stage and we welcome the engagement shown by Ofgem and their consultants in the process to date.
10. Regulatory disallowance of past investment would clearly be a serious and largely unprecedented move, and one with the potential to materially increase regulatory uncertainty and perceived risk faced by investors. This is particularly true for gas distribution networks

where the vast majority of investment is non-discretionary, driven as it is by our obligation to react to customers' demands and maintain a safe network. It is therefore important that treatment of past investment is not only objective and transparent but also applied in a consistent manner. Given the monies at risk, a high burden of proof on any disallowance of past investment must be required as part of this process. Any methodology that is applied ex-post will also leave the licensee vulnerable to unfair 'with the benefit of hindsight' assessments and hence it is important that clear rules be established upfront.

11. We welcome Ofgem's intentions to reduce future ambiguity in this area by defining the rules of over and under spend to minimise the longer term perception of risk. However, we have concerns about some aspects of the principles proposed in the consultation and their potential application to past spend, not least the lack of alignment with previous guidance issued in this area by Ofgem.
12. Whilst we acknowledge that the underlying principle of rolling capex incentives is not new, as outlined in the Open Letter on Gas Distribution Price Controls (March 2004), the interpretation of spend that provides "significant benefits to consumers" most certainly is. It was our expectation that where expenditure could be demonstrated as efficient and having provided significant benefit to consumers, this would be allowed in full from the date incurred.
13. The consultation document now only proposes to apply this treatment to any variance in workload. This variation is then assessed at the unit price used to set the original control, and not the efficient cost as determined by Ofgem's consultants. Together, this results in much of our efficient and mandatory over-spend being treated as "Pot 2", with a loss of depreciation and financing for five years.
14. We consider this proposal inequitable. The 'whole life' pre tax return investors are being offered for necessary spend efficiently incurred is below 4%, versus the 6.25% accepted in 2002. If the model is implemented as currently proposed, GDNs will be penalised by significantly more than could have been anticipated at the last price control review, or following receipt of the Open Letter, for carrying out work efficiently in accordance with their obligations.

#### *Rolling incentives*

15. It is worth considering what the incentive properties of the proposed treatment would have been in the current period had we known in advance that it would apply. We would have been incentivised to under invest, even though the majority of our investment is non-discretionary and in consumers' interests; we would have been incentivised to adopt short-

term solutions at the expense of more efficient longer-term solutions; and we would have been incentivised to reopen the control with Ofgem between reviews.

16. Whilst we consider that further discussion on rolling incentives should be limited to the main review, we note that any such mechanism could also be applied at the extension review. We believe the incentive properties described above argue against implementing them either as part of the extension or the main review, as the practicalities of ensuring that any such scheme does not distort incentives is likely to outweigh the possible benefits.

#### *Rate of return*

17. A move to a post-tax rate of return at the extension year would represent a significant financial detriment to GDNs within any overall settlement. Whilst we acknowledge that pre-tax treatment has been a benefit to GDNs in the past (as they have been able to set repex off against tax), we believe the tax impact was well understood at the time of the 2002 review and that Ofgem took it into account fully when crafting the overall balance between shareholders and consumers at that time
18. We remain of the view that the existing 6.25% pre-tax return should be rolled forward for the extension year. The current timetable does not allow for a full and proper review of all the rate of return parameters, including the relative risks between GDNs and transmission or electricity distribution. To simply move to a post tax approach or apply the outcome from the Transmission Price Control Review (TPCR), in the absence of this work would not be appropriate.

**Section Two: Answers to specific questions**

**Chapter Two: High level framework of the price controls**

***Question 1: Should Ofgem retain the form, structure and scope of the current price control during the one year control?***

19. We agree with the approach proposed by Ofgem to extend the current price control by one year and then set a further five-year control. In the interests of simplicity, and cognisant of maintaining a workload proportionate to a one year control, Ofgem should avoid making changes to the underlying regulatory framework unless evidence exists that the assumptions underpinning the current settlement are no longer valid.

***Question 2: Should Ofgem introduce a new revenue driver other than the volume driver and, if so, what variable should it be linked to?***

20. We note within the consultation that the issue of revenue drivers will be dealt with as part of the main review. We therefore assume that the Maximum Allowed Revenue (MAR) proposed as part of the extension year will effectively be fixed (subject to K and DNMRA adjustments) and not subject to a revenue driver.
21. Looking further ahead we believe that, where practical, revenue drivers in the price control should be aligned with our cost drivers. Under the current price control, revenues vary with throughput by 35%, whereas, in practice, less than 5% of our costs vary with throughput within year. This misalignment has had a substantial negative impact on GDNs over the current formula period given the consistently warmer than average weather and represents a disproportionate risk to their investors.
22. It would be possible to implement alternative revenue drivers, but these too are likely to suffer from issues of cost correlation. Whilst a capacity driver may appear attractive, associated complexities make it less practical. First, our analysis suggests that it is very difficult to establish a robust definition for additional capacity (actual capacity, 1 in 20 obligations, or booked capacity all having their own pros and cons). Second, the costs associated with an increment of capacity very much depend on the location and type i.e. domestic or industrial. Finally, in common with throughput, the variability in revenue is likely to be small.

23. A supply point related driver could be utilised, but again it is likely to result in small variations to the level of allowed revenue, again bringing into question whether the additional effort would be justified.
24. Our preference is for the retention of a volume driver but with the current 35% variability reduced to 5%, making it more reflective of the way our costs vary with changes in throughput.

***Question 3: What revenue and/or costs should be treated as excluded/de minimis/pass through? What principles should be used to classify revenues and/or costs as excluded/de minimis/pass through?***

25. In principle, we would support the following rationale for separating services:
- **Ordinary price control treatment** for those activities whose charges fall under Special Condition E2B, i.e. general transportation activities.
  - **Pass through** for costs where the GDN cannot exert significant control, such as Licence fees, and prescribed rates. On prescribed rates, we believe it would be efficient for the costs of appeals to be included as pass through, to provide some incentive to manage those costs where possible.
  - **Excluded services** for all other activities, i.e. permitted purposes or activities with specific Ofgem consent whose costs do not come under Special Condition E2B. Generally, this applies to activities where the costs cannot be readily separated from regulated services such as providing Emergency Services to Independent Gas Transporters (IGTs).
  - **De minimis** for activities that are neither a permitted purpose nor have specific Ofgem consents, and are capped at 2.5% of regulated turnover. This would include property sales of redundant operational sites.
26. Presently, income from the provision of metering services is treated as excluded service revenue. However, given the level of uncertainty surrounding metering workload going forward, we believe it would be more appropriate to assume zero income during the forthcoming period and to implement some form of revenue sharing mechanism on any such income earned by the funded emergency workforce. This would require careful definition but the intention would be to share the benefits of metering (and other) revenues between shareholders and consumers, the latter are already reaping the benefits of metering competition.

27. Currently SOMSA and other inter-transporter service agreements are treated as de minimis activities but are excluded from the 2.5% cap. We believe this treatment is appropriate, as the contracts are of sufficient magnitude that they impact upon the level of staff employed and the additional costs can be identified separately from the main activity of the GDN.
28. We note the comments raised within the consultation document in relation to one-off domestic connections. We look forward to discussing this further but would need to be persuaded that including the total costs of one-off connections within the price control is the right approach. In particular, we think that an additional revenue driving mechanism would be required.

***Question 4: Should Ofgem link some or all of allowed revenues to a price index other than RPI?***

29. We accept that RPI is a widely understood measure and, whilst not representative of the impact of inflation on the cost base of a GDN, we agree that it remains the appropriate basis upon which to index future revenues.
30. It is imperative however that, when setting the cost allowances, Ofgem build in realistic real price effects, including contractor rates and materials costs. In determining future frontier efficiency targets, containing cost increases within RPI will be a stretching efficiency challenge for utility companies.

***Question 5: Should Ofgem specify certain issues that could be the subject of a reopener and, if so, which issues?***

31. Risk mitigation in the form of cost re-openers is generally seen as a positive move from the perspective of investors. We note Ofgem's view that generic uncertainty mechanisms are not warranted given the variety of mechanisms that already exist. However, investors do regard the absence of mechanisms that correct for relevant changes in circumstance, such as the "Interim Determination of K" (IDOK) in water, as one reason why gas distribution is riskier than water distribution.
32. We believe that there are a small number of areas where potentially significant additional costs can reasonably be anticipated over the next five years, although the precise timing and scale is uncertain. In these cases, we believe that a commitment to allow pass through for clear auditable external costs and a focused re-opener for efficient additional internal costs represents an appropriate way forward. These areas include:

*Traffic Management Act (TMA)*

33. Any costs associated with the actual legislation, such as permits and an 'efficient level' of fines, should be funded as pass through. Costs incurred with respect to changes to working practices should be subject to a focused re-opener. Further detail on TMA can be found in our response to question seven of chapter three.

*Environmental Issues*

34. A test case relating to contamination at Bawtry is going through the courts at present. National Grid continues to contest any liability and believes it has a strong case. It is of course possible that the courts could ultimately find against National Grid, which may lead to a series of similar claims being made.

*Changes to working practices associated with HSE requirements – Management of Gas Escapes*

35. National Grid's obligations to respond to gas escapes in its role as Emergency Service Provider are defined in the Gas Safety (Management) Regulations (GSMR). If, as part of the ongoing discussions with the HSE in relation to compliance with the GSMR, we are required to incur significant costs in meeting more onerous timescales than current standard industry practice for resolving gas leaks, then our allowed revenues will need to be increased accordingly. To the extent that this issue is not resolved ahead of the setting of the main price control, a focused re-opener would ensure that any additional efficient costs are funded.

*Carbon Monoxide Detection*

36. GDNs currently respond to all public reports of gas escapes, including actual or suspected emissions of carbon monoxide (CO) from gas appliances. Where such gas escapes arise from pipework or appliances downstream of the emergency control valve, GDNs will make safe, by isolating either the appliances or the gas supply and advising the consumer to contact a CORGI-registered installer. GDNs do not currently carry out work to pro-actively identify the presence of CO, as they believe such work is outside the scope of current obligations. Were the HSE to identify or create an obligation to pro-actively identify or monitor for the presence of CO in properties, National Grid would need to seek additional funding for the required activity through a focused re-opener.

*Tax*

37. Changes are currently being introduced in relation to accounting standards within the UK, i.e. implementation of IFRS. To the extent that these changes materially alter the tax treatment faced by GDNs, we would expect such auditable costs to be passed through without re-opening the price control.

*NTS Exit and Interruption Reform*

38. We have not included NTS Exit and Interruption arrangements as part of this question as it is our expectation that these will be subject to a separate incentive scheme. Should this not be the case, provisions will need to be made for costs associated with these schemes.

**Chapter Three: High level framework of the price controls**

***Question 1: Is our approach to carrying out ex-post assessments of historical efficiency appropriate?***

39. In the case of retrospective assessment, it is essential that a transparent methodology, based upon clear pre-defined principles, be applied with absolute consistency. Whilst we acknowledge the level of work that Ofgem has committed to in completing their assessment, we are concerned with proposals that we believe extend significantly beyond previous guidance, in particular the Pot 2 treatment of expenditure over and above the allowance by the use of allowed rather than efficient unit cost for evaluating additional workload. We expand on this further in our response to question two.

*Establishing the correct opening balance*

40. We support Ofgem's proposal to roll forward the RAV taking into account actual and forecast expenditure for January 2001 to March 2008 as part of the extension year review. We note that Ofgem do not specifically reference the amendments required to update the April 2002 opening RAV to include realigned and shared assets. In the case of the realigned assets, the necessary adjustment reflects asset movements between price controls, which we assume will be incorporated. The shared assets refer to a correction required for central assets including, for example, our enduring back office systems. As these assets are now solely supporting the four networks retained by National Grid, these adjustments need to be incorporated into our RAV.

***Question 2: Is our proposed regulatory treatment of our conclusions on efficiency appropriate, transparent and practical?***

41. We have a number of concerns over the proposed approach. However, before commenting on the specific areas, it is worth reiterating our view on the principles through which the assessment should be applied:

- Prior to any assessment being undertaken, all parties must have clear sight of the principles and rules,
- The methodology by which these are applied must be objective, reflect practicalities and be transparent, and
- The principles and the methodology should be applied consistently, with clear substantiated evidence provided to justify the decision.

*Regulatory Precedent*

42. Regulatory disallowance of past investment is clearly a serious and largely unprecedented move, adding to regulatory uncertainty and the perceived risk faced by investors.

43. We acknowledge Ofgem's intention to reduce ambiguity by defining the rules of over and under spend. We are concerned however that the current proposal extends significantly beyond the principles outlined within the Open Letter on Gas Distribution Price Controls in March 2004. Whilst we acknowledge that the underlying principle is not new, we are alarmed at the interpretation of "significant benefits to consumers". Where expenditure could be demonstrated as having significant benefit to consumers, it was our expectation that this would be allowed in full from the date incurred.

44. Had we known this proposed treatment at the time of expenditure, as a minimum we would have engaged Ofgem further and our behaviour may have been different, with more short-term solutions adopted at the expense of longer-term efficiencies.

*Unit Cost Application*

45. We are further concerned that any workload evaluated as Pot 2 will be assessed at the allowed unit cost rather than the deemed efficient level. We consider this inequitable. Where Ofgem's consultants define an efficient unit cost, we firmly believe this should be applied in the RAV roll forward.

*Burden of Proof and Consistency*

46. From a practical perspective, it will be a challenge to apply the model as proposed objectively and consistently for the current price control period, given the lack of detail that exists as to the drivers and schemes underpinning the 2002 allowance. Neither is it clear how substitutability between projects in the original forecast and those actually delivered is to be considered. It is imperative that a high burden of proof is evidenced for all decisions in relation to historic investment.
47. We remain of the view that the overwhelming majority of our investment has been non-discretionary (both timing and location) and efficient, providing significant benefits to consumers, particularly in areas relating to new connections, additional capacity and replacement of services. If the model is implemented as currently proposed, GDNs will be effectively penalised for efficiently carrying out work in accordance with their obligations.
48. For the current price control, we believe that Pot 3 treatment should be applied to all non-discretionary, efficient expenditure, irrespective of the original allowance. Application of any Pot 2 should be limited to discretionary spend only that was not detailed within our plans as set out in the Open Letter.

***Question 3: Is our initial view on how to set capital and replacement expenditure allowances for 2007-08 appropriate?***

49. We recognise the level of work that Ofgem has undertaken in completing the assessment of capital and replacement expenditure and acknowledge the input the consultants' work will have into setting allowances for 2007-08. However, it is important that the allowances are based on a detailed review of 2007-08 forecasts and not on a simplistic extrapolation of past expenditure or allowances.

***Question 4: Which of our options is most appropriate for setting the operating expenditure allowance for 2007-08?***

50. The workload to establish opex allowances for 2007/08 must be proportionate to the scope of the deliverable, and so some form of extrapolation is practical. GDNs together have generally achieved the current allowance on an underlying level, (i.e. excluding external costs) and so we believe that this can be rolled forward to provide an appropriate basis for the allowance for 2007/08. In doing so however, Ofgem must reflect on two important factors:

- Adjusting this allowance for significant external factors that have developed since the 2001 Final Proposals, including the impact of gas price increases on shrinkage, changes in pension valuations on contribution levels and the perception of terrorism risks on insurance premiums, and
- Ensuring that no outdated cost allocations are locked into customer prices in different GDNs.

51. The consultation document also recognises that the allocation of expenditure both between NTS and Distribution, and individual gas distribution networks, at the time of price control separation has created a misallocation between licensees. The opportunity should be taken to correct for this now, as any misallocations to NTS will have been addressed through TPCR.

52. We note the two options outlined in the consultation to extrapolate based either on allowances or actual costs. Both of these options have merits however, given the above, we believe that a hybrid of the two may provide the most appropriate way forward.

*Option one: Extrapolation of Allowances*

53. At the time of separation in 2003, the Transco price control allowance was apportioned using a transaction model premised on an organisational structure that pre-dated the current price control period. A number of factors, such as the separation between NTS and Distribution and the decision to merge thirteen LDZs into eight networks, were imperfectly interpreted in the model. Furthermore, the RPI-3.7% efficiency target was applied to all networks irrespective of the headroom in the relative starting efficiency identified in the review process. Given the above, rolling forward the existing allowances with known inaccuracies will perpetuate relative price levels that reflect outdated cost allocations between classes of customer.

*Option two: Extrapolation of Actual Costs*

54. Option two proposes using actual costs as the basis to determine allowances for 2007/08, but remains undecided as to the appropriate base year. Whilst we agree that 2005/06 will have atypical costs in all networks, we do not believe this to be the case for 2004/05. In 2004/05, distribution activities were organised into eight separate networks with support of shared back office services, which were fully accounted for within the management accounts on the same basis as the previous year. Costs associated with preparation for network sales were accounted for separately against the transaction. As such, the 2004/05 network costs, i.e. the last full year of common ownership, structure and processes, are the mostly likely to represent similar levels of operating efficiency, particularly since for much of 2004/05 it was not clear which, if any, networks would be sold.

*A hybrid option*

55. An alternative method of determining opex allowances for 2007/08, whilst avoiding some of the issues that Ofgem has identified within the consultation, may be to use actual costs to determine a relative split, which can then be applied to existing allowance as follows:
- i. Determine an appropriate total allowance for all the GDNs based on the total 2006/7 allowances.
  - ii. Allocate this overall allowance between GDNs based on 2004/05 actuals in each GDN,
  - iii. Adjust for the misallocation that occurred at price control separation between NTS and Distribution,
  - iv. Roll forward at RPI to set 2007/08 underlying allowances for each GDN , given the productivity improvements the GDNs will need to deliver just to contain their opex, (excluding shrinkage, pensions and insurance) within the retail price index, and
  - v. Adjust each GDN allowance for pensions, shrinkage and insurance costs, which are externally driven factors impacting on network cost base above that assumed in the existing allowances.

***Question 5: Is our proposed approach for setting capital and replacement expenditure allowances for 2008-09 to 2012-13 appropriate?***

56. We support the proposal that the allowances for the main control should build upon the analysis completed for the extension year review and agree with the further work proposed within the second consultation. We have already discussed as part of our answer to question four in chapter two the need to ensure that cost allowances build in real price effects. This is especially important in the construction contractor and materials areas, where continuation of demand driven price inflation in excess of RPI is expected.
57. As the majority of our capex and repex workload is driven by legislative and regulatory commitments, and discharged through our asset management systems, policies and procedures, we support the assessment of these as part of the review. Ofgem should also recognise and fund discretionary spend that realises future efficiencies.

**Question 6: Is our proposed approach for setting operating expenditure allowances for 2008-09 to 2012-13 appropriate?**

58. We agree with the overall approach as set out in the consultation document of using a variety of methods and agree with Ofgem over the limitations concerning the number of comparators and the length of time GDNs have been in separate ownership.
59. In carrying out the assessment of operating cost allowances for 2008-2013, a difficult, but key activity will be the normalisation of costs between GDNs to take account of differential requirements including:
- Higher costs of operating in London, including higher contractor inflation over the period given influences such as the Olympics and Terminal 5;
  - The physical asset differences that drive differential costs for maintenance and other operational activities;
  - The requirement to fund the emergency service against differing levels of metering work that might be available;
  - A consistent approach to the identification of atypical cost/benefits; and
  - Ensuring a like-for-like comparison when comparing activity based analyses.
60. In carrying out the expert review of support costs it seems sensible that, in the case of National Grid, the work of TPCR is not duplicated but instead is updated for the additional year covered by GDPCR.

**Question 7: How should we deal with the uncertainty surrounding the level of costs associated with the Traffic Management Act?**

61. We have already stated as part of our response to question five in chapter two the need to ensure that an appropriate re-opener exists in relation to the Traffic Management Act, given the uncertainties surrounding the timetable and scope.
62. A pragmatic approach to dealing with these uncertainties would be to set an explicit allowance for the internal costs associated with its implementation and insert a re-opener for auditable external costs such as permits and fines. Such cost variations could be monitored and audited through the forthcoming cost reporting framework.
63. Although, as Ofgem are aware, National Grid continues to work through the National Joint Utilities Group to ensure any additional costs imposed on utility customers are fully justified,

we believe significant uncertainty will remain when the price control is set on the cost of implementing and complying with the new legislation. Current areas of uncertainty include:

- Establishing the cost/benefit case for the Act;
- The number of Highways Authorities who choose to introduce a permit scheme and the fees that they would set;
- The restrictions imposed upon working practices under these schemes; and
- The level of Fixed Penalty Notices imposed.

64. Furthermore, at least two subsequent tranches of the regulations are proposed, with obligations and costs currently unknown. It follows that simply making an allowance within the price control would entail a risk of either creating a windfall for the GDNs or leaving them significantly under-funded.

***Question 8: What are your view's on our principles for assessing GTMS replacement costs, SOMSA exit and ongoing system operation costs?***

65. The Gas Transportation Management System (GTMS) was built to facilitate the migration of twelve regional control centres to four area control centres in the mid 1990s. Much of the hardware involved is now obsolete, with the availability of spares becoming a significant operational risk. Even without the sale of the four networks in 2005, replacement would now be required and we have provided substantial evidence to this effect.

66. We note that Ofgem are concerned that monies may already have been allowed for this replacement, but we do not believe this to be the case. Whilst monies were allowed at the time of the last review for project Ulysses, this project delivered a revised suite of control systems for the NTS only, and not distribution. There is therefore no historic expenditure in relation to GTMS replacement to be disallowed.

*SOMSA costs*

67. We acknowledge that 'set up' costs associated with establishing separate network control centres should be a matter for shareholders and not recovered from consumers. In relation to ongoing system operation costs, we do not agree with Ofgem that these should be bounded by the costs incurred by National Grid pre-sale in perpetuity, as this is likely to encourage GDNs to organise so as to minimise the impact of this rule, rather than in the interests of the overall efficiency of operations.

68. There are also a number of changes on the horizon that will have an impact on system operations cost, including enhanced safeguards required to protect the physical assets and IS

defined as a Critical National Infrastructure (CNI). Government security services have continued to refine the guidance to operators of CNI following the recent terrorist attacks. We are currently working with the security services to review our current arrangements against their latest guidance and expect system operation costs associated with operation of the network and support to the systems and infrastructure to increase from those levels experienced pre-sale.

69. In the longer term, reliance on comparative regulation to determine an efficient level of operating cost, rather than a mini cap, seems a more sensible approach.

#### **Chapter Four: Outputs and incentives**

##### ***Question 1: Is Ofgem's initial view on how to update the mains replacement incentive mechanism for 2007-08 appropriate?***

70. We are pleased that Ofgem intend to update the Mains Replacement Incentive Mechanism (MRIM) for 2007/8 and agree that the work completed by Ofgem's consultants as part of the Business Plan Questionnaire (BPQ) process should feed into the review of the parameters. In particular, the matrix unit cost updates should be derived from efficient laid costs and prevailing market conditions. The decommissioning lengths should be taken from those provided in our latest submissions, based on HSE requirements and the mains risk model.
71. We believe Ofgem should extend the current mechanism to include additional, larger diameter categories as part of the extension year review. If this is not practical, Ofgem should ensure that the existing matrix unit cost incorporates the associated cost of the larger diameter bands, given the rise of anticipated work at these diameters.
72. We also believe that the mechanism should be extended to include service replacement. Again, if this is not practical, Ofgem should ensure an adequate fixed allowance is included based on forecast workload and current efficient unit costs.

##### ***Question 2: Is Ofgem's initial view on rolling incentives during the one year control appropriate?***

73. Given our concerns over rolling capex incentives set out in question six in this chapter, we do not believe that the extension year should be subject to rolling incentives on capex. We note, but do not understand, Ofgem's comments on the applicability of an opex rolling incentive at the extension year. The one year allowance will be based on some form of extrapolation.

The starting point for any rolling incentives should be detailed comparable assessments of either past or future opex efficiencies. These have not been undertaken as part of this review. Instead, a view of efficient opex should be taken afresh at the main review.

***Question 3: How should Ofgem determine shrinkage allowances? Should Ofgem adopt one of the options presented in this chapter or a different option?***

74. We support Ofgem's initial conclusion that option 1a (allowances based on a pre-defined index of market prices) would offer suitable price protection in relation to shrinkage prices going forward. We note that this would be similar to the scheme for NTS shrinkage, which is already functioning and utilising an index of market prices. Given that this mechanism is now in its second year of operation, it would appear to offer a good starting point for the detailed design of a scheme under the GDPCR, thus allowing implementation for the extension year review.
75. We are pleased that Ofgem does not appear to be supporting allowances premised on benchmarking the GDNs' lowest cost, which would imply that the gas transporters as a community were unable to cover the cost of shrinkage gas and hence that shareholders would be required to subsidise the purchase of shrinkage gas each year.
76. Option two has merit if the shippers were able to procure shrinkage gas at a lower price than the GDNs, presumably by exploiting the economy of scale of their purchasing functions or superior market information. We would be interested to see a comparison over time of the prices achieved by shippers compared to those achieved by gas transporters, but we agree it is not feasible to implement such changes quickly.
77. We note Ofgem's comments in relation to Reconciliation by Difference (RbD). The proposed arrangements are closer to those in electricity and hence consideration of the electricity market may provide an estimate of the costs involved. In the recent RbD consultation, National Grid took the view that RbD remains a cost effective and fit for purpose approach, and at the Distribution Workstream meeting on 27 July, Ofgem expressed the view that RbD remains the most appropriate means of reconciliation. We agree with this assessment.

***Question 4: Should Ofgem carry out any further work on incentives as part of the one year control review, other than that set out in paragraphs 4.1 to 4.23?***

78. The work undertaken to deliver the one year extension to the current price control must be proportionate to the outcome, with assumptions only re-visited where good evidence exists

that they are no longer valid. We continue to believe that wide ranging changes to the current overall incentive regime are not necessary at this stage in the process.

***Question 5: Should the interruptions and NTS offtake incentives on the GDNs be part of the overall RPI-X price control or separate incentives with caps, collars and sharing factors? How should the price risk for each of these incentives be addressed?***

79. In our view, incentives in relation to interruptions and NTS exit capacity should remain outside the main RPI –X control. Clearly, as these schemes are not yet defined, and there will be little or no experience of how they will operate from a distribution perspective ahead of the setting of the main price control, there must be a significant risk of unexpected results.
80. By including the schemes within the main price control, GDNs would be exposed to this risk without the protection afforded by caps and collars of an incentive scheme. Furthermore, as the exit capacity is generally cheaper in the north, a different level of risk would be introduced into each GDN. An unexpected outcome on the incentive schemes could significantly skew the comparative performance of the GDNs, with some seeing negligible impact and others far greater, if included within the overall allowance.
81. When considering the price risk associated with NTS exit capacity, we remain concerned that, under the transitional arrangements GDNs carry the price risk as they will commit to purchase on indicative prices but the incentive scheme will settle on outturn prices. Whilst we welcome the setting of an absolute limit on exposure in this area, we believe that ultimately the price risk should not sit with the GDNs.

***Question 6: Is it appropriate to adopt rolling incentives and an information quality incentive mechanism for capital expenditure for gas distribution? If so, what should be the features of the incentives?***

82. Ofgem offer two alternative capex rolling regimes distinguished only by the level of ex-post assessment. We have serious concerns regarding the implementation of rolling capex incentives as part of the main price control review. Whilst in principle, their introduction might incentivise GDNs to spend appropriately, we believe the following elements are required to ensure successful implementation:

- A stable and known requirement of spend, and / or
- Accurate and reflective revenue drivers, and

- A relatively small potential for interaction between opex and capex, or similar incentive regimes for each.
83. Our capex volumes have not been stable. The vast majority of our capex volume is non-discretionary, driven by our statutory supply and safety obligations and subject to significant year on year variation. Partly as a result of this volume instability, we find it most efficient to procure this workload from contractor markets, which introduces a market price risk. As we have seen over the current price control period, the combined impact on capex can be variable. In particular, the accuracy and stability of forecasts for the final years of the control period is likely to be limited.
84. Revenue drivers for large parts of our capex (LTS, IS and general reinforcement) are difficult to construct as the cost is dependent on the details of the specific schemes required, although we acknowledge that it may be possible to implement a suitable driver for connections. Without a suitable revenue driver to address the likely volatility in forecasts, there is a significant risk of windfall gains for shareholders or consumers.
85. Rolling capex incentives cannot differentiate between efficient spend, deferment, or in the worst-case, avoidance. GDNs are incentivised to overstate capex requirements as part of the review and then underspend against the allowances set, even where that capex is required to meet consumers' requirements. These perverse incentives are only partially dealt with by the information quality incentive which Ofgem discuss.
86. We believe that the traditional five year ex-post approach, characterised by a RAV true up based on an assessment of actual efficient spend at the start of any review, remains the most appropriate vehicle for incentivising investment expenditure of GDNs. It places strong incentives on beating forecasts in the earlier years of the investment plan - when forecasts should be more certain - and weaker incentives towards the end of the plan when uncertainty begins to mount. If rolling capex incentives were to be retained, we would propose that the three pot model is retained but that the period for which the GDN is exposed to any over or under-spend is subject to a shorter duration than 5 years currently suggested.
87. With specific reference to the information quality incentive, we support Ofgem's proposal as long as the incentive is balanced and symmetrical. We believe that it is important to be able to work with, and challenge where necessary, Ofgem's consultants to ensure adequate allowances are derived at the time. The implementation of such an incentive will allow GDNs to choose a level of spend with which they feel comfortable.

**Question 7: Should the mains replacement incentive mechanism be carried forward in its current form, adjusted for particular factors such as service pipes, or abandoned in favour of a more generic incentive?**

88. We support the continuation of the Mains Replacement Incentive Mechanism (MRIM), but think that it should be expanded to cover service pipes and larger diameter mains.
89. As recognised at the time of the last review, accurate forecasting of replacement workload over a five-year control period is difficult, with particular uncertainty around the mains diameter mix. Going forward, volumes should be more predictable but may still be subject to new requirements from the HSE, and the MRIM provides flexibility for changes in workload volume and diameter mix. Together with the pre-defined efficient unit cost for each diameter, this mechanism ensures that the GDN is appropriately funded for the work that is actually carried out. We believe its introduction has been an effective development.
90. We believe a number of enhancements are required to further improve the current mechanism. These include:
- Inclusion of additional larger diameter mains bands, i.e. > 12 inch;
  - Inclusion of replacement services;
  - Removal of the asymmetric sharing factors; and
  - Removal of the revenue cap.
91. Ofgem may also wish to consider smoothing the current revenue adjustment (DNMRA) to reduce the impact on annual transportation charges.

**Question 8: Is it appropriate to adopt rolling incentives for operating expenditure for gas distribution?**

92. We note that Ofgem have, in the past, faced difficulties when attempting to implement longer term rolling incentives for operating expenditure, not least due to differences in capitalisation policies between networks. Rolling opex incentives may be easier to implement for GDNs than DNOs because of their common accounting heritage.
93. Whilst we agree with the principle that seeks to remove periodicity in relation to operating expenditure, the degree to which an appropriate balance of risk and reward can be established is dependent upon not only the baseline set, but also the extent to which the assumed efficiency glide path can be achieved. Typically, costs to achieve efficiency

initiatives have not been factored into allowances, which ultimately makes the achievement of the glide path even more difficult.

94. Furthermore, rolling opex incentives do not distinguish between cost movements as a result of improving efficiency and exogenous factors. To this end, it is important that any such incentive be supplemented by appropriate uncertainty mechanisms.

**Question 9: How can the quality of service arrangements be improved? In particular what are your views on the high level options proposed by Ofgem for the quality of service and outputs arrangements for 2008-2013?**

95. The design and scope of any quality of service arrangements must balance value to the customer with the cost of implementing any changes. The table below shows the breadth of coverage of the existing Standards of Service regime for the types of activity which we undertake and the customer interface which occurs on a daily basis.

<b>Customer Interaction</b> <b>GDN Activities</b>	<b>Public Reported Escapes (Internal)</b>	<b>(Public Reported Escapes (External) / Repairs</b>	<b>Third Party Damage/ Water Ingress</b>	<b>Mains Replacement</b>	<b>New Connections / Service Alts</b>
Initial Contact	OS1	OS1	OS1	OS2	OS1/GS8
Agree Contract	n/a	n/a	n/a	n/a	GS4-7,9,10
Attend/Work on Site	OS5	OS5	OS5	OS2	GS11
Street-works	n/a	TMA	TMA	TMA	TMA
Private Reinst'ment	n/a	GS2	GS2	GS2	n/a
Supply Interruption	n/a	GS1/GS3	LoU/GS3	GS3	GS11
Reconnection	n/a	OS3	OS3	-	GS11
Complaints	OS4	OS4	OS4	OS4	OS4

OS – Overall Standards

GS – Guaranteed Standards

TMA – Traffic Management Act

LoU – Letter of Understanding

96. The table supports our view that the current suite of service standards cover those areas which customers value. However, we do agree with Ofgem over the complexity of the current arrangements, and that it is timely to consider options for simplification.
97. We would be happy to engage and work closely with Ofgem and energywatch as part of the price control process to develop and improve the existing framework so as to provide meaningful quality of service information to customers. Areas in which we believe

improvements could be made include the simplification of outputs in relation to connections activities under both the Guaranteed Standards and Licence Condition D10 requirements. We note that changes to the current suite of standards are being discussed as part of the BPQ process.

98. We welcome Ofgem's decision that the introduction of a scheme similar to electricity distribution measuring the number and duration of supply interruptions is not appropriate in gas distribution, given the low frequency of unplanned interruptions. The current mains replacement incentives encourage the efficient restoration of supply to ensure productivity is optimised by GDN and therefore we do not believe that a new standard of service for reconnection following a mains replacement job is necessary or would justify the additional cost and bureaucracy.

#### *Combined performance measures*

99. We are happy to explore the option of a combined performance measure with Ofgem, if this would produce benefits in terms of clearer performance information for our customers and stakeholders. In particular, we would like to discuss whether Ofgem is minded to address the GDNs' quality of service to different customer groups and expand the current scope to include our relationship with shippers, IGTs or Independent Connection Providers (ICPs). At present, these relationships are enshrined in the Unified Network Code (UNC).
100. We are also keen to understand Ofgem's views on the link between the composite performance score and price control revenues, in terms of potential incentives and exposure and the likely timing for implementation. It must be recognised however that the introduction of any combined measure is likely to require a degree of business process, systems and contractual changes that will need to be factored into business plans going forward.

#### *Third party and water ingress arrangements*

101. National Grid endeavours to restore supplies to customers interrupted by third parties, including interruption by water ingress, as quickly as possible, compensating customers in accordance with the requirements of the existing Letter of Understanding. We are supportive of reviewing these arrangements for both the extension year and for the main price control period.
102. We are concerned that the "no change" option includes the removal of the cap on any liabilities incurred as a result of third party or water ingress interruptions. Whilst we recognise that the probability of the single incident or annual cap being breached is low, should this occur, the potential liabilities exposure for the GDN could be significant. We do not agree that

removal would cause 'no material change in risk' for the GDNs just because the risk the cap being exceeded is low. This would be akin to saying that householders would be prudent not to have home rebuilding insurance given that the chances of them needing to claim are extremely low. In addition, the basis for our existing opex allowances that will be used to set the one year control was that only the insurance costs for covering the risk up to the cap were funded.

103. As part of the longer term arrangements, Ofgem is consulting upon the possible inclusion of arrangements into the existing Supply Restoration Guaranteed Standard for domestic consumers, and into the UNC for non-domestic consumers. As such events are not caused by National Grid and are outside of our control, we believe that it would be best to continue to separate third party and water ingress payments from those payments for the restoration of supply under the Guaranteed Standards and UNC. This will ensure transparency for the funding of the compensation levels for these events. We would not therefore support their inclusion into the Gas (Standards of Performance) Regulations and UNC. Furthermore, these events should not form part of a composite quality of service performance score for the GDN.

***Question 10: What are the advantages and disadvantages of the different approaches to setting capacity outputs and providing appropriate incentives for efficient behaviour by the GDNs in the next price control?***

104. We do not believe that explicit outputs to deliver the 1 in 20 obligation should be set as part of this price review. The current approach, of including monies to deliver new investment within the overall price control, has worked well to date and has provided appropriate incentives to deliver the efficient outcome. Looking forward, monies should continue to be allowed within the main control, and not be subject to separate outputs, given the uncertainty that exists regarding framework changes such as NTS exit and GDN interruption. Given the lack of experience in such areas, we do not believe it is possible to set realistic output measures for the forthcoming control period at this stage.

***Question 11: Are there any other areas where outputs or output based incentives for GDNs should be developed including safety and the accuracy of gas pipeline records? If so, what should they be?***

105. We do not believe that further outputs or output based incentives in relation to the safety of our gas transportation networks are necessary. Whilst not easy to measure, we consider that safety outputs are explicit within our existing Licence Conditions, Guaranteed Standards and our other HSE obligations.

106. Pipeline record accuracy is affected by a number of factors including the historic source data, the geographical background of digital mapping, boundary building line and ground level changes since construction, age of data, hand offs between parties laying and recording mains and transposition errors.
107. We recognise that our records are not 100% correct and we take every practical opportunity to improve the accuracy with which we record the location of our assets. Developments in this area include:
- The introduction of a suite of specific policies and procedures to improve the standards of recording information and to correct inaccuracies identified.
  - Section 79 of the New Roads and Street Works Act requires that, "In preparing the record, the location and route of the apparatus shall be recorded so that the measured position shall be within 300mm of the actual position and the recorded position shall be within 500mm of the actual position".
  - We have developed arrangements to pay Utility Infrastructure Providers (UIPs) and IGTs for the additional cost of mains extensions where a main has been inaccurately recorded. These arrangements were enhanced in September 2005 to include a payment where a main was found to be a different material/size from that recorded.
108. We believe that the existing combination of statutory requirements, internal controls and financial compensation represents a comprehensive and efficient approach.

***Question 12: Does any aspect of the operation of a GDN require more investment in technical innovation than occurs at present?***

109. We believe that Research and Development (R&D) is an important element of our ongoing drive to continually improve safety and efficiency. Explicit allowances should be made for R&D as part of the overall price control allowance, recognising that pay-back periods for such investment often extend beyond the price control period. At present we invest in technical innovation, with a focus on asset management decision making and improving existing methods and materials, rather than the development of new technologies.
110. Where technical innovation has industry wide application, the Gas Distribution Collaborative Forum has agreed to consider joint industry projects and, for such projects, industry wide incentive schemes would prove valuable.

**Question 13: Should Ofgem consider any other form of incentive mechanism in the context of GDPCR?**

111. We continue to believe that further wide-ranging changes to the current overall incentive regime are not necessary at this stage.

**Chapter Five: Financial issues**

**Question 1: Is Ofgem's approach of calculating a post-tax cost of capital and an ex ante tax allowance appropriate?**

112. A move to post tax as part of the cost of capital assumptions at the extension year will represent a significant financial hit to GDNs within any overall settlement. Whilst we acknowledge that pre-tax treatment can be portrayed as a benefit, it is important to remember that the tax treatment was well recognised by Ofgem during the last review and taken into account in striking the balance between shareholders and consumers.
113. Given this, we remain of the view that in the absence of evidence to the contrary, the current assumptions, including that of pre-tax, are appropriate for the extension year and should therefore be rolled forward simply and transparently. To simply move to a post tax approach or apply the outcome of TPCR would not be appropriate without a full review of all other factors.
114. We do not believe that there is sufficient time for Ofgem to conduct a full review of the cost of capital for gas distribution as part of the extension year process, taking on board outcomes from TPCR and differential risk analysis. We would caution against such an approach at this stage, particularly since areas of additional risk such as the decision on capex rolling incentives are yet to be finalised.

**Question 2: What, if any, financial indicators should be used to assess financeability (also relevant for the main control)?**

115. The most appropriate indicators to assess financeability in relation to debt finance remain those used by the credit rating agencies. Thought must also be given to those indicators used to assess equity.

*Debt financing*

116. The conditions of the GDN Licence specify Moody's, Standard & Poors and Fitch as appropriate agencies for assessing the credit quality of the regulated businesses. Furthermore, the licence specifies a cash lock up if any of these ratings drops below 'BBB-stable'. We believe however that it would be appropriate to look at the key indicators used by all of these agencies and ensure that the combination of limits set by each agency are achievable at an "A" grade credit rating to allow room for manoeuvre.
117. The key indicators used to assess the creditworthiness of the GDNs by the three agencies are:

	<b>Moody's Investor Service</b>	<b>Standard &amp; Poors</b>	<b>Fitch Ratings</b>
<b>Funds from operations interest cover</b>	✓	✓	
<b>Retained cash flow to debt</b>	✓		
<b>Funds from operations to debt</b>	✓	✓	
<b>Gearing</b>	✓	✓	
<b>EBITDA / Interest</b>			✓
<b>Net debt / RAV</b>			✓
<b>Net debt / EBITDA</b>			✓

*Equity Financing*

118. Since the GDNs are, or are likely to be assumed by the regulator to be, funded by a mixture of equity and debt, it is also appropriate to consider indicators that will be used by providers of equity finance to determine financeability. The most commonly used indicators in the utility industry to assess financeability from an equity perspective are dividend yield, EBITDA and Price/Earnings (P/E).

***Question 3: Should Ofgem use its traditional approach to calculate the cost of capital or should other approaches be considered?***

119. Whilst we agree that the rather hybrid form of CAPM currently used by Ofgem remains the appropriate basis upon which to assess the cost of capital for the main price control from

2008/9 onwards, we do not believe that it should be used in isolation when determining an appropriate cost of capital for gas distribution.

120. CAPM is a theoretical model premised on stylised and simplified assumptions to model the workings of the capital markets. Parameter instability, particularly when estimating the cost of equity, has led to CAPM substantially underestimating actual returns over time. We would urge Ofgem to continue to exercise caution when interpreting the results derived from CAPM analysis and to conduct a cross check using alternative models such as the Dividend Growth Model or a top down approach which not only considers regulatory precedent, but also the regulatory risk faced over the forthcoming period.

***Question 4: How should Ofgem approach the issue of the level of gearing to be used in the calculation of the tax allowance? Should Ofgem ensure that consumers share in any benefits arising from companies having higher actual gearing than the regulatory assumes?***

121. We believe that Ofgem should continue to use the principles established as part of DPCR4 in relation to the level of gearing assumed within the calculation of the tax allowance. Gearing should initially be established on a notional level, consistent with assumptions elsewhere in the financial calculations, and rolled forward using the cash flows established as part of the settlement process.

***Question 5: Are there any arguments for changing the depreciation rates used in the price control?***

122. The current approach used for determining depreciation rates used as part of the price control process is appropriate given the environment within which we find ourselves. However, in developing networks into the future, we will need to consider the stranding risk associated with the potential depletion of gas supplies.
123. There are two obvious avenues of mitigation in respect of this stranding risk that is likely to become apparent in future price controls. The first would be to alter existing depreciation rates and accelerate the depreciation of the regulatory asset value. The second is to factor such risks into the allowed cost of capital. It is arguable that such risks are unique to the gas industry. Our preference at this stage would be to accelerate the depreciation of the regulatory asset base.

124. We do not have any particular views on the level of acceleration but may submit evidence later in the review.

***Question 6: Is Ofgem's initial view on the treatment of pensions, and in particular the treatment of the GDNs' pension deficits, appropriate?***

125. Ofgem has already acknowledged that much of the debate on the issues of pensions deficits and allowances will be discussed within TPCR and as such, National Grid has fully outlined its position on general pension issues as part of its response to TPCR Initial Proposals.
126. We support Ofgem's proposed treatment of pension deficit costs in the Gas Distribution Price Control Review and believe that all of the deficit costs allocated to GDNs should be recoverable as they relate solely to our active employees. Issues relating to the recovery of ERDC's prior to April 2004 and legacy pensioners should be dealt with as part of the TPCR.
127. We acknowledge Ofgem's view that the recovery of ERDC's post April 2004 should be a matter for shareholders, and not customers, in line with the principles established as part of DPCR4. It must be recognised however, that severance costs are often inevitable when delivering the efficiencies assumed as part of the price control, from which the consumer immediately benefits.
128. In relation to Ofgem's proposal to carry out an 'overs and unders' calculation for the last price control period, we are supportive and believe that this calculation should also include the regulated element of third parties activities in line with previous Ofgem guidance. We agree that allowances for the extension year should also be re-visited to ensure that pension contribution allowances remain reflective of actual rates.
129. We note Ofgem's intention to complete the review of pensions prior to the publication of the Final Proposals and would urge Ofgem to include their findings as part of the extension year proposals.

***Question 7: Is Ofgem's proposal on the mechanism for recharging NTS pension costs appropriate?***

130. Ofgem's proposal to recharge NTS pensions costs via a specific annualised charge to each GDN is appropriate and represents the most practical solution.

**Question 8: What should be the timing of allowances for under recoveries from the current price control and deficit repair costs?**

131. In the case of National Grid Gas Distribution, it is likely that the majority, if not all, deficit repair costs will be funded at the start of the main price control review. However, given the likely effects on consumer prices should regulatory funding follow the same profile, it may be appropriate to consider smoothing recovery of deficit repair costs, and under recoveries from the current price control over a suitable time period.
132. If a smoothing approach is adopted however, we believe the maximum time period over which the money is recovered from customers should be ten years, consistent with the period allowed by the Pensions Regulator. Any smoothing process undertaken in relation to under recoveries and deficit repair must be NPV neutral.

**Question 9: How will the changes to pensions law affect the price control?**

133. Recent changes to pension law have had a major impact on the legal environment surrounding final salary pension schemes. In particular, the Pensions Act 2004 includes new scheme funding requirements, a new Pensions Regulator and the introduction of a Pension Protection Fund (PPF).
134. We believe it is important that Ofgem's assessment of pension costs reflects the impact of the Pensions Act, in particular:
- The assessment of liability valuation;
  - Scheme funding requirements;
  - PPF levy costs; and
  - Assumptions over the timing of deficit payments.

**Chapter Six: Other issues**

**Question 1: Are the three options for the funding of xoserve appropriate? Should we consider different options?**

135. Of the three options discussed by Ofgem within the consultation, a move to core services plus elements of User Pays (option three) would appear to meet the needs of Ofgem, Transporters and shippers in principle.

136. We are supportive of this option on the assumption that the core services are the current services that xoserve provide to, and on behalf of, Gas Transporters, such as the provision, recording, calculating and initial billing of transportation volumes, capacity booking and the balancing regime. It will enable certainty and stability for the existing services whilst allowing shippers to request higher value services as they see fit and with exposure to the additional costs involved.
137. A clear process will need to be implemented to define what services should be classified as User Pays, but one possible definition might include the following:
- Transactional Services which can be allocated to individual shippers e.g. shipper queries, and
  - Future changes. The Class 3 Modifications process, i.e. those that do not benefit the wider community, already supports this principle, where Class 3 Modifications are ones that have no benefit for the transporter and are paid for by the shippers. The shippers agree between them how the costs are to be allocated. However, we recognise that this process has never fully been utilised, as to date shippers have withdrawn their requests due to the cost involved and the complexity of allocation.
138. The other two options 'Do Nothing' and 'Do Nothing except promote dialogue' are both clearly workable. However, both carry the risk of parties raising self-serving modifications that they are not exposed to the cost of and therefore could lead to costs being incurred inefficiently.

***Question 2: Should Ofgem consider the outcome of an industry dialogue as part of its assessment of the funding required to replace UK-Link?***

139. Over the next seven years there is a programme of projects to replace and enhance the xoserve systems, including UK Link. The two key UK Link activities planned within this period are the Technology Refresh and the UK Link Re-write. The Technology Refresh is primarily to maintain the status quo functionality. To ensure the integrity of the system, it must be completed by the end of 2007. As the Refresh will not impact on current functionality or the services provided by xoserve, we do not believe that this project should be the subject of industry dialogue as part of its assessment on the funding required to replace UK-Link.
140. The Re-write however is a more significant activity and will impact the functionality of UK Link and the interface with Shipper systems, the scope of which will be discussed with industry participants. Therefore, we agree with Ofgem that it is appropriate to consider the outcome of industry dialogue on the UK Link Re-write in its assessment on the funding required to replace UK-Link.

**Question 3: Which, if any, of the 5 options for facilitating network extensions should Ofgem consider in more detail?**

141. In order to successfully tackle the issue of fuel poverty, a combination of initiatives will be required. We note the five options outlined by Ofgem within the consultation document and would like to propose an additional variation on option five.

*Option one – No regulatory intervention*

142. We do not believe that option one in its current form will incentivise GDNs to tackle fuel poverty. Whilst it is true that funding for infill projects and other energy products is available from a number of sources, this option does not acknowledge the levels of co-ordination needed to ensure that any fuel poverty programme is successful. Our experience with the current National Grid Affordable Warmth Programme (AWP) is that significant benefits can be delivered but only with an entity such as the AWP providing the co-ordination of funding sources and other aspects of the project. Our experience is that such programmes work most effectively when the agency is an independent 'not for profit' organisation.

*Option two – Change the application of the 10-metre rule*

143. It is unlikely that the application of the 10m allowance to all connections, regardless of their proximity to a relevant main, would materially reduce fuel poverty. Over 95% of properties within an infill in our networks would automatically qualify for the 10m allowance under the current rules. We believe that this option would mostly benefit those not in fuel poverty whose properties are generally more isolated from the gas network.

*Option three – Implement an incentive scheme*

144. Further clarity will need to be provided on this option before detailed comments are offered. It is not clear whether the financial incentive would be the capital required for infrastructure or the funding required to resource a small agency (such as our Affordable Warmth Programme) to provide a coordinated approach for targeting fuel poverty. It is also unclear how funds would be allocated and how effective this would be in its own right to making a significant impact in tackling fuel poverty.

*Option four – Net-back pricing for infill extensions carried out by GDN*

145. We believe that further detail on this option is needed for us to form a view on whether it could be effective. In particular, it is not clear what is meant by "*this amount (amount per connection) could be subtracted from the costs charged by the GDN to IGTs for work on their*

*network*” since GDNs do not undertake any chargeable works on behalf of IGTs. IGTs lay their own feeder mains and carry out their own final connections to GDN networks. However, we understand that the principle behind this option is to use the incremental transportation income from infill extensions to fund the extension, and so ensure that charges to other transportation customers would not have to rise. It is important to note that this principle would only work if there were no additional ‘upstream’ costs incurred on the distribution network by the incremental gas demand.

146. In addition, we believe that an element of cross subsidy is probably inevitable in order to deliver effective mechanisms to address fuel poverty via network extensions, and so the complexity of this option, which aims to avoid any apparent cross subsidy, is not warranted.

*Option five – Treat income from network extension as excluded revenue*

147. Of the options presented by Ofgem, we believe this to be the most feasible but further detail would be required in order to allow a proper evaluation to take place. From the information provided within the consultation document, this option may present some difficulties.
148. As with option four, the principle that existing consumers would not be worse off would only work if there were no additional ‘upstream’ costs incurred on the distribution network by the incremental gas demand. Further to this, this option does not appear at first sight to allow for competition within the infrastructure provider sector. Finally, whilst the infrastructure is a significant hurdle in the development of infills to tackle fuel poverty, a more holistic approach needs to be taken which tackles all of the barriers, such as the cost of new boilers, appliances and improved insulation. Option five, as with all of the other options discussed, does not on its own address these issues.

*An alternative approach (option six) that builds on Options four and five*

149. It may be possible to amend the existing Economic Test so that further capital expenditure is made available over and above the specific reinforcement triggered by the connection project without any detrimental effects on the existing user community.
150. The Economic Test is used by all GDNs to review additional loads to determine whether the connectee should contribute to the cost of any reinforcement work that is required. Under the current rules, a charging point is determined which identifies the point at which the load could connect to the network if there was not any other demand in the network. The connectee must pay for any infrastructure between this notional point and the customer.

151. In order to determine the level of contribution required, the test compares the average cost of a connection (using the transportation charges as a proxy for cost) to the specific reinforcement costs of the existing network, and not the cost of the infrastructure downstream of the charging point, as a result of a connection. If the reinforcement costs are greater than the average costs, the project is considered uneconomic and the connectee is required to contribute equal to the difference between the average cost and the specific cost.
152. If the average cost is greater than the specific cost, the connection is deemed economic and no contribution is required. Any remaining monies between the cost of reinforcement and the total revenue received are not however then used to subsidise the additional downstream infrastructure required to complete the connection. This remains a cost for the connectee.

*Proposed Amendment to the Economic Test to address Fuel Poverty*

153. Under option six, we propose the charging point be removed for approved infill projects that tackle fuel poverty. Instead, all of the costs of connecting, including reinforcement, new infrastructure (e.g. approach mains and connections), are compared to average cost of the load. Funds are then made available to the point where the specific cost of the infill equals the average cost to consumers. Where funds can be made available through the revised Economic Test, assets would be paid for and adopted by the GDN. This would reduce the upfront connections costs for the project, which are often a significant hurdle to the feasibility of any infill project to target fuel poverty.
154. To enable the scheme to be effective, co-ordination through a 'not for profit' organisation such as the Affordable Warmth Programme, would still be required in order to access external funding for the project and as such we believe that there is merit in the funding for such organisations to be provided under the price control (either as an opex allowance or under an incentive scheme as per option three).

*Advantages of Option six*

155. We believe that Option 6 has a number of advantages:
- Provides additional funding for infill projects that may be sufficient to make them economic.
  - Uses the principles of the ET but proposes a relaxation where social drivers, i.e. fuel poverty can be identified. This ensures transparency in the decision making process.
  - The use of the ET means that the transporter can make only contributions up to the level of the economic level. This prevents:
    - Uneconomic projects

- Cross subsidisation
- Additional burden to existing user community
- The proposal does not constrain competition for iGTs and connections. In fact, the proposal should encourage both UIPs and iGT's to undertake additional work where it becomes economic for them to do so.
- All customers would be billed on the same basis for their transportation charges.
- Is aligned to current regulatory environment.

***Question 4: Should Ofgem introduce a licence condition that requires NGG NTS to recover the excess costs associated with independent systems on behalf of GDNs?***

156. Before commenting on the specific question raised by Ofgem in relation to Independent Systems, it is worth reflecting on the background to the current regulatory arrangements. Independent Systems have, since the sale of networks in 2005 been subject to two separate legal undertakings put in place by Ofgem, the Secretary of State and National Grid in order to protect those customers connected to such systems from being adversely affected by industry change. These legal undertakings were entered into by both NTS and GDNs.
157. The first legal undertaking relates to Bulk Price Differential ("BPD"), i.e. the excess cost of Liquid Petroleum Gas ("LPG") supplied to these networks as compared to methane. NTS currently pays for this cost differential, albeit the legal undertaking provides for NTS to request the Authority's consent to recover this cost from GB customers after an agreed date. The undertaking requiring NTS to pay for the differential is due to fall away from 31st March 2008.
158. The second legal undertaking ensures that the transportation charges faced by consumers on Independent Systems are not higher than the GB average. To the extent that these transportation charges levied by the relevant GDN are above those of GB average, NTS can, post reconciliation, pay the excess to the relevant shippers at year end. This legal undertaking again provides for NTS to request the Authority's consent to recover the costs associated with this legal undertaking from GB customers after an agreed date. The undertaking requiring NTS to do this will fall away from 31st March 2008.

*Issues raised in the consultation document*

159. We recognise that provisions under the current legal undertakings are due to terminate on the 31st March 2008, and that a long term resolution for customers is required. A joint approach between the Secretary of State, Ofgem, and industry participants should be developed so that an enduring framework can be implemented with agreement from all affected parties. As such, we would like to confirm that we are happy to engage in the debate with Ofgem and the Secretary of State regarding the appropriate way forward.

160. Our initial view on the future treatment of BPD costs is for Ofgem to incorporate a new licence condition within the NTS licence, which mirrors the current legal undertaking and permits NTS to recover the revenue related to these costs on an ongoing basis. The effect would be to formalise the current arrangements further, ensuring that customers connected to Independent Systems would continue to be protected.
161. However, we believe that the legal undertaking which ensures that the transportation charges for customers connected to Independent Systems are lower or equal to GB average, should be removed. This does not seem appropriate given that there are separate GDN price controls and thus different prices for customers in each GDN. Instead, we believe this undertaking should be re-focused so that GDNs do not charge customers in Independent Systems in excess of the average transportation charges of those customers connected to the main distribution system within the same GDN region. This would align the charges of these customers with the regional operating costs borne by the GDNs and remove what has limited cost benefit in terms of the current reconciliation activity undertaken by NTS.
162. We note Ofgem's comments within the consultation document with respect to the cost of operating Independent Systems compared to the main gas distribution system. We believe that those GDNs who operate Independent Systems within their geographical network should be allowed to recover the efficient level of direct operating costs associated with these networks from the start of the next price control review, except where elements of these costs are currently recovered via an alternative mechanism such as the Bulk Price Differential. Where an alternative mechanism is used, the MAR of the GDN should be adjusted to reflect this.

## **Chapter Seven: Timetable and process**

### ***Question 1: What issues to be addressed as part of GDPCR should be considered in an impact assessment?***

163. Impact assessments should be conducted for those areas implemented as part of the extension or the main review that impose a cost on either the GDNs or customers in general. In such instances, it is imperative that a proper cost benefit analysis is conducted.
164. We believe the following issues should be considered as part of any impact assessment:
- Exit and interruptions reform
  - Network extensions

- Cost reporting frameworks
- Changes to the Standards of Service regime
- xoserve